PPL ELECTRIC UTILITIES CORPORATION

Appendices A through I
to Accompany the
Direct Testimony

of

Paul R. Moul
Managing Consultant
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Concerning
Rate of Return

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past twenty-nine years, I have continuously studied the rate of return requirements for cost of service regulated firms. In this regard, I have supervised the preparation of rate of return studies which were employed in connection with my testimony and in the past for other individuals. I have presented direct

testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty (30) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, and West Virginia; and the Philadelphia Gas Commission. My testimony has been offered in over 200 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000).

Further, I have been the consultant to the New York Chapter of the National Association of Water Companies which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000).

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

I am a member of the Society of Utility and Regulatory Financial Analysis (formerly the National Society of Rate of Return Analysts) and have attended several Financial Forums sponsored by the Society. I attended the first National Regulatory Conference at the Marshall-Wythe School of Law, College of William and Mary. I also attended an Executive Seminar

sponsored by the Colgate Darden Graduate Business School of the University of Virginia concerning Regulated Utility Cost of Equity and the Capital Asset Pricing Model. In October 1984, I attended a Standard & Poor's Seminar on the Approach to Municipal Utility Ratings, and in May 1985, I attended an S&P Seminar on Telecommunications Ratings.

My lecture and speaking engagements include:

Date	Occasion	Sponsor
April 2001	Thirty-third Financial Forum	Society of Utility & Regulatory Financial Analysts
December 2000	Pennsylvania Public Utility Law Conference: Non-traditional Players in the Water Industry	Pennsylvania Bar Institute
July 2000	EEI Member Workshop Developing Incentives Rates: Application and Problems	Edison Electric Institute
February 2000	The Sixth Annual FERC Briefing	Except and Bruder, Gentile & Marcoux, LLP
March 1994	Seventh Annual Proceeding	Electric Utility Business Environment Conf.
May 1993	Financial School	New England Gas Assoc.
April 1993	Twenty-Fifth Financial Forum	National Society of Rate of Return Analysts
June 1992	Rate and Charges Subcommittee Annual Conference	American Water Works Association
May 1992	Rates School	New England Gas Assoc.
October 1989	Seventeenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners Florida Public Service Commission and University of Utah
October 1988	Sixteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah
May 1988	Twentieth Financial	National Society of

	Forum	Rate of Return Analysts
October 1987	Fifteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah
September 1987	Rate Committee Meeting	American Gas Association
May 1987	Pennsylvania Chapter annual meeting	National Association of Water Companies
October 1986	Eighteenth Financial Forum	National Society of Rate of Return
October 1984	Fifth National on Utility Ratemaking Fundamentals	American Bar Association
March 1984	Management Seminar	New York State Telephone Association
February 1983	The Cost of Capital Seminar	Temple University, School of Business Admin.
May 1982	A Seminar on Regulation and The Cost of Capital	New Mexico State University, Center for Business Research and Services
October 1979	Economics of Regulation	Brown University

APPENDIX B TO DIRECT TESTIMONY OF PAUL R. MOUL

RATESETTING PRINCIPLES

Under traditional cost of service regulation, an agency engaged in ratesetting, such as the Commission, serves as a substitute for competition. In setting rates, a regulatory agency must carefully consider the public's interest in reasonably priced, as well as safe and reliable, service. The level of rates must also provide an opportunity to earn a rate of return for the public utility and its investors that is commensurate with the risk to which the invested capital is exposed so that the public utility has access to the capital required to meet its service responsibilities to its customers. Without an opportunity to earn a fair rate of return, a public utility will be unable to attract sufficient capital required to meet its responsibilities over time.

It is important to remember that regulated firms must compete for capital in a global market with non-regulated firms, as well as municipal, state and federal governments. Traditionally, a public utility has been responsible for providing a particular type of service to its customers within a specific market area. Although this relationship with its customers has been changing, it remains quite different from a non-regulated firm which is free to enter and exit competitive markets in accordance with available business opportunities.

As established by the landmark Bluefield and Hope cases,[1] several tests must be satisfied to demonstrate the fairness or reasonableness of the rate of return. These tests include a determination of whether the rate of return is (i) similar to that of other financially sound businesses having similar or comparable risks, (ii) sufficient to ensure confidence in the financial integrity of the public utility, and (iii) adequate to maintain and support the credit of the utility, thereby enabling it to attract, on a reasonable cost basis, the funds necessary to

[1] Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

satisfy its capital requirements so that it can meet the obligation to provide adequate and reliable service to the public.

A fair rate of return must not only provide the utility with the ability to attract new capital, it must also be fair to existing investors. An appropriate rate of return which may have been reasonable at one point in time may become too high or too low at a subsequent point in time, based upon changing business risks, economic conditions and alternative investment opportunities. When applying the standards of a fair rate of return, it must be recognized that the end result must provide for the payment of interest on the company's debt, the payment of dividends on the company's stock, the recovery of costs associated with securing capital, the maintenance of reasonable credit quality for the company, and support of the company's financial condition, which today would include those measures of financial performance in the areas of interest coverage and adequate cash flow derived from a reasonable level of earnings.

EVALUATION OF RISK

The rate of return required by investors is directly linked to the perceived level of risk. The greater the risk of an investment, the higher is the required rate of return necessary to compensate for that risk all else being equal. Because investors will seek the highest rate of return available, considering the risk involved, the rate of return must at least equal the investor-required, market-determined cost of capital if public utilities are to attract the necessary investment capital on reasonable terms.

In the measurement of the cost of capital, it is necessary to assess the risk of a firm. The level of risk for a firm is often defined as the uncertainty of achieving expected performance, and is sometimes viewed as a probability distribution of possible outcomes. Hence, if the uncertainty of achieving an expected outcome is high, the risk is also high. As a consequence, high risk firms must offer investors higher returns than low risk firms which pay less to attract capital from investors. This is because the level of uncertainty, or risk of not realizing expected returns, establishes the compensation required by investors in the capital markets. Of course, the risk of a firm must also be considered in the context of its ability to actually experience adequate earnings which conform with a fair rate of return. Thus, if there is a high probability that a firm will not perform well due to fundamentally poor market conditions, investors will demand a higher return.

The investment risk of a firm is comprised of its business risk and financial risk. Business risk is all risk other than financial risk, and is sometimes defined as the staying power of the market demand for a firm's product or service and the resulting inherent uncertainty of realizing expected pre-tax returns on the firm's assets. Business risk encompasses all operating factors, e.g., productivity, competition, management ability, etc. that bear upon the expected

pre-tax operating income attributed to the fundamental nature of a firm's business. Financial risk results from a firm's use of borrowed funds (or similar sources of capital with fixed payments) in its capital structure, i.e., financial leverage. Thus, if a firm did not employ financial leverage by borrowing any capital, its investment risk would be represented by its business risk.

It is important to note that in evaluating the risk of regulated companies, financial leverage cannot be considered in the same context as it is for non-regulated companies. Financial leverage has a different meaning for regulated firms than for non-regulated companies. For regulated public utilities, the cost of service formula gives the benefits of financial leverage to consumers in the form of lower revenue requirements. For non-regulated companies, all benefits of financial leverage are retained by the common stockholder. Although retaining none of the benefits, regulated firms bear the risk of financial leverage. Therefore, a regulated firm's rate of return on common equity must recognize the greater financial risk shown by the higher leverage typically employed by public utilities.

Although no single index or group of indices can precisely quantify the relative investment risk of a firm, financial analysts use a variety of indicators to assess that risk. For example, the creditworthiness of a firm is revealed by its bond ratings. If the stock is traded, the price-earnings multiple, dividend yield, and beta coefficients (a statistical measure of a stock's relative volatility to the rest of the market) provide some gauge of overall risk. Other indicators, which are reflective of business risk, include the variability of the rate of return on equity, which is indicative of the uncertainty of actually achieving the expected earnings; operating ratios (the percentage of revenues consumed by operating expenses, depreciation, and taxes other than income tax), which are indicative of profitability; the quality of earnings,

which considers the degree to which earnings are the product of accounting principles or cost deferrals; and the level of internally generated funds. Similarly, the proportion of senior capital in a company's capitalization is the measure of financial risk which is often analyzed in the context of the equity ratio (i.e., the complement of the debt ratio).

APPENDIX D TO DIRECT TESTIMONY OF PAUL R. MOUL

COST OF EQUITY--GENERAL APPROACH

Through a fundamental financial analysis, the relative risk of a firm must be established prior to the determination of its cost of equity. Any rate of return recommendation which lacks such a basis will inevitably fail to provide a utility with a fair rate of return except by coincidence. With a fundamental risk analysis as a foundation, standard financial models can be employed by using informed judgment. The methods which have been employed to measure the cost of equity include: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") approach, the Capital Asset Pricing Model ("CAPM") and the Comparable Earnings ("CE") approach.

The traditional DCF model, while useful in providing some insight into the cost of equity, is not an approach that should be used exclusively. The divergence of stock prices from company-specific fundamentals can provide a misleading cost of equity calculation. As reported in The Wall Street Journal on June 6, 1991, a statistical study published by Goldman Sachs indicated that only 35% of stock price growth in the 1980's could be attributed to earnings and interest rates. Further, 38% of the rise in stock prices during the 1980's was attributed to unknown factors. The Goldman Sachs study highlights the serious limitations of a model, such as DCF, which is founded upon identification of specific variables to explain stock price growth. That is to say, when stock price growth exceeds growth in a company's earnings per share, models such as DCF will misspecify investor expected returns which are comprised of capital gains, as well as dividend receipts. As such, a combination of methods should be used to measure the cost of equity.

The Risk Premium analysis is founded upon the prospective cost of long-term debt, i.e., the yield that the public utility must offer to raise long-term debt capital directly from investors.

To that yield must be added a risk premium in recognition of the greater risk of common equity over debt. This additional risk is, of course, attributable to the fact that the payment of interest and principal to creditors has priority over the payment of dividends and return of capital to equity investors. Hence, equity investors require a higher rate of return than the yield on long-term corporate bonds.

The CAPM is a model not unlike the traditional Risk Premium. The CAPM employs the yield on a risk-free interest-bearing obligation plus a premium as compensation for risk. Aside from the reliance on the risk-free rate of return, the CAPM gives specific quantification to systematic (or market) risk as measured by beta.

The Comparable Earnings approach measures the returns expected/experienced by other non-regulated firms and has been used extensively in rate of return analysis for over a half century. However, its popularity diminished in the 1970s and 1980s with the popularization of market-based models. Recently, there has been renewed interest in this approach. Indeed, the financial community has expressed the view that the regulatory process must consider the returns which are being achieved in the non-regulated sector so that public utilities can compete effectively in the capital markets. Indeed, with additional competition being introduced throughout the traditionally regulated public utility industry, returns expected to be realized by non-regulated firms have become increasing relevant in the ratesetting process. The Comparable Earnings approach considers directly those requirements and it fits the established standards for a fair rate of return set forth in the landmark decisions on the issue of rate of return. These decisions require that a fair return for a utility must be equal to that earned by firms of comparable risk.

DISCOUNTED CASH FLOW ANALYSIS

Discounted Cash Flow ("DCF") theory seeks to explain the value of an economic or financial asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. Thus, if $100 is to be received in a single payment 10 years subsequent to the acquisition of an asset, and the appropriate risk-related interest rate is 8%, the present value of the asset would be $46.32 (Value = $100 ÷ $(1.08)^{10}$) arising from the discounted future cash flow. Conversely, knowing the present $46.32 price of an asset (where price = value), the $100 future expected cash flow to be received 10 years hence shows an 8% annual rate of return implicit in the price and future cash flows expected to be received.

In its simplest form, the DCF theory considers the number of years from which the cash flow will be derived and the annual compound interest rate which reflects the risk or uncertainty associated with the cash flows. It is appropriate to reiterate that the dollar values to be discounted are future cash flows.

DCF theory is flexible and can be used to estimate value (or price) or the annual required rate of return under a wide variety of conditions. The theory underlying the DCF methodology can be easily illustrated by utilizing the investment horizon associated with a preferred stock not having an annual sinking fund provision. In this case, the investment horizon is infinite, which reflects the perpetuity of a preferred stock. If P represents price, Kp is the required rate of return on a preferred stock, and D is the annual dividend (P and D with time subscripts), the value of a preferred share is equal to the present value of the dividends to be received in the future discounted at the appropriate risk-adjusted interest rate, Kp. In this circumstance:

$$P_0 = \frac{D_1}{(1+Kp)} + \frac{D_2}{(1+Kp)^2} + \frac{D_3}{(1+Kp)^3} + \ldots + \frac{D_n}{(1+Kp)^n}$$

If $D_1 = D_2 = D_3 = \ldots D_n$ as is the case for preferred stock, and n approaches infinity, as is the case for non-callable preferred stock without a sinking fund, then this equation reduces to:

$$P_0 = \frac{D_1}{Kp}$$

This equation can be used to solve for the annual rate of return on a preferred stock when the current price and subsequent annual dividends are known. For example, with D_1 = \$1.00, and P_0 = \$10, then Kp = \$1.00 ÷ \$10, or 10%.

The dividend discount equation, first shown, is the generic DCF valuation model for all equities, both preferred and common. While preferred stock generally pays a constant dividend, permitting the simplification subsequently noted, common stock dividends are not constant. Therefore, absent some other simplifying condition, it is necessary to rely upon the generic form of the DCF. If, however, it is assumed that $D_1, D_2, D_3, \ldots D_n$ are systematically related to one another by a constant growth rate (g), so that $D_0 (1 + g) = D_1$, $D_1 (1 + g) = D_2$, $D_2 (1 + g) = D_3$ and so on approaching infinity, and if Ks (the required rate of return on a common stock) is greater than g, then the DCF equation can be reduced to:

$$P_0 = \frac{D_1}{Ks - g} \quad or \quad P_0 = \frac{D_0(1+g)}{Ks - g}$$

which is the periodic form of the "Gordon" model.[1] Proof of the DCF equation is found in all modern basic finance textbooks. This DCF equation can be easily solved as:

[1] Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in

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

which is the periodic form of the Gordon Model commonly applied in estimating equity rates of return in rate cases. When used for this purpose, *Ks* is the annual rate of return on common equity demanded by investors to induce them to hold a firm's common stock. Therefore, the variables D_0, P_0 and g must be estimated in the context of the market for equities, so that the rate of return, which a public utility is permitted the opportunity to earn, has meaning and reflects the investor-required cost rate.

Application of the Gordon model with market derived variables is straightforward. For example, using the most recent prior annualized dividend (D_0) of \$0.80, the current price (P_0) of \$10.00, and the investor expected dividend growth rate (g) of 5%, the solution of the DCF formula provides a 13.4% rate of return. The dividend yield component in this instance is 8.4%, and the capital gain component is 5%, which together represent the total 13.4% annual rate of return required by investors. The capital gain component of the total return may be calculated with two adjacent future year prices. For example, in the eleventh year of the holding period, the price per share would be \$17.10 as compared with the price per share of \$16.29 in the tenth year which demonstrates the 5% annual capital gain yield.

Some DCF devotees believe that it is more appropriate to estimate the required return on equity with a model which permits the use of multiple growth rates. This may be a plausible approach to DCF, where investors expect different dividend growth rates in the near term and long run. If two growth rates, one near term and one long-run, are to be used in the context of a

the mid-1950's, J. B. Williams exposited the DCF model in its present form nearly two decades earlier.

price (P_0) of $10.00, a dividend ($D_0$) of $0.80, a near-term growth rate of 5.5%, and a long-run expected growth rate of 5.0% beginning at year 6, the required rate of return is 13.57% solved with a computer by iteration.

Use of DCF in Ratesetting

The DCF method can provide a misleading measure of the cost of equity in the ratesetting process when stock prices diverge from book values by a meaningful margin. When the difference between share values and book values is significant, the results from the DCF can result in a misspecified cost of equity when those results are applied to book value. This is because investor expected returns, as described by the DCF model, are related to the market value of common stock. This discrepancy is shown by the following example. If it is assumed, hypothetically, that investors require a 12.5% return on their common stock investment value (i.e., the market price per share) when share values represent 150% of book value, investors would require a total annual return of $1.50 per share on a $12.00 market value to realize their expectations. If, however, this 12.5% market-determined cost rate is applied to an original cost rate base which is equivalent to the book value of common stock of $8.00 per share, the utility's actual earnings per share would be only $1.00. This would result in a $.50 per share earnings shortfall which would deny the utility the ability to satisfy investor expectations.

As a consequence, a utility could not withstand these DCF results applied in a rate case and also sustain its financial integrity. This is because $1.00 of earnings per share and a 75% dividend payout ratio would provide earnings retention growth of just 3.125% (i.e., $1.00 x .75 = $0.75, and $1.00 - $0.75 = $0.25 ÷ $8.00 = 3.125%). In this example, the earnings retention growth rate plus the 6.25% dividend yield ($0.75 ÷ $12.00) would equal 9.375% (6.25% + 3.125%) as indicated by the DCF model. This DCF result is the same as the utility's rate of

dividend payments on its book value (i.e., $0.75 ÷ $8.00 = 9.375%). This situation provides the utility with no earnings cushion for its dividend payment because the DCF result equals the dividend rate on book value (i.e., both rates are 9.375% in the example). Moreover, if the price employed in my example were higher than 150% of book value, a "negative" earnings cushion would develop and cause the need for a dividend reduction because the DCF result would be less than the dividend rate on book value. For these reasons, the usefulness of the DCF method significantly diminishes as market prices and book values diverge.

Further, there is no reason to expect that investors would necessarily value utility stocks equal to their book value. In fact, it is rare that utility stocks trade at book value. Moreover, high market-to-book ratios may be reflective of general market sentiment. Were regulators to use the results of a DCF model, that fails to produce the required return when applied to an original cost rate base, they would penalize a company with high market-to-book ratios. This clearly would penalize a regulated firm and its investors that purchased the stock at its current price. When investor expectations are not fulfilled, the market price per share will decline and a new, different equity cost rate would be indicated from the lower price per share. This condition suggests that the current price would be subject to disequilibrium and would not allow a reasonable calculation of the cost of equity. This situation would also create a serious disincentive for management initiative and efficiency. Within that framework, a perverse set of goals and rewards would result, i.e., a high authorized rate of return in a rate case would be the reward for poor financial performance, while low rates of return would be the reward for good financial performance. As such, the DCF results should not be used alone to determine the cost of equity, but should be used along with other complementary methods.

Dividend Yield

The historical annual dividend yields are shown on and Schedule 3 for the Electric Group. The 2001-2005 five-year average dividend yield was 4.8% for the Electric Group. The monthly dividend yields for the past twelve months are shown graphically on Schedule 8. These dividend yields reflect an adjustment to the month-end closing prices to remove the pro rata accumulation of the quarterly dividend amount since the last ex-dividend date.

The ex-dividend date usually occurs two business days before the record date of the dividend (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment--usually about two to three weeks prior to the actual payment). During a quarter (here defined as 91 days), the price of a stock moves up ratably by the dividend amount as the ex-dividend date approaches. The stock's price then falls by the amount of the dividend on the ex-dividend date. Therefore, it is necessary to calculate the fraction of the quarterly dividend since the time of the last ex-dividend date and to remove that amount from the price. This adjustment reflects normal recurring pricing of stocks in the market, and establishes a price that will reflect the true yield on a stock.

A six-month average dividend yield has been used to recognize the prospective orientation of the ratesetting process as explained in the direct testimony. For the purpose of a DCF calculation, the average dividend yields must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future rather than the recent dividend payment annualized. An adjustment to the dividend yield component, when computed with annualized dividends, is required based upon investor expectation of quarterly dividend increases.

The procedure to adjust the average dividend yield for the expectation of a dividend increase during the initial investment period will be at a rate of one-half the growth component, developed below. The DCF equation, showing the quarterly dividend payments as D_0, may be stated in this fashion:

$$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$$

The adjustment factor, based upon one-half the expected growth rate developed in my direct testimony, will be 3.125% (6.25% x .5) for the Electric Group which assumes that two dividend payments will be at the expected higher rate during the initial investment period. Using the six-month average dividend yield as a base, the prospective (forward) dividend yield would be 4.28% (4.15% x 1.03125) for the Electric Group.

Another DCF model that reflects the discrete growth in the quarterly dividend (D_0) is as follows:

$$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$$

This procedure confirms the reasonableness of the forward dividend yield previously calculated. The quarterly discrete adjustment provides a dividend yield of 4.31% (4.15% x 1.03877) for the Electric Group. The use of an adjustment is required for the periodic form of the DCF in order to properly recognize that dividends grow on a discrete basis.

In either of the preceding DCF dividend yield adjustments, there is no recognition for the compound returns attributed to the quarterly dividend payments. Investors have the opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the periodic quarterly dividend payments (D_0), results in a third DCF formulation:

$$k = \left[\left(1 + \frac{D_0}{P_0}\right)^4 - 1\right] + g$$

This DCF equation provides no further recognition of growth in the quarterly dividend. Combining discrete quarterly dividend growth with quarterly compounding would provide the following DCF formulation, stating the quarterly dividend payments (D_0):

$$k = \left[\left(1 + \frac{D_0(1+g)^{.25}}{P_0}\right)^4 - 1\right] + g$$

A compounding of the quarterly dividend yield provides another procedure to recognize the necessity for an adjusted dividend yield. The unadjusted average quarterly dividend yield was 1.0375% (4.15% ÷ 4) for the Electric Group. The compound dividend yield would be 4.28% (1.010533^4-1) for the Electric Group, recognizing quarterly dividend payments in a forward-looking manner. These dividend yields conform with investors' expectations in the context of reinvestment of their cash dividend.

For the Electric Group, a 4.29% forward-looking dividend yield is the average (4.28% + 4.31% + 4.28% = 12.87% ÷ 3) of the adjusted dividend yield using the form $D_0/P_0\ (1+.5g)$,

the dividend yield recognizing discrete quarterly growth, and the quarterly compound dividend yield with discrete quarterly growth.

Growth Rate

If viewed in its infinite form, the DCF model is represented by the discounted value of an endless stream of growing dividends. It would, however, require 100 years of future dividend payments so that the discounted value of those payments would equate to the present price so that the discount rate and the rate of return shown by the simplified Gordon form of the DCF model would be about the same. A century of dividend receipts represents an unrealistic investment horizon from almost any perspective. Because stocks are not held by investors forever, the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, investor expected returns in the equity market are provided by capital appreciation of the investment as well as receipt of dividends. As such, the sale price of a stock can be viewed as a liquidating dividend which can be discounted along with the annual dividend receipts during the investment holding period to arrive at the investor expected return.

In its constant growth form, the DCF assumes that with a constant return on book common equity and constant dividend payout ratio, a firm's earnings per share, dividends per share and book value per share will grow at the same constant rate, absent any external financing by a firm. Because these constant growth assumptions do not actually prevail in the capital markets, the capital appreciation potential of an equity investment is best measured by the expected growth in earnings per share. Since the traditional form of the DCF assumes no change in the price-earnings multiple, the value of a firm's equity will grow at the same rate as earnings per share. Hence, the capital gains yield is best measured by earnings per share

growth using company-specific variables.

Investors consider both historical and projected data in the context of the expected growth rate for a firm. An investor can compute historical growth rates using compound growth rates or growth rate trend lines. Otherwise, an investor can rely upon published growth rates as provided in widely-circulated, influential publications. However, a traditional constant growth DCF analysis that is limited to such inputs suffers from the assumption of no change in the price-earnings multiple, i.e., that the value of a firm's equity will grow at the same rate as earnings. Some of the factors which actually contribute to investors' expectations of earnings growth and which should be considered in assessing those expectations, are: (i) the earnings rate on existing equity, (ii) the portion of earnings not paid out in dividends, (iii) sales of additional common equity, (iv) reacquisition of common stock previously issued, (v) changes in financial leverage, (vi) acquisitions of new business opportunities, (vii) profitable liquidation of assets, and (viii) repositioning of existing assets. The realities of the equity market regarding total return expectations, however, also reflect factors other than these inputs. Therefore, the DCF model contains overly restrictive limitations when the growth component is stated in terms of earnings per share (the basis for the capital gains yield) or dividends per share (the basis for the infinite dividend discount model). In these situations, there is inadequate recognition of the capital gains yields arising from stock price growth which could exceed earnings or dividends growth.

To assess the growth component of the DCF, analysts' projections of future growth influence investor expectations as explained above. One influential publication is The Value Line Investment Survey which contains estimated future projections of growth. The Value Line Investment Survey provides growth estimates which are stated within a common

economic environment for the purpose of measuring relative growth potential. The basis for these projections is the Value Line 3 to 5 year hypothetical economy. The Value Line hypothetical economic environment is represented by components and subcomponents of the National Income Accounts which reflect in the aggregate assumptions concerning the unemployment rate, manpower productivity, price inflation, corporate income tax rate, high-grade corporate bond interest rates, and Fed policies. Individual estimates begin with the correlation of sales, earnings and dividends of a company to appropriate components or subcomponents of the future National Income Accounts. These calculations provide a consistent basis for the published forecasts. Value Line's evaluation of a specific company's future prospects are considered in the context of specific operating characteristics that influence the published projections. Of particular importance for regulated firms, Value Line considers the regulatory quality, rates of return recently authorized, the historic ability of the firm to actually experience the authorized rates of return, the firm's budgeted capital spending, the firm's financing forecast, and the dividend payout ratio. The wide circulation of this source and frequent reference to Value Line in financial circles indicate that this publication has an influence on investor judgment with regard to expectations for the future.

There are other sources of earnings growth forecasts. One of these sources is the Institutional Brokers Estimate System ("IBES"), which has been published for many years. The IBES service provided data on consensus earnings per share forecasts and five-year earnings growth rate estimates. The publisher of IBES has been purchased by Thomson/First Call. The IBES forecasts have been integrated into the First Call consensus growth forecasts. The earnings estimates are obtained from financial analysts at brokerage research departments and from institutions whose securities analysts are projecting earnings for companies in the

First Call universe of companies. Other services that tabulate earnings forecasts and publish them are Zacks Investment Research and Market Guide (which is provided over the Internet by Reuters). As with the First Call forecasts, Zacks and Reuters/Market Guide provide consensus forecasts collected from analysts for most publically traded companies.

In each of these publications, forecasts of earnings per share for the current and subsequent year receive prominent coverage. That is to say, First Call/Thomson, Zacks, Reuters/Market Guide, and Value Line show estimates of current-year earnings and projections for the next year. While the DCF model typically focusses upon long-run estimates of growth, stock prices are clearly influenced by current and near-term earnings prospects. Therefore, the near-term earnings per share growth rates should also be factored into a growth rate determination.

Although forecasts of future performance are investor influencing[2], equity investors may also rely upon the observations of past performance. Investors' expectations of future growth rates may be determined, in part, by an analysis of historical growth rates. It is apparent that any serious investor would advise himself/herself of historical performance prior to taking an investment position in a firm. Earnings per share and dividends per share represent the principal financial variables which influence investor growth expectations.

Other financial variables are sometimes considered in rate case proceedings. For example, a company's internal growth rate, derived from the return rate on book common equity and the related retention ratio, is sometimes considered. This growth rate measure is represented by the Value Line forecast "*B*x*R*" shown on Schedule 10. Internal growth rates are often used as a proxy for book value growth. Unfortunately, this measure of growth is often

[2] As shown in a National Bureau of Economic Research monograph by John G. Cragg and Burton G. Malkiel, Expectations and the Structure of Share Prices, University of Chicago Press 1982.

not reflective of investor-expected growth. This is especially important when there is an indication of a prospective change in dividend payout ratio, earned return on book common equity, change in market-to-book ratios or other fundamental changes in the character of the business. Nevertheless, I have also shown the historical and projected growth rates in book value per share and internal growth rates.

Leverage Adjustment

As noted previously, the divergence of stock prices from book values creates a conflict within the DCF model when the results of a market-derived cost of equity are applied to the common equity account measured at book value for the purpose of determining the weighted average cost of capital is in the ratesetting context. This is the situation today where the market price of stock exceeds its book value for most companies. This divergence of price and book value also creates a financial risk difference, whereby the capitalization of a utility measured at its market value contains relatively less debt and more equity than the capitalization measured at its book value. It is a well-accepted fact of financial theory that a relatively higher proportion of equity in the capitalization has less financial risk than another capital structure more heavily weighted with debt. This is the situation for the Electric Group where the market value of its capitalization contains more equity than is shown by the book capitalization. The following comparison demonstrates this situation where the market capitalization is developed by taking the "Fair Value of Financial Instruments" (Disclosures about Fair Value of Financial Instruments -- Statement of Financial Accounting Standards ("FAS") No. 107) as shown in the annual report for these companies and the market value of the common equity using the price of stock. The comparison of capital structure ratios is:

	Capitalization at Market Value (Fair Value)	Capitalization at Book Value (Carrying Amounts)
Long-term Debt	44.19%	49.95%
Preferred Stock	1.20	1.49
Common Equity	54.62	48.57
Total	100.00%	100.00%

With regard to the capital structure ratios represented by the carrying amounts shown above, there are some variances from the ratios shown on Schedule 3. These variances arise from the use of balance sheet values in computing the capital structure ratios shown on Schedule 3 and the use of the Carrying Amounts of the Financial Instruments according to FAS 107 (the Carrying Amounts were used in the table shown above to be comparable to the Fair Value amounts used in the comparison calculations).

With the capital ratios calculated above, is necessary to first calculate the cost of equity for a firm without any leverage. The cost of equity for an unleveraged firm using the capital structure ratios calculated with market values is:

$$ku = ke - (((ku - i)\ 1\text{-}t)\ D / E) - (ku - d)\ P / E$$

$$8.93\% = 10.54\% - (((8.93\% - 5.96\%)\ .65)\ 44.19\%/54.62\%) - (8.93\% - 6.04\%)\ 1.20\%/54.62\%$$

where ku = cost of equity for an all-equity firm, ke = market determined cost equity, i = cost of debt[3], d = dividend rate on preferred stock[4], D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The formula shown above indicates that the cost of equity for a firm with 100% equity is 8.93% in the case of the Electric Group using the market value of the capitalization. Having determined that the cost of equity for a firm with 100% equity, the rate of return on common equity associated with the book value capital structure is:

[3] The cost of debt is the six-month average yield on Moody's A rated public utility bonds.

[4] The cost of preferred is the six-month average yield on Moody's "a" rated preferred stock.

1 $ke = ku + (((ku - i)\ 1\text{-}t)\ D / E) + (ku - d)\ P / E$

2 $11.01\% = 8.93\% + (((8.93\% - 5.96\%).65)\ 49.95\%/48.57\%) + (8.93\% - 6.04\%)\ 1.49\%/48.57\%$

INTEREST RATES

Interest rates can be viewed in their traditional nominal terms (i.e., the stated rate of interest) and in real terms (i.e., the stated rate of interest less the expected rate of inflation). Absent consideration of inflation, the real rate of interest is determined generally by supply factors which are influenced by investors willingness to forego current consumption (i.e., to save) and demand factors that are influenced by the opportunities to derive income from productive investments. Added to the real rate of interest is compensation required by investors for the inflationary impact of the declining purchasing power of their income received in the future. While interest rates are clearly influenced by the changing annual rate of inflation, it is important to note that the expected rate of inflation, that is reflected in current interest rates, may be quite different than the prevailing rate of inflation.

Rates of interest also vary by the type of interest bearing instrument. Investors require compensation for the risk associated with the term of the investment and the risk of default. The risk associated with the term of the investment is usually shown by the yield curve, i.e., the difference in rates across maturities. The typical structure is represented by a positive yield curve which provides progressively higher interest rates as the maturities are lengthened. Flat (i.e., relatively level rates across maturities) or inverted (i.e., higher short-term rates than long-term rates) yield curves occur less frequently.

The risk of default is typically associated with the creditworthiness of the borrower. Differences in interest rates can be traced to the credit quality ratings assigned by the bond rating agencies, such as Moody's Investors Service, Inc. and Standard & Poor's Corporation. Obligations of the United States Treasury are usually considered to be free of default risk, and hence reflect only the real rate of interest, compensation for expected inflation, and maturity

risk. The Treasury has been issuing inflation-indexed notes which automatically provide compensation to investors for future inflation, thereby providing a lower current yield on these issues.

Interest Rate Environment

Federal Reserve Board ("Fed") policy actions which impact directly short-term interest rates also substantially affect investor sentiment in long-term fixed-income securities markets. In this regard, the Fed has often pursued policies designed to build investor confidence in the fixed-income securities market. Formative Fed policy has had a long history, as exemplified by the historic 1951 Treasury-Federal Reserve Accord, and more recently, deregulation within the financial system which increased the level and volatility of interest rates. The Fed has indicated that it will follow a monetary policy designed to promote noninflationary economic growth.

As background to the recent levels of interest rates, history shows that the Open Market Committee of the Federal Reserve board ("FOMC") began a series of moves toward lower short-term interest rates in mid-1990 -- at the outset of the previous recession. Monetary policy was influenced at that time by (i) steps taken to reduce the federal budget deficit, (ii) slowing economic growth, (iii) rising unemployment, and (iv) measures intended to avoid a credit crunch. Thereafter, the Federal government initiated several bold proposals to deal with future borrowings by the Treasury. With lower expected federal budget deficits and reduced Treasury borrowings, together with limitations on the supply of new 30-year Treasury bonds, long-term interest rates declined to a twenty-year low, reaching a trough of 5.78% in October 1993.

On February 4, 1994, the FOMC began a series of increases in the Fed Funds rate (i.e., the interest rate on excess overnight bank reserves). The initial increase represented the first

rise in short-term interest rates in five years. The series of seven increases doubled the Fed Funds rate to 6%. The increases in short-term interest rates also caused long-term rates to move up, continuing a trend which began in the fourth quarter of 1993. The cyclical peak in long-term interest rates was reached on November 7 and 14, 1994 when 30-year Treasury bonds attained an 8.16% yield. Thereafter, long-term Treasury bond yields generally declined.

Beginning in mid-February 1996, long-term interest rates moved upward from their previous lows. After initially reaching a level of 6.75% on March 15, 1996, long-term interest rates continued to climb and reached a peak of 7.19% on July 5 and 8, 1996. For the period leading up to the 1996 Presidential election, long-term Treasury bonds generally traded within this range. After the election, interest rates moderated, returning to a level somewhat below the previous trading range. Thereafter, in December 1996, interest rates returned to a range of 6.5% to 7.0% which existed for much of 1996.

On March 25, 1997, the FOMC decided to tighten monetary conditions through a one-quarter percentage point increase in the Fed Funds rate. This tightening increased the Fed Funds rate to 5.5%. In making this move, the FOMC stated that it was concerned by persistent strength of demand in the economy, which it feared would increase the risk of inflationary imbalances that could eventually interfere with the long economic expansion.

In the fourth quarter of 1997, the yields on Treasury bonds began to decline rapidly in response to an increase in demand for Treasury securities caused by a flight to safety triggered by the currency and stock market crisis in Asia. Liquidity provided by the Treasury market makes these bonds an attractive investment in times of crisis. This is because Treasury securities encompass a very large market which provides ease of trading and carry a premium

for safety. During the fourth quarter of 1997, Treasury bond yields pierced the psychologically important 6% level for the first time since 1993.

Through the first half of 1998, the yields on long-term Treasury bonds fluctuated within a range of about 5.6% to 6.1% reflecting their attractiveness and safety. In the third quarter of 1998, there was further deterioration of investor confidence in global financial markets. This loss of confidence followed the moratorium (i.e., default) by Russia on its sovereign debt and fears associated with problems in Latin America. While not significant to the global economy in the aggregate, the August 17 default by Russia had a significant negative impact on investor confidence, following earlier discontent surrounding the crisis in Asia. These events subsequently led to a general pull back of risk-taking as displayed by banks growing reluctance to lend, worries of an expanding credit crunch, lower stock prices, and higher yields on bonds of riskier companies. These events contributed to the failure of the hedge fund, Long-Term Capital Management.

In response to these events, the FOMC cut the Fed Funds rate just prior to the mid-term Congressional elections. The FOMC's action was based upon concerns over how increasing weakness in foreign economies would affect the U.S. economy. As recently as July 1998, the FOMC had been more concerned about fighting inflation than the state of the economy. The initial rate cut was the first of three reductions by the FOMC. Thereafter, the yield on long-term Treasury bonds reached a 30-year low of 4.70% on October 5, 1998. Long-term Treasury yields below 5% had not been seen since 1967. Unlike the first rate cut that was widely anticipated, the second rate reduction by the FOMC was a surprise to the markets. A third reduction in short-term interest rates occurred in November 1998 when the FOMC reduced the Fed Funds rate to 4.75%.

All of these events prompted an increase in the prices for Treasury bonds which lead to the low yields described above. Another factor that contributed to the decline in yields on long-term Treasury bonds was a reduction in the supply of new Treasury issues coming to market due to the Federal budget surplus -- the first in nearly 30 years. The dollar amount of Treasury bonds being issued declined by 30% in two years thus resulting in higher prices and lower yields. In addition, rumors of some struggling hedge funds unwinding their positions further added to the gains in Treasury bond prices.

The financial crisis that spread from Asia to Russia and to Latin America pushed nervous investors from stocks into Treasury bonds, thus increasing demand for bonds, just when supply was shrinking. There was also a move from corporate bonds to Treasury bonds to take advantage of appreciation in the Treasury market. This resulted in a certain amount of exuberance for Treasury bond investments that formerly was reserved for the stock market. Moreover, yields in the fourth quarter of 1998 became extremely volatile as shown by Treasury yields that fell from 5.10% on September 29 to 4.70 percent on October 5, and thereafter returned to 5.10% on October 13. A decline and rebound of 40 basis points in Treasury yields in a two-week time frame is remarkable.

Beginning in mid-1999, the FOMC raised interest rates on six occasions reversing its actions in the fall of 1998. On June 30, 1999, August 24, 1999, November 16, 1999, February 2, 2000, March 21, 2000, and May 16, 2000, the FOMC raised the Fed Funds rate to 6.50%. This brought the Fed Funds rate to its highest level since 1991, and was 175 basis points higher than the level that occurred at the height of the Asian currency and stock market crisis. At the time, these actions were taken in response to more normally functioning financial markets, tight

labor markets, and a reversal of the monetary ease that was required earlier in response to the global financial market turmoil.

As the year 2000 drew to a close, economic activity slowed and consumer confidence began to weaken. In two steps at the beginning and at the end of January 2001, the FOMC reduced the Fed Funds rate by one percentage point. These actions brought the Fed Funds rate to 5.50%. The FOMC described its actions as "a rapid and forceful response of monetary policy" to eroding consumer and business confidence exemplified by weaker retail sales and business spending on capital equipment and cut backs in manufacturing production. Subsequently, on March 20, 2001, April 18, 2001, May 15, 2001, June 27, 2001, and August 21, 2001, the FOMC lowered the Fed Funds in steps consisting of three 50 basis points decrements followed by two 25 basis points decrements. These actions took the Fed Funds rate to 3.50%. The FOMC observed on August 21, 2001:

> "Household demand has been sustained, but business profits and capital spending continue to weaken and growth abroad is slowing, weighing on the U.S. economy. The associated easing of pressures on labor and product markets is expected to keep inflation contained.
>
> Although long-term prospects for productivity growth and the economy remain favorable, the Committee continues to believe that against the background of its long-run goals of price stability and sustainable economic growth and of the information currently available, the risks are weighted mainly toward conditions that may generate economic weakness in the foreseeable future."

After the terrorist attack on September 11, 2001, the FOMC made two additional 50 basis points reductions in the Fed Funds rate. The first reduction occurred on September 17, 2001 and followed the four-day closure of the financial markets following the terrorist attacks. The second reduction occurred at the October 2 meeting of the FOMC where it observed:

> "The terrorist attacks have significantly heightened uncertainty in an economy that was already weak. Business and household spending as a consequence are being further damped. Nonetheless, the long-term prospects for productivity growth and the economy remain favorable and should become evident once the unusual forces restraining demand abate."

Afterward, the FOMC reduced the Fed Funds rate by 50 basis points on November 6, 2001 and by 25 basis points on December 11, 2001. In total, short-term interest rates were reduced by the FOMC eleven (11) times during the year 2001. These actions cut the Fed Funds rate by 4.75% and resulted in 1.75% for the Fed Funds rate.

In an attempt to deal with weakening fundamentals in the economy recovering from the recession that began in March 2001, the FOMC provided a psychologically important one-half percentage point reduction in the federal funds rate. The rate cut was twice as large as the market expected, and brought the fed funds rate to 1.25% on November 6, 2002. The FOMC stated that:

> "The Committee continues to believe that an accommodative stance of monetary policy, coupled with still-robust underlying growth in productivity, is providing important ongoing support to economic activity. However, incoming economic data have tended to confirm that greater uncertainty, in part attributable to heightened geopolitical risks, is currently inhibiting spending, production, and employment. Inflation and inflation expectations remain well contained.
>
> In these circumstances, the Committee believes that today's additional monetary easing should prove helpful as the economy works its way through this current soft spot. With this action, the Committee believes that, against the background of its long-run goals of price stability and sustainable economic growth and of the information currently available, the risks are balanced with respect to the prospects for both goals in the foreseeable future."

As 2003 unfolded, there was a continuing expectation of lower yields on Treasury securities. In fact, the yield on ten-year Treasury notes reached a 45-year low near the end of

the second quarter of 2003. For long-term Treasury bonds, those yields culminated with a 4.24% yield on June 13, 2003. Soon thereafter, the FOMC reduced the Fed Funds rate by 25 basis points on June 25, 2003. In announcing its action, the FOMC stated:

> "The Committee continues to believe that an accommodative stance of monetary policy, coupled with still robust underlying growth in productivity, is providing important ongoing support to economic activity. Recent signs point to a firming in spending, markedly improved financial conditions, and labor and product markets that are stabilizing. The economy, nonetheless, has yet to exhibit sustainable growth. With inflationary expectations subdued, the Committee judged that a slightly more expansive monetary policy would add further support for an economy which it expects to improve over time."

Thereafter, intermediate and long-term Treasury yields moved marketedly higher. Higher yields on long-term Treasury bonds, which exceeded 5.00% can be traced to: (i) the market's disappointment that the Fed Funds rate was not reduced below 1.00%, (ii) an indication that the Fed will not use unconventional methods for implementing monetary policy, (iii) growing confidence in a strengthening economy, and (iv) a Federal budget deficit that is projected to be $455 billion in 2003 (reported subsequently, the actual deficit was $374 billion) and $475 billion in 2004 (revised subsequently, the estimated deficit is $500 billion in 2004). All these factors significantly changed the seniment in the bond market.

For the remainder of 2003, the FOMC continued with its balanced monetary policy, thereby retaining the 1% Fed Funds rate. However, in 2004, the FOMC initiated a policy of moving toward a more neutral Fed Funds rate (i.e., removing the bias of abnormal low rates). On June 30, 2004, August 10, 2004, September 21, 2004, November 10, 2004, December 14, 2004, February 2, 2005, March 22, 2005, May 3, 2005, June 30, 2005, August 9, 2005, September 20, 2005, November 1, 2005, December 13, 2005, January 31, 2006, March 28,

2006, May 10, 2006, and June 29, 2006, the FOMC increased the Fed Funds rate in seventeen 25 basis point increments. These policy actions are widely interpreted as part of the process of moving toward a more neutral range for the Fed Funds rate. In its January 31, 2007 press release, the FOMC stated:

> "Recent indicators have suggested somewhat firmer economic growth, and some tentative signs of stabilization have appeared in the housing market. Overall, the economy seems likely to expand at a moderate pace over coming quarters.
>
> Readings on core inflation have improved modestly in recent months, and inflation pressures seem likely to moderate over time. However, the high level of resource utilization has the potential to sustain inflation pressures.
>
> The Committee judges that some inflation risks remain. The extent and timing of any additional firming that may be needed to address these risks will depend on the evolution of the outlook for both inflation and economic growth, as implied by incoming information."

Public Utility Bond Yields

The Risk Premium analysis of the cost of equity is represented by the combination of a firm's borrowing rate for long-term debt capital plus a premium that is required to reflect the additional risk associated with the equity of a firm as explained in Appendix G. Due to the senior nature of the long-term debt of a firm, its cost is lower than the cost of equity due to the prior claim which lenders have on the earnings and assets of a corporation.

As a generalization, all interest rates track to varying degrees of the benchmark yields established by the market for Treasury securities. Public utility bond yields usually reflect the underlying Treasury yield associated with a given maturity plus a spread to reflect the specific credit quality of the issuing public utility. Market sentiment can also have an influence on the spreads as described below. The spread in the yields on public utility bonds and Treasury

bonds varies with market conditions, as does the relative level of interest rates at varying maturities shown by the yield curve.

Pages 1 and 2 of Schedule 11 provide the recent history of long-term public utility bond yields for the rating categories of Aa, A and Baa (no yields are shown for Aaa rated public utility bonds because this index has been discontinued). The top four rating categories of Aaa, Aa, A and Baa are known as "investment grades" and are generally regarded as eligible for bank investments under commercial banking regulations. These investment grades are distinguished from "junk" bonds which have ratings of Ba and below.

A relatively long history of the spread between the yields on long-term A-rated public utility bonds and 20-year Treasury bonds is shown on page 3 of Schedule 11. There, it is shown that those spreads were at about the one percentage point during the years 1994 through 1997. With the aversion to risk and flight to quality described earlier, a significant widening of the spread in the yields between corporate (e.g., public utility) and Treasury bonds developed in 1998, after an initial widening of the spread that began in the fourth quarter of 1997. The significant widening of spreads in 1998 was unexpected by some technically savvy investors, as shown by the debacle at the Long-Term Capital Management hedge fund. When Russia defaulted its debt on August 17, some investors had to cover short positions when Treasury prices spiked upward. Short covering by investors that guessed wrong on the relationship between corporate and Treasury bonds also contributed to run-up in Treasury bond prices by increasing the demand for them. This helped to contribute to a widening of the spreads between corporate and Treasury bonds.

As shown on page 3 of Schedule 11, the spread in yields between A-rated public utility bonds and 20-year Treasury bonds were about one percentage point prior to 1998, 1.32% in

1998, 1.42% in 1999, 2.01% in 2000, 2.13% in 2001, 1.94% in 2002, 1.62% in 2003, 1.12% in 2004, 1.01% in 2005 and 1.08% in 2006. As shown by the monthly data presented on pages 4 and 5 of Schedule 11, the interest rate spread between the yields on 20-year Treasury bonds and A-rated public utility bonds was 1.07 percentage points for the twelve-months ended January 2007. For the six- and three-month periods ending January 2007, the yield spread was 1.05% and 1.02%, respectively.

Risk-Free Rate of Return in the CAPM

Regarding the risk-free rate of return (see Appendix H), pages 2 and 3 of Schedule 13 provide the yields on the broad spectrum of Treasury Notes and Bonds. Some practitioners of the CAPM would advocate the use of short-term treasury yields (and some would argue for the yields on 91-day Treasury Bills). Other advocates of the CAPM would advocate the use of longer-term treasury yields as the best measure of a risk-free rate of return. As Ibbotson has indicated:

> The Cost of Capital in a Regulatory Environment. When discounting cash flows projected over a long period, it is necessary to discount them by a long-term cost of capital. Additionally, regulatory processes for setting rates often specify or suggest that the desired rate of return for a regulated firm is that which would allow the firm to attract and retain debt and equity capital over the long term. Thus, the long-term cost of capital is typically the appropriate cost of capital to use in regulated ratesetting. (Stocks, Bonds, Bills and Inflation - 1992 Yearbook, pages 118-119)

As indicated above, long-term Treasury bond yields represent the correct measure of the risk-free rate of return in the traditional CAPM. Very short term yields on Treasury bills should be avoided for several reasons. First, rates should be set on the basis of financial conditions that will exist during the effective period of the proposed rates. Second, 91-day Treasury bill yields are more volatile than longer-term yields and are greatly influenced by FOMC monetary policy,

political, and economic situations. Moreover, Treasury bill yields have been shown to be empirically inadequate for the CAPM. Some advocates of the theory would argue that the risk-free rate of return in the CAPM should be derived from quality long-term corporate bonds.

RISK PREMIUM ANALYSIS

The cost of equity requires recognition of the risk premium required by common equities over long-term corporate bond yields. In the case of senior capital, a company contracts for the use of long-term debt capital at a stated coupon rate for a specific period of time and in the case of preferred stock capital at a stated dividend rate, usually with provision for redemption through sinking fund requirements. In the case of senior capital, the cost rate is known with a high degree of certainty because the payment for use of this capital is a contractual obligation, and the future schedule of payments is known. In essence, the investor-expected cost of senior capital is equal to the realized return over the entire term of the issue, absent default.

The cost of equity, on the other hand, is not fixed, but rather varies with investor perception of the risk associated with the common stock. Because no precise measurement exists as to the cost of equity, informed judgment must be exercised through a study of various market factors which motivate investors to purchase common stock. In the case of common equity, the realized return rate may vary significantly from the expected cost rate due to the uncertainty associated with earnings on common equity. This uncertainty highlights the added risk of a common equity investment.

As one would expect from traditional risk and return relationships, the cost of equity is affected by expected interest rates. As noted in Appendix F, yields on long-term corporate bonds traditionally consist of a real rate of return without regard to inflation, an increment to reflect investor perception of expected future inflation, the investment horizon shown by the term of the issue until maturity, and the credit risk associated with each rating category.

The Risk Premium approach recognizes the required compensation for the more risky common equity over the less risky secured debt position of a lender. The cost of equity stated in terms of the familiar risk premium approach is:

$$k=i+RP$$

where, the cost of equity *("k")* is equal to the interest rate on long-term corporate debt *("i")*, plus an equity risk premium *("RP")* which represents the additional compensation for the riskier common equity.

Equity Risk Premium

The equity risk premium is determined as the difference in the rate of return on debt capital and the rate of return on common equity. Because the common equity holder has only a residual claim on earnings and assets, there is no assurance that achieved returns on common equities will equal expected returns. This is quite different from returns on bonds, where the investor realizes the expected return during the entire holding period, absent default. It is for this reason that common equities are always more risky than senior debt securities. There are investment strategies available to bond portfolio managers that immunize bond returns against fluctuations in interest rates because bonds are redeemed through sinking funds or at maturity, whereas no such redemption is mandated for public utility common equities.

It is well recognized that the expected return on more risky investments will exceed the required yield on less risky investments. Neither the possibility of default on a bond nor the maturity risk detracts from the risk analysis, because the common equity risk rate differential (i.e., the investor-required risk premium) is always greater than the return components on a bond. It should also be noted that the investment horizon is typically long-run for both corporate debt and equity, and that the risk of default (i.e., corporate bankruptcy) is a concern

to both debt and equity investors. Thus, the required yield on a bond provides a benchmark or starting point with which to track and measure the cost rate of common equity capital. There is no need to segment the bond yield according to its components, because it is the total return demanded by investors that is important for determining the risk rate differential for common equity. This is because the complete bond yield provides the basis to determine the differential, and as such, consistency requires that the computed differential must be applied to the complete bond yield when applying the risk premium approach. To apply the risk rate differential to a partial bond yield would result in a misspecification of the cost of equity because the computed differential was initially determined by reference to the entire bond return.

The risk rate differential between the cost of equity and the yield on long-term corporate bonds can be determined by reference to a comparison of holding period returns (here defined as one year) computed over long time spans. This analysis assumes that over long periods of time investors' expectations are on average consistent with rates of return actually achieved. Accordingly, historical holding period returns must not be analyzed over an unduly short period because near-term realized results may not have fulfilled investors' expectations. Moreover, specific past period results may not be representative of investment fundamentals expected for the future. This is especially apparent when the holding period returns include negative returns which are not representative of either investor requirements of the past or investor expectations for the future. The short-run phenomenon of unexpected returns (either positive or negative) demonstrates that an unduly short historical period would not adequately support a risk premium analysis. It is important to distinguish between investors' motivation to invest, which encompass positive return expectations, and the knowledge that losses can occur. No rational

investor would forego payment for the use of capital, or expect loss of principal, as a basis for investing. Investors will hold cash rather than invest with the expectation of a loss.

Within these constraints, page 1 of Schedule 12 provides the historical holding period returns for the S&P Public Utility Index which has been independently computed and the historical holding period returns for the S&P Composite Index which have been reported in Stocks, Bonds, Bills and Inflation published by Ibbotson & Associates. The tabulation begins with 1928 because January 1928 is the earliest monthly dividend yield for the S&P Public Utility Index. I have considered all reliable data for this study to avoid the introduction of a particular bias to the results. The measurement of the common equity return rate differential is based upon actual capital market performance using realized results. As a consequence, the underlying data for this risk premium approach can be analyzed with a high degree of precision. Informed professional judgment is required only to interpret the results of this study, but not to quantify the component variables.

The risk rate differentials for all equities, as measured by the S&P Composite, are established by reference to long-term corporate bonds. For public utilities, the risk rate differentials are computed with the S&P Public Utilities as compared with public utility bonds.

The measurement procedure used to identify the risk rate differentials consisted of arithmetic means, geometric means, and medians for each series. Measures of the central tendency of the results from the historical periods provide the best indication of representative rates of return. In regulated ratesetting, the correct measure of the equity risk premium is the arithmetic mean because a utility must expect to earn its cost of capital in each year in order to provide investors with their long-term expectations. In other contexts, such as pension determinations, compound rates of return, as shown by the geometric means, may be

appropriate. The median returns are also appropriate in ratesetting because they are a measure of the central tendency of a single period rate of return. Median values have also been considered in this analysis because they provide a return which divides the entire series of annual returns in half and are representative of a return that symbolizes, in a meaningful way, the central tendency of all annual returns contained within the analysis period. Medians are regularly included in many investor-influencing publications.

As previously noted, the arithmetic mean provides the appropriate point estimate of the risk premium. As further explained in Appendix H, the long-term cost of capital in rate cases requires the use of the arithmetic means. To supplement my analysis, I have also used the rates of return taken from the geometric mean and median for each series to provide the bounds of the range to measure the risk rate differentials. This further analysis shows that when selecting the midpoint from a range established with the geometric means and medians, the arithmetic mean is indeed a reasonable measure for the long-term cost of capital. For the years 1928 through 2006, on a preliminary basis, the risk premiums for each class of equity are:

	S&P Composite	S&P Public Utilities
Arithmetic Mean	5.86%	5.41%
Geometric Mean	4.25%	3.35%
Median	10.17%	7.29%
Midpoint of Range	7.21%	5.32%
Average	6.54%	5.37%

The empirical evidence suggests that the common equity risk premium is higher for the S&P Composite Index compared to the S&P Public Utilities.

If, however, specific historical periods were also analyzed in order to match more closely historical fundamentals with current expectations, the results provided on page 2 of Schedule 12 should also be considered. One of these sub-periods included the 55-year period, 1952-2006. These years follow the historic 1951 Treasury-Federal Reserve Accord which affected monetary policy and the market for government securities.

A further investigation was undertaken to determine whether realignment has taken place subsequent to the historic 1973 Arab Oil embargo and during the deregulation of the financial markets. In each case, the public utility risk premiums were computed by using the arithmetic mean, and the geometric means and medians to establish the range shown by those values. The time periods covering the more recent periods 1974 through 2006 and 1979 through 2006 contain events subsequent to the initial oil shock and the advent of monetarism as Fed policy, respectively. For the 55-year, 33-year and 28-year periods, the public utility risk premiums were 6.40%, 5.61%, and 5.83% respectively, as shown by the average of the specific point-estimates and the midpoint of the ranges provided on page 2 of Schedule 12.

CAPITAL ASSET PRICING MODEL

Modern portfolio theory provides a theoretical explanation of expected returns on portfolios of securities. The Capital Asset Pricing Model ("CAPM") attempts to describe the way prices of individual securities are determined in efficient markets where information is freely available and is reflected instantaneously in security prices. The CAPM states that the expected rate of return on a security is determined by a risk-free rate of return plus a risk premium which is proportional to the non-diversifiable (or systematic) risk of a security.

The CAPM theory has several unique assumptions that are not common to most other methods used to measure the cost of equity. As with other market-based approaches, the CAPM is an expectational concept. There has been significant academic research conducted that found that the empirical market line, based upon historical data, has a less steep slope and higher intercept than the theoretical market line of the CAPM. For equities with a beta less than 1.0, such as utility common stocks, the CAPM theoretical market line will underestimate the realistic expectation of investors in comparison with the empirical market line which shows that the CAPM may potentially misspecify investors' required return.

The CAPM considers changing market fundamentals in a portfolio context. The balance of the investment risk, or that characterized as unsystematic, must be diversified. Some argue that diversifiable (unsystematic) risk is unimportant to investors. But this contention is not completely justified because the business and financial risk of an individual company, including regulatory risk, are widely discussed within the investment community and therefore influence investors in regulated firms. In addition, I note that the CAPM assumes that through portfolio diversification, investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Because it is not known whether the average

investor holds a well-diversified portfolio, the CAPM must also be used with other models of the cost of equity.

To apply the traditional CAPM theory, three inputs are required: the beta coefficient *("β")*, a risk-free rate of return *("Rf")*, and a market premium *("Rm - Rf")*. The cost of equity stated in terms of the CAPM is:

$$k = Rf + \beta (Rm - Rf)$$

As previously indicated, it is important to recognize that the academic research has shown that the security market line was flatter than that predicted by the CAPM theory and it had a higher intercept than the risk-free rate. These tests indicated that for portfolios with betas less than 1.0, the traditional CAPM would understate the return for such stocks. Likewise, for portfolios with betas above 1.0, these companies had lower returns than indicated by the traditional CAPM theory. Once again, CAPM assumes that through portfolio diversification investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Therefore, the CAPM must also be used with other models of the cost of equity, especially when it is not known whether the average public utility investor holds a well-diversified portfolio.

Beta

The beta coefficient is a statistical measure which attempts to identify the non-diversifiable (systematic) risk of an individual security and measures the sensitivity of rates of return on a particular security with general market movements. Under the CAPM theory, a security that has a beta of 1.0 should theoretically provide a rate of return equal to the return rate provided by the market. When employing stock price changes in the derivation of beta, a stock with a beta of 1.0 should exhibit a movement in price which would track the movements

in the overall market prices of stocks. Hence, if a particular investment has a beta of 1.0, a one percent increase in the return on the market will result, on average, in a one percent increase in the return on the particular investment. An investment which has a beta less than 1.0 is considered to be less risky than the market.

The beta coefficient *("β")*, the one input in the CAPM application which specifically applies to an individual firm, is derived from a statistical application which regresses the returns on an individual security (dependent variable) with the returns on the market as a whole (independent variable). The beta coefficients for utility companies typically describe a small proportion of the total investment risk because the coefficients of determination (R^2) are low.

Page 1 of Schedule 13 provides the betas published by Value Line. By way of explanation, the Value Line beta coefficient is derived from a "straight regression" based upon the percentage change in the weekly price of common stock and the percentage change weekly of the New York Stock Exchange Composite average using a five-year period. The raw historical beta is adjusted by Value Line for the measurement effect resulting in overestimates in high beta stocks and underestimates in low beta stocks. Value Line then rounds its betas to the nearest .05 increment. Value Line does not consider dividends in the computation of its betas.

Market Premium

The final element necessary to apply the CAPM is the market premium. The market premium by definition is the rate of return on the total market less the risk-free rate of return *("Rm - Rf")*. In this regard, the market premium in the CAPM has been calculated from the total return on the market of equities using forecast and historical data. The future market return is

established with forecasts by Value Line using estimated dividend yields and capital appreciation potential.

With regard to the forecast data, I have relied upon the Value Line forecasts of capital appreciation and the dividend yield on the 1,700 stocks in the Value Line Survey. According to the January 19, 2007, edition of The Value Line Investment Survey Summary and Index, (see page 5 of Schedule 13) the total return on the universe of Value Line equities is:

	Dividend Yield	+	Median Appreciation Potential	=	Median Total Return
As of January 19, 2007	1.7%	+	8.78%[1]	=	10.48%

The tabulation shown above provides the dividend yield and capital gains yield of the companies followed by Value Line. Another measure of the total market return is provided by the DCF return on the S&P 500 Composite index. As shown below, that return is 12.89%.

DCF Result for the S&P 500 Composite

D/P		1+.5g		+	g	=	k
1.72%	(	1.05535	)	+	11.07%	=	12.89%

where:	Price (P)	at	31-Dec-2006	= 1418.30
	Dividend (D)	for	3rd Qtr '06	= 6.09
	Dividend (D)		annualized	= 24.36
	Growth (g)		First Call EpS	= 11.07%

Using these indicators, the total market return is 11.69% (10.48% + 12.89% = 23.37% ÷ 2) using both the Value Line and S&P derived returns. With the 11.69% forecast market return and the 5.25% risk-free rate of return, a 6.44% (11.69% - 5.25%) market premium would be indicated using forecast market data.

With regard to the historical data, I provided the rates of return from long-term

[1] The estimated median appreciation potential is forecast to be 40% for 3 to 5 years hence. The annual capital gains yield at the midpoint of the forecast period is 8.78% (i.e., $1.40^{.25} - 1$).

historical time periods that have been widely circulated among the investment and academic community over the past several years, as shown on page 6 of Schedule 13. These data are published by Ibbotson Associates in its Stocks, Bonds, Bills and Inflation ("SBBI"). From the data provided on page 6 of Schedule 13, I calculate a market premium using the common stock arithmetic mean returns of 12.3% less government bond arithmetic mean returns of 5.8%. For the period 1926-2006, the market premium was 6.5% (12.3% - 5.8%).

I should note that the arithmetic mean must be used in the CAPM because it is a single period model. It is further confirmed by Ibbotson who has indicated:

> *Arithmetic Versus Geometric Differences*
> For use as the expected equity risk premium in the CAPM, the *arithmetic* or *simple difference* of the *arithmetic* means of stock market returns and riskless rates is the relevant number. This is because the CAPM is an additive model where the cost of capital is the sum of its parts. Therefore, the CAPM expected equity risk premium must be derived by arithmetic, *not geometric*, subtraction.
>
> *Arithmetic Versus Geometric Means*
> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values. This makes the arithmetic mean return appropriate for computing the cost of capital. The discount rate that equates expected (mean) future values with the present value of an investment is that investment's cost of capital. The logic of using the discount rate as the cost of capital is reinforced by noting that investors will discount their (mean) ending wealth values from an investment back to the present using the arithmetic mean, for the reason given above. They will therefore require such an expected (mean) return prospectively (that is, in the present looking toward the future) to commit their capital to the investment. (Stocks, Bonds, Bills and Inflation - 1996 Yearbook, pages 153-154)

For the CAPM, a market premium of 6.47% (6.5% + 6.44% = 12.94% ÷ 2) would be

reasonable which is the average of the 6.5% using historical data and a market premium of 6.44% using forecasts.

COMPARABLE EARNINGS APPROACH

Value Line's analysis of the companies that it follows includes a wide range of financial and market variables, including nine items that provide ratings for each company. From these nine items, one category has been removed dealing with industry performance because, under approach employed, the particular business type is not significant. In addition, two categories have been ignored that deal with estimates of current earnings and dividends because they are not useful for comparative purposes. The remaining six categories provide relevant measures to establish comparability. The definitions for each of the six criteria (from the Value Line Investment Survey - Subscriber Guide) follow:

Timeliness Rank

> The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

> A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating an ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to

market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00072155

PPL Electric Utilities Corporation

Statement No. 12

Direct Testimony of Julie M. Cannell

I. INTRODUCTION

Q. Please state your name, employer, and business address.

A. My name is Julie M. Cannell. I am the president of my own advisory firm, J.M. Cannell, Inc. My business address is P.O. Box 199, Purchase, NY 10577.

Q. Please describe your professional and educational background.

A. My firm, J.M. Cannell, Inc., provides advisory services to electric utility companies and other firms and organizations with an interest in the industry. Prior to establishing my firm in February 1997, I was employed by the New York-based investment manager, Lord Abbett & Company, from June 1978 to January 31, 1997. During my tenure with Lord Abbett, I was a securities analyst specializing in the electric utility and telecommunications services industries; portfolio manager of America's Utility Fund, an equity utility mutual fund, for which Lord Abbett was a subadvisor; portfolio manager of numerous institutional equity portfolios; and co-director of Lord Abbett's Equity Research Department. Further information on my background can be found in Appendix A.

Q. Have you submitted testimony previously before any state regulatory agencies?

A. Yes, I have. In addition to Pennsylvania, I have submitted pre-filed testimony on behalf of investor-owned utilities before Public Service or Public Utility Commissions in the states of Arizona, Kansas, Missouri, Nevada, Oklahoma, South Carolina, Texas, Virginia, and Washington.

Q. What is the scope of your testimony in this proceeding?

A. I have been asked by the Company to discuss the perspective of investors with respect to the return on equity for PPL Electric Utilities Corporation ("PPL Electric" or the "Company") in the context of the current rate case.

Q. As an analyst or portfolio manager, did you follow PPL Corporation?

A. Yes, I did. Both Lord Abbett and America's Utility Fund periodically maintained a holding in the common stock of PPL Corp. ("PPL"), which was then named Pennsylvania Power & Light Company.

Q. Please summarize the key points of your testimony.

A. As my testimony will explain, investors now require a higher return when investing in the electric industry due to the changing nature of the industry through a hybrid deregulated structure and attendant increased risk. The investment industry itself has undergone major changes in recent years, including a dramatic growth in the amount of capital controlled by institutional investors and hedge funds. Performance pressures have shortened significantly the timeframe during which an investment must realize its expected return.

In making their assessments of utility companies, credit rating agencies and investors consider various factors, key among them the regulatory environment. Regulators influence a utility's capital structure and returns that may be earned on that capital. Those factors in turn determine a company's creditworthiness, as well as its ability to provide stable earnings and dividends. The credit rating agencies generally are positive on PPL Electric at this time due, at least in part, to their perceptions of a constructive regulatory climate in Pennsylvania. At the same time, the credit rating agencies have sounded various

cautionary notes related to the need for strong investment spending, as well as the risks attendant in the post-POLR period in the state. Security analysts have expressed both an awareness of the current case, as well as concerns about power procurement policies in the post-transition to competition period. The latter factor is an additional risk factor in their outlook.

In my judgment, the investment community would find an 11.5% return on equity for the Company to be reasonable. Such a return level would provide PPL Electric with the necessary cash flow to continue to maintain its strong credit quality and also meet the expectations of equity investors. Importantly, an 11.5% ROE would benefit customers by strengthening the Company's finances and lowering its future cost of capital.

Q. Please summarize what in your experience allows you to provide testimony about the viewpoint of investors.

A. As a securities analyst, I specialized in the electric utility industry and the individual companies comprising it. And as a portfolio manager, I applied that knowledge, along with investment fundamentals, toward investment decisions on behalf of institutions and individual investors. Moreover, I have reviewed the various reports of analysts and rating agencies, which have addressed the Company and its regulatory situation.

Q. Please describe how your testimony is organized.

A. There are three parts to my testimony.

How Investors Evaluate Investments in Utility Companies. This section discusses why investors choose to invest in electric utilities, with particular

emphasis on why the regulatory climate in which the utility operates is of such importance to investors. This section of the testimony also discusses why the risk of investing in the electric utility industry has risen substantially in recent years on an industry-wide basis, and why markets today react so swiftly and strongly to unfavorable news about a company. It further details the risk present in distribution-only companies.

Investors' Perceptions Related to the Present Proceeding. This section reviews the investment community's perceptions of PPL Electric and Pennsylvania regulation. This review is based on a number of recent publications by credit rating agencies and investment analysts discussing their perceptions of the rate case and the Company's regulatory environment.

Return on Equity. This section discusses PPL Electric's request for an 11.5% return on equity, which will be addressed in greater detail in the direct testimony supported by Mr. Paul Moul. My conclusion is that the Company's proposal is one that investors view as important and constructive. An allowed ROE of 11.5% would lead to a more robust stream of earnings and cash flow, and would be viewed favorably by rating agencies and the investment community at a time when increased financial stability is very important to the Company.

II. HOW INVESTORS EVALUTE INVESTMENTS IN UTILITY COMPANIES

Q. Why is it important to consider the opinions of the investment community?

A. Investors provide the capital necessary to maintain and expand the Company's infrastructure, which in turn enables PPL Electric to provide reliable service to customers. The terms on which the Company is able to obtain that capital have a direct and measurable impact on ratepayers and the amounts they pay for delivery service. For example, if credit rating agencies such as Moody's, S&P, or Fitch believe that the utility's revenues will be diminished by adverse business or regulatory decisions, those rating agencies would lower their credit ratings for the utility, which would raise the cost of debt. And, because the cost of debt is a component of the weighted average cost of capital, the increased costs of capital would be passed on to ratepayers in the form of higher rates.

The same is true for equity investors. If individual or institutional investors believe that the return they are offered is too low in light of the risk involved, they will either sell their stock or elect not to purchase the stock, which generally drives the stock price down. Although lower stock prices would appear at first blush to be a concern only to investors, they also affect ratepayers. When a utility has to go to the equity markets to obtain capital, a low stock price requires it to issue more shares of stock to obtain the same amount of money that it would have received for fewer shares if the per share price had been higher. Because of the resulting increase in the number of shares outstanding, more dollars would have to be expended toward dividends, resulting in less retained earnings for reinvestment in the company.

The corollary is that when investors believe that they are investing in a company that enjoys fair, consistent regulation and a reasonable rate of return,

those investors charge less for their capital. And when debt and equity investors demand less for their capital, utility rates remain lower and utilities have more ready access to the capital markets. Thus, a utility and its ratepayers have a shared interest in meeting the expectations of investors and credit rating agencies. Regulators share this interest as well, because fair treatment of one utility decreases the costs of capital for all utilities in that regulatory jurisdiction.

Q. Are you suggesting that the Pennsylvania Public Utility Commission should cater to the desires of investors?

A. No. I realize that the Pennsylvania Public Utility Commission ("PUC" or "Commission") has to balance the interests of both investors, who want consistent and constructive regulatory treatment, and ratepayers, who want lower rates. My point is that the Commission's decision on rate of return is not simply a zero-sum game. If the rate of return is within a zone of reasonableness, both the utility and ratepayers win. If the rate of return is set too low, both the utility and ratepayers lose because of the effect on the cost of capital. The PUC's December 2004 decision for PPL Electric was emblematic of fairly balancing the interests of investors and ratepayers. At the time of that decision, a 10.7% ROE on a 47% equity ratio, while at the low end of a reasonable range, was viewed by investors as constructive. Within the context of the PUC's ruling, the equity return treatment was considered to be reasonably supportive, given the current cost of capital. I note that the cost of capital is a function of market risks and the risks borne by PPL Electric, and thus can change over time. The next part of my

testimony is devoted to explaining why the correlation of investor and shareholder interests exists.

Q. What goals lead investors to invest in electric utilities?

A. Historically, electric utilities have been regarded as investment vehicles that provide stable performance through the ups and downs of market cycles and changing economic conditions. Electric utilities historically have earned a reasonable return even when conditions were not favorable for other companies. Accordingly, electric utility stocks have been particularly valuable holdings when conditions were not favorable to investments in more volatile industry sectors. In other words, investors might see greater returns from investment in other industries when times were good, but they would lose less on electric utility stocks when times were less favorable.

In addition, the reliability of electric utilities' earnings streams historically has permitted most of the companies to continue to pay regular dividends during both good and bad economic cycles. For investors with a need for regular cash income, the prospect of regular dividends has been an important consideration in making a decision to invest in electric utility stocks

Based on these factors, investors traditionally have viewed electric utility stocks as bond substitutes. In other words, electric utility stocks have provided regular cash returns in the form of dividends and the shares themselves were seen to have a stable underlying value. Electric utilities historically have paid out a large proportion of their earnings as dividends, and their large construction programs have kept them dependent on the capital markets. As a result, electric

utility stocks as a group have tended to move closely in line with the direction of interest rates, but in an inverse relationship. That is, utility stock prices rose when interest rates fell, and vice versa. These factors made electric utilities a preferred investment during economic slowdowns or recessions and owning them was a way of balancing the risks in a stock portfolio that included stocks in more volatile industries.

Q. Have the recent changes in the industry increased the risk of investing in electric utilities?

A. Yes. Investors now understand that the predictability of the electric utility industry's earnings, across the sector, has been undermined by the restructuring that has taken place in many parts of the country, including Pennsylvania. These risks are in addition to the risks posed by technological, economic, environmental and other policy changes that affect the industry. These increased risks mean that investors no longer perceive electric utilities as a group as being the "safe havens" they once were.

Investors' goals, however, have not fundamentally changed. They still look to electric utilities primarily as defensive investments, and still look for stable performance and regular dividends as the reason to invest in electric utilities. But investors also understand that the investment risk in electric stocks has risen significantly, and that there is more risk than before that could serve to frustrate investors' goals for investing in this sector.

In the end, investors have a very large universe of stocks from which to select; with few exceptions, they have no requirement to own electric utility

stocks. Consequently, investors now require a higher return for investing in the electric utility industry to balance the increased risk associated with it.

Q. How do these concerns affect PPL Electric?

A. Markets tend to make judgments about investment risks that apply to industry sectors as a whole. Company-specific risk factors are additive to sector risk. In other words, investors first determine the risk involved in investing in a particular sector. They then add to that sector risk the specific risks applicable to individual companies.

Q. Does PPL Electric face additional risks in a competitive market for energy?

A. Yes, it does. When the Company was an integrated utility involved in the broad provision of generation, transmission, and distribution services, PPL Electric was able to spread the risks involved in any of those businesses across a broader base. However, as a wires-only company now, focusing on energy delivery, PPL Electric has all of its assets concentrated in a single line of business and thus is fully exposed to any risks, including those pertaining to size and scope, that may impact its core business. In addition, PPL Electric can no longer control the cost of power to the customer, because of deregulation. This creates a greater risk that it will not be able to respond to competitive-imposed pressures.

Q. Are there other risks?

A. Yes. Another set of risks pertain to advances in technology. One such issue is distributed generation, which is a technology that permits power to be generated on small-scale machines that can be sited near a manufacturing facility, in a commercial business, or even a residence. Micro-grids that currently are

proposed for the state are an example of such machines. Distributed generation potentially can have a serious adverse impact on a utility's delivery system because distributed generation can facilitate bypass of the system. To the extent that customers see distributed generation as a means of controlling their price, reliability and power quality, even in areas where the utility (such as PPL Electric) provides high reliability and quality, they may choose distributed generation in an effort to take more of their operations under their own control.

Q. Do rising electric prices create risks that the Company will face increased competition to maintain its distribution customers?

A. Yes. That risk is heightened as rate caps expire. As will be discussed later in my testimony, the post-POLR period beginning January 1, 2010 is well within investors' current investment horizon. At that point, the Company could be vulnerable to a myriad of new risks related to the formation of micro-grids, as detailed in Mr. Krall's testimony. As explained by Mr. Krall, micro-grids—a small power generation and distribution network directly serving multiple customers with an electric generating facility located near or on the same site as the consumer—could have a number of unintended negative impacts on the Company. These can include: cannibalizing the Company's highest load customers and forcing the loss of significant revenues; making operations and investments less efficient due to a decreasing average load factor; and requiring PPL Electric to sell standby power at the lowest reasonable cost. The extent of the risk from micro-grids would depend largely on factors beyond the utility's control, but it could prove to be substantial.

Q. What other risks do you see technology posing to wires-only utilities?

A. The advances in technology have made some industries less dependent on geography. There will be continuing pressure to retain customers who can relocate out of the utility's service area or who can take actions that are equivalent to relocation. Manufacturers and commercial businesses can choose to relocate to other parts of a state, or to other states or regions. Bypass may increasingly become economic for these customers, as well as customers who do not wish to or cannot move. There will be pressure to discount prices to retain these customers. PPL Electric no longer controls the cost of power and may not be able to discount enough to compete. Furthermore, the effect of lost customers is exacerbated for the Company because it is a much smaller company after generation divestiture. The Company simply has fewer units over which to spread its fixed costs.

Q. What additional risk factors are facing wires-only companies today?

A. The past year has seen a rise in disruptive activity in state legislatures, particularly those in the states of Illinois and Maryland, related to the expiration of price caps imposed under a restructured regulatory scheme. High commodity prices have also contributed to a reluctance on the part of politicians and regulators to subject consumer to additional rate increases. In Pennsylvania, PPL Electric's rate caps will be expiring at the end of 2009, and investors are very focused on this fact. While PPL Electric and other utilities in the state have made proposals to the PUC for mitigating the impact of price cap expiration on customers and the PUC itself has initiated proceedings to seek solutions for the issue, there is no guarantee that the negative action occurring in other states will not surface in Pennsylvania. As

noted previously, the potential for micro-grids to exist from 2010 forward could impose a significant risk on PPL Electric and other distribution utilities in the state.

A related factor is rising environmental requirements coupled with a significantly heightened public awareness of climate issues, making the prospect of legislation with mandatory compliance requirements and attendant higher expenditures within the near future more likely. Even though PPL Electric does not own generation, it would bear the expenses associated with environmental compliance—particularly because Pennsylvania is a deregulated state—through the costs it pays for POLR power, which would factor in higher environmental-related power production expenses.

Q. Have further risks related to wires-only companies presented themselves?

A. Yes. A number of factors are converging to suggest there will be more regular rate cases, which raise questions about a utility's cash flow recovery. Such proceedings will be driven by such items as rising medical costs and pension expenses and increased capital investment in utility infrastructure.

Q. You've discussed the mounting risks you see a distribution company facing. Do those risks have the potential to reduce the company's earnings and cash flow streams and increase their volatility?

A. Yes. A single line of business increases exposures to enterprise credit risk, operating issues, prospective new costs, and technology issues, all of which can have negative financial ramifications. Moreover, because these factors are in large part beyond a company's control, the company's investors have little

guidance and more uncertainty. Uncertainty leads to investor concern and demands for higher investment returns.

Q. Please turn now to utility regulation. Why is the perception of regulatory climate of such importance to investors?

A. Equity investors today are still seeking companies that can offer stability in earnings and dividends. Fixed income investors look for stable and adequate cash flows to ensure payment of principal and interest when due, as indicated by stable credit ratings. The ability to pay dividends and sustain credit ratings is directly related to the consistency and sufficiency of a utility's earnings, which depend in large part on how the utility is regulated. If there is uncertainty about whether regulation will allow a utility the opportunity to earn a reasonable return in future years, then that uncertainty will lead investors to avoid holding investment positions in the utility, all other things being equal.

As a result, I believe that investors selecting electric utility stocks today place a very high value on consistent and constructive regulation. And, with a new round of base rate case filings underway in the industry, I think it likely that the quality of regulation will receive renewed investor attention.

Q. In your experience as an analyst and portfolio manager, could a perceived change in a company's regulatory climate affect your investment opinion?

A. Absolutely. During my tenure as an active investor, a company's regulatory environment was a critical factor in my assessment of its investment attractiveness. An adverse regulatory decision could be a key determinant in my

recommendation or decision to sell a stock already owned or not to make an investment in one under consideration.

Q. Who are typical investors in utility stocks?

A. There are two kinds of investors: individuals, who generally seek stability and income from their utility holdings, and institutions, which generally seek total return (i.e., price appreciation plus dividend income) from their utility investments.

Q. How has the investment industry itself changed in recent years?

A. In recent years, institutional investors and hedge funds have grown dramatically in the amount of capital they control. This growth has had a significant impact on the speed with which the market reacts to unfavorable developments. It has led the market to be much more reactive and much less forgiving than it may have been in the past. In the context of a regulatory decision, investors will not necessarily wait, as they would have in the past, to see how the ramifications of a decision might play out. Rather, they simply sell their shares if a regulator's decision runs counter to their expectations.

Q. What has led to that change in the market's reaction?

A. The market is now heavily populated by institutional investors, who play a significant role in the marketplace.

Q. Why are institutional investors of such importance generally?

A. Because of the sheer size of their investment positions, institutions can effectively direct the course of individual securities, and sometimes can move the market as a whole. Institutional investors include financial institutions such as: mutual funds,

investment companies, insurance companies, commercial and investment banks, and various types of public retirement funds. They approach the investment selection process from the standpoint of a portfolio. An investment portfolio is a collection of stocks selected to achieve the highest possible return within a commensurate level of risk. Therefore, institutional investors keep electric utilities in their portfolios only when such stocks contribute to achieving the desired risk/return relationship.

It should be remembered that, generally, the customers of institutional investors are individuals and it is they who ultimately gain or suffer loss from changes in the value of the institution's investments. Anyone who has a stake in a retirement plan, owns a mutual fund, or has a trust fund, for example, is directly or indirectly a client of an institutional investor. But the individuals who make the decisions concerning these investments are paid money managers, and how they see their responsibilities to the clients they serve, and the way that their performance is judged, have a great deal to do with how they react to developments in the market.

Q. Why are institutional investors important to PPL Electric and PPL?

A. Institutional investors today hold roughly 63% of PPL's total common shares. Such investors warrant significant attention because they can dramatically change the market for PPL shares. Because institutional investors own large blocks of shares relative to the volumes typically traded, their activity in moving in or out of the company's shares is often noticeable as a significant change in the price and volume of shares being traded for the company. This change may be picked

up by other institutional investors, by the investment community in general, and eventually by individual investors. These other entities will then look to see what is driving this trend in the stock and whether the trend is likely to continue or disappear. If they see support for the trend, they may follow the lead of the firms that initially began to move the market, and by following the leaders, the late movers may further strengthen the trend.

Q. Why might an institutional investor choose not to hold investments in a particular electric utility?

A. Several factors might be drivers. First, institutional investors have fiduciary responsibilities. For example, managers of pension assets fall under Federal ERISA laws, which mandate that a portfolio manager's decisions meet the so-called "prudent man" standard. That is to say, he or she is expected not to make investment decisions that are unduly risky or to retain stocks that are unduly risky given the investment goals of the portfolio and the function of the stock within it.

In addition, institutional investors have performance pressures. It is not enough for stocks in a portfolio simply to increase in value. Rather, relative performance is what counts. Investment performance is gauged against the returns earned by a market proxy (such as the Standard & Poor's 500 Index) or a peer group of investments (i.e., those with a similar style, such as value, growth, growth & income, small cap, etc.). Mutual fund rating organizations such as Morningstar track and publicize the relative performance for mutual funds, while various pension consultants perform the same service for their client organizations.

Q. What happens when an institutional investor underperforms?

A. The results can vary, but, eventually, underperformance will result in lost business and personnel changes. Mutual fund shareholders can sell their fund shares. A pension plan sponsor can fire the professional investor or reduce the assets under their investor's management. And, of course, poor performance also disadvantages the individual who has entrusted his monies to the institution for management.

Q. How long a period does an institutional investor have before performance becomes an issue?

A. Again, it can vary. But there is little argument that institutional investors no longer have the luxury of a long time horizon in which to show performance. Investors want results. And, with the public visibility that investment results now have (through organizations such as Morningstar and the various pension consultants) and the resulting performance pressure, most investment organizations are now operating with a much shorter time horizon than in years past. Generally speaking, a long investment time horizon today can be as short as 12-18 months. So, a stock that is unlikely to perform within the prescribed time horizon is usually not attractive for purchase or continued investment by an institutional investor.

Q. What does this mean for investments in regulated utilities specifically?

A. This shortened time frame means that if there is bad news, institutional investors are more likely to react quickly. In the instance of a rate proceeding, these investors are unlikely to wait to see what the outcome of the next rate decision

will be. That would represent an opportunity cost to them. Rather, institutional investors would be more prone to sell their shares on the news of an adverse regulatory outcome. This would not be good for ratepayers either, for the reasons discussed earlier.

Q. Do all institutional investors function within the time frames you describe?

A. No. There is a type of institutional investor called a hedge fund that frequently buys and sells the same stock during the course of a day.

Q. What impact do hedge funds have on the market in general and stocks in particular?

A. Their impact can be dramatic. Hedge funds are well known for trading in information; their actions are frequently event-driven. Sometimes that information is factual and other times it falls into the category of rumor. Because investors at hedge funds have wide information networks and are in frequent communication with companies and a broad range of other investors, they have the ability and the power to create volatility, which in turn impacts the movement of stock prices. The number of hedge funds participating in the market and the funds' assets have grown exponentially in recent years—recent estimates put the numbers at over 9000 firms with assets of $1.225 trillion globally in mid-2006, with the top 150 U.S. hedge funds' assets at almost $500 billion, compared to 610 firms with $39 billion in assets in 1990. Thus, they have become a very strong force both in the market and in stocks in which they are interested. When they like an industry group or a stock, hedge funds can provide substantial support to stock prices. But, conversely, when they become disenchanted, their tendency is

to sell quickly and without remorse. Although their focus is not on contributing to orderly markets, hedge funds are a formidable presence in the market place and must be reckoned with.

Q. Can you give an example of how hedge funds might traffic in PPL's stock?

A. Yes. Investors have been aware of the current proceeding for several months. Hedge funds assuredly made assumptions about the details of the case, including its resolution, prior to the filing. If, when the PUC's decision is ultimately announced, the details fall short of those expectations, the hedge funds could put significant pressure on the stock either through outright sales, or short-selling (i.e., selling stock that is borrowed in anticipation that the price of the stock will drop before the borrowed stock must be replaced). Hedge funds seek to get ahead of the broader market and react to news before the market can. Accordingly, if hedge funds decide to make moves on PPL's shares based on the order in this proceeding, they will begin to do so within hours of the release of the order. The presence of such funds also can serve to attract like-minded hedge funds to join forces into a herd mentality that can prove a highly disruptive force.

Q. What role do credit agencies play in investors' expectations?

A. In the wake of financial disasters, bankruptcies, and the ensuing severe erosion in investor confidence in the past few years, credit issues have become critically important not only to fixed income investors, but also to equity investors. While credit downgrades initially impacted only the most troubled companies, a spillover effect soon was seen on healthy utilities. Part of this was due to the fact that the rating agencies came under harsh criticism that they had failed to catch

problems early enough in companies such as Enron Corp. As a result, they began to heighten their scrutiny of all entities under their watch and became far more proactive in making rating changes. As well, "headline risk" began to come into play, as investors worried that –when credit problems in an industry are in the headlines—any company in the sector could be vulnerable to a downgrade. Thus, equity investors now closely watch the actions of the credit agencies, because any change in ratings can have a significant impact on a company's stock price.

Q. What happens when a credit downgrade occurs?

A. In the simplest terms, it becomes more expensive for a company to raise money in the capital markets because a downgrade raises a company's risk profile and consequently, increases the cost of debt. And because of the increased linkage these days between ratings and stock prices, the price frequently reacts—sometimes quite strongly—to a downgrade. It should be noted that both negative and positive changes in credit ratings can and do occur as a result of regulatory actions. Following the PUC's December 2004 rate decision for PPL Electric, for example, the Company was upgraded by Moody's and S&P raised its ratings outlook on the Company to "Stable" from "Negative." The agencies advised, however, that the PUC needed to continue its constructive treatment of the Company for the new rating levels to be maintained.

III. INVESTORS' PERCEPTIONS OF THE CURRENT PROCEEDING

Q. Why is it important to consider the opinions of the investment community?

A. Suffice it to say, investors provide the capital necessary to maintain and expand the Company's infrastructure, which in turn enables PPL Electric to provide reliable service to its customers. Perceptions of the investment community matter. The availability and cost of necessary funding ultimately impacts the Company's customers.

Q. How have you gauged investors' perceptions of the issues in this proceeding?

A. To supplement my own knowledge of the industry, I have reviewed various reports related to PPL and PPL Electric written by the credit rating agencies and investment analysts. A clear picture of investors' perceptions emerges from these reports, which is in keeping with my own views.

Q. Which credit agency reports have you reviewed?

A. I have examined reports written by Moody's, Standard & Poor's, and Fitch Ratings, which are the three key credit rating agencies.

Q. Why is a utility's regulatory environment important in general to the rating agencies?

A. The rating agencies appraise companies on the basis of creditworthiness. They evaluate current financial soundness and attempt to discern how that might change in the future. One of the key factors in assessing a utility's financial picture is the regulatory climate in which the company operates, because regulators influence the utility's capital structure and establish allowed returns that may be earned on that capital. Thus, a regulatory environment characterized by consistency and predictability is one that lends itself to a company's having a

sounder financial base. Conversely, a regulatory situation defined by a lack of stability can have a deleterious impact on a utility's credit profile.

Q. How do the rating agencies view PPL Electric and its regulatory situation?

A. All three agencies view the utility constructively, but separately offer various cautionary notes.

Q. Please elaborate.

A. In a March 2006 report, Moody's raised PPL Electric's senior secured debt rating to A3 from Baa1, with a stable outlook, along with the ratings for sister company PPL Capital Funding. PPL and the other subsidiaries were maintained at their respective current levels. Among the factors the agency cited for its upgrades were:

> "1) Expectations for higher earnings and cash flow over the next three years;
> 2) The generally constructive regulatory situation for PPL EU, which includes a pass through of generation-based energy costs related to its long-term, full-requirements power supply agreements that enable PPL EU to meet its obligations as a POLR provider over the 2006-2009 period;
> 3) Moderate expected growth in the volume of energy deliveries, which supports the expected stability of cash flows from regulated operations until the end of the regulatory transition period in 2009."[1]

Elaborating on its upgrade of PPL Electric, Moody's noted that it had "considered the risk that the utility may need to seek large rate increases in 2010," and assumed that "regulatory treatment will provide for reasonably timely recovery of increased costs and expenditures."[2] In discussing the utility's credit strengths, the agency pointed to the fact that PPL Electric "operates in a reasonable regulatory climate," and "Supply and price risk is virtually eliminated by its Provider of Last

[1] Moody's Investors Service, Credit Opinion: PPL Electric Utilities Corporation," March 31, 2006.
[2] Ibid.

Resort or 'all requirements' contract through December 31, 2009 that has been approved by the Pennsylvania Public Utility Commission."[3] Moody's also considers PPL Electric to have credit challenges, which include a "higher level of planned capex over the next several years" and "the company is committed to improving its financial performance.[4]

Q. What is Fitch Ratings' opinion of the Company?

A. The agency, which carries an A- stable rating on PPL Electric's secured bonds, provided a credit update on the Company last August. Like Moody's, Fitch characterized its ratings as reflecting:

> "...the low risk of PPL Electric Utilities Corporation's (PPLEU) regulated electric distribution operations and a sound financial profile. The low business risk assessment primarily reflects a full-requirements electricity supply contract with affiliate PPL EnergyPlus, LLC (PPL EnergyPlus) and a constructive regulatory environment.[5]

The agency said the current ratings "assume the cost of procuring power to meet PPL Electric's POLR obligations after 2009 will be passed through to customers," and noted the Company's August 2006 proposal to the PUC for such procurement.[6]

Q. How does Standard & Poor's view PPL Electric?

A. As does Fitch, S&P has an "A- stable" rating on the Company's secured debt. As a PPL Electric "Strength," the agency cited the December 2004 rate case decision which "provides support to credit quality through the ability to recover all power and transmission costs," while a weakness in S&P's view is "uncertainty about

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[3] Ibid.
[4] Ibid.
[5] Fitch Ratings, "Credit Update: PPL Electric Utilities Corporation," August 28, 2006.
[6] Ibid.

competitive markets in Pennsylvania after the transition plan expires."[7] Elaborating on the previous rate decision, the agency pointed to its benefiting the Company's credit profile, with a 10.7% allowed ROE. S&P said, "The rate increase has resulted in an improvement in the past 18 months. For the 12 months ended Sept. 30, 2006, credit measures were satisfactory for the rating."[8] While duly acknowledging the strengthening in PPL Electric's financial profile, S&P also cautioned "If credit-protection measures weaken, however, the outlook may be revised to negative, and the ratings subsequently lowered."[9]

Q. What conclusion do you draw from the rating agencies' reports?

A. The agencies are universally positive on PPL Electric due, at least in part, to their perceptions of a constructive regulatory climate in Pennsylvania and evidenced by positive credit actions following the supportive ROE award in the Company's December 2004 rate order. But cautionary notes were sounded. Moody's is concerned about the high level of capital expenditures facing the Company in the context of a commitment to improving financial performance. Fitch, in basing its current ratings on the assumption that post-2009 power procurement costs will be passed through to customers, silently raises the question that such a circumstance isn't certain. S&P pointed to the uncertainty surrounding the post-2009 period as a weakness in its ratings of PPL Electric and warned that weakening credit protection measures could result in a downgrade.

[7] Standard & Poor's, PPL Electric Utilities Corp.," November 16, 2006.
[8] Ibid.
[9] Ibid.

Q. *Please turn your attention now to the thoughts of security analysts regarding PPL Electric. What are their opinions about the Company's regulatory circumstances?*

A. Several investors have commented on the prospects for a PPL Electric rate case.

Lehman Brothers notes:

> PPL Electric utilities [sic] will file a rate case in March '07 for a test year ending September '06, new rates from this case would be effective beginning in 2008 and this is embedded in PPL's indicative '08 guidance.[10]

Wachovia Securities also commented on the case:

> PPL Electric Utilities plans to file a base rate case with the Pennsylvania PUC in late March 2007 to cover higher costs attributable to personnel, poles, wire and equipment necessary to distribute electricity. The company indicated that it expects the rate increase request to be less than its 7.1% increase that was effective January 1, 2005. In that case, the company received a total annual revenue increase of $194MM, roughly $57MM of which was tied to an increase in PJM-related transmission charges.[11]

Additional mention of the pending filing was made by Dahlman Rose:

> Delivery EPS should benefit from a distribution rate increase expected in January 2008. The company intends to file for a delivery rate increase in March 2007. If the company was earning only 7.5% ROE at year-end 2006 (data not yet available), it may file for a $90m rate increase, and may receive about $60m in additional revenues—which would add about $0.10 to EPS when offset by normal attrition.[12]

Further reference to the case came from A.G. Edwards:

> PPL Electric is preparing to file for a distribution rate increase to be effective at the beginning of 2008. The requested increase is expected to be modest and is needed to recover rising operating and capital costs. During the 12-month period ended 9/30/2006, PPL Electric's distribution operations earned an 8.1% ROE. This compares with an authorized ROE

[10] Lehman Brothers, "PPL Corporation, Steady as she goes, awaiting PUC Action," February 1, 2007.
[11] Wachovia Capital Markets, "PPL Corporation, PPL: Downgrading Rating to Market Perform; Valuation, Regulatory Uncertainty, Modest EPS Growth," February 1, 2007.
[12] Dahlman Rose & Co., "PPL Corporation: PPL Stays the Course with 14% CAGR," February 5, 2006.

of 10.7%, established in a late 2004 PUC rate order. We expect a rate increase would have a modest $0.04-$0.06 impact on annual EOS, which is reflected in our 2008 estimate.[13]

Q. Did the analysts' discussion of the rate filing focus on associated regulatory risk?

A. No. I believe that there are several reasons for that. First, the case had not been filed at the time of the reports' publication. Second, investors' regulatory focus in Pennsylvania already had turned to the post-POLR period in the state.

Q. Please elaborate on the latter.

A. Analysts are acutely aware of the fact that PPL Electric's fixed price contract for power supply with PPL EnergyPlus expires at the end of 2009, raising the specter of considerable financial uncertainty from 2010 forward. While PPL Electric filed a proposal in August 2006 for a "bridge" power procurement plan for 2010, and a PUC Administrative Law Judge in late February recommended that the Commission adopt the scheme, no resolution in the matter has yet occurred. Even if the plan is approved by the PUC—and it could occur during the course of these proceedings— uncertainty remains present for 2011, as the proposal covers 2010 only. In the analysts' words:

> We believe that PPL will remain range bound in the near term while execution of the scrubber program, plant performance, up-rates, and regulatory treatment of the roll off of POLR pricing to competitive pricing in '10/11+ remain catalysts that could provide upside to the story provided there is positive resolution. . . . The biggest uncertainty surrounding PPL is the transition from POLR regulated below market rates to market rates, or some other regulated scheme in 2010 and 2011+. . . . We view the PA PUC as constructive with regards toward competitive markets. As these regulatory matters become resolved we believe the earnings picture in

[13] A.G. Edwards, "PPL Corporation," February 1, 2007.

2010+ for PPL will crystallize, providing the market with a clearer view of PPL's out year earnings. [Lehman Brothers][14]

A decision is expected shortly from the Pennsylvania PUC on PPL's proposed transition plan – a favorable outcome would reduce lingering political and regulatory concerns related to PA's upcoming transition to a competitive market. [A.G. Edwards][15]

Q. What implications does investors' post-2009 focus have on this rate case?

A. The fact that the investment community already is paying attention to the post-POLR period suggests an added element of risk and uncertainty is now present in a PPL Electric investment. Although power procurement from 2010 forward is several years away, analysts already are considering what ramifications this will have on PPL's earnings power; investors provide capital today with the expectations of future returns. Accordingly, the existence of this uncertainty will make investors require a higher return to compensate for their assuming this additional risk.

Q. Did the analysts also convey their expectations for a return on equity award in the rate case?

A. No, but that is not surprising because the reports were written prior to the case being filed. However, given the fact that the Company is perceived now to have an added layer of risk that was not immediately present in the last rate case, I believe that the absolute floor that would be considered acceptable to investors would be the 10.7% ROE that the PUC awarded in 2004.

Q. Does that imply that investors expect an ROE allowance of 10.7%?

[14] Lehman Brothers, op. cit.
[15] A.G. Edwards, op. cit.

A. No. That is simply the minimum level that I believe investors would find to be acceptable. In addition to the concerns that investors have about the post-POLR period for PPL Electric, they also have some unease about the supportiveness of regulation in the current climate of rising energy prices, and thus would likely err on the side of conservatism (i.e., the low end of the expected allowed range) in anticipating the rate case's outcome.

Indeed, this regulatory uncertainty also is reflected in Lehman Brothers' 2006 ranking of state utility commissions from an investor perspective. The firm rated Pennsylvania "Tier 4" on a 5-tiered scale, with Tier 1 being "Most Shareholder Oriented" and Tier 5 being "Most Consumer Oriented." Lehman's rankings were based on 6 criteria: 1) elected versus appointed commissions; 2) performance-based ratemaking mechanism or not; 3) allowed ROEs; 4) settlements versus litigation 5) rate levels; and 6) a subjective investor friendless rating.[16] It also bears mention that in Lehman's 2004 regulatory study, Pennsylvania regulation was assigned a "2" rating, one of eight states at that level, which reinforces the concept of additional uncertainty at the present time.[17] As well, a lower rating has negative implications for all utilities in the state, as, all other things being equal, the cost of capital associated with a utility investment in a state with a more regulatory-friendly investment climate would be less than in one that is viewed as less constructive.

Q. Did Lehman comment further on ROE awards in general?

[16] Lehman Brothers, "Capital Lessons," March 15, 2006.
[17] Lehman Brothers, "They're Back! Twenty-Six Rate Cases This Year Give Rise to the Regulators," March 5, 2004.

A. Yes. The firm presented projections for annual allowed returns on equity for the industry for 2006 through 2010. Lehman is estimating an 11.30% average ROE award. The firm notes, however, that "Primarily because of regulatory lag and increased financing expenses, utilities suffer subpar returns during periods of heavy capital investment."

Q. What are the implications of Lehman's industry ROE analysis for PPL Electric?

A. Lehman is projecting an 11.3% average allowed ROE for the industry over each of the next five years. That projection would reinforce the likelihood that a 10.7% ROE is conservative. Mr. Moul's recommendation of an 11.25%-11.75% ROE range and recommendation of 11.5% is consistent with Lehman's 11.3% ROE.

Q. Are there additional inferences to be drawn from investors' views of the Company?

A. Yes. One of the key factors analysts use to evaluate the quality of a regulatory climate is the consistency of a commission's decisions. Investors value certainty and predictability; a lack of consistency in a commission's decisions serves to increase the investment risk associated with a utility. With an unpredictable track record of regulatory decisions, investors are unable to anticipate reliably the future actions of a commission. That in turn depresses valuations—i.e., lowers the price of a stock and increases a company's cost of borrowing. In a study I prepared last year for the Edison Electric Institute on investors' perceptions of state regulation, respondents were asked to cite the regulatory factors they felt characterized a constructive environment, as well as a non-constructive

environment. On the positive side of the ledger, one of the top set of factors was a regulatory climate that is "fair, stable, predictable, and consistent." The top factor cited by the respondents as characterizing a non-constructive environment was a climate that is "arbitrary, inconsistent, and unwilling to acknowledge the economic realities that utilities face." One investor summed up that type of non-constructive regulation as "regulatory purgatory."[18]

Q. Have other comments than those in the previously cited reports been made about the quality of Pennsylvania regulation?

A. Yes. Following the PUC's December 2004 decision in PPL Electric's rate case, a number of analysts wrote reports on the outcome. Merrill Lynch, citing as the reason for its report "Constructive Outcomes to PA and UK Rate Cases," noted "The Pennsylvania rate case outcome is more favorable than the ALJ recommendation, which was for a 10.25% ROE and a slightly lower equity ratio. The rate increase will represent a substantial improvement to the utility's current low single-digit ROE."[19] Lehman Brothers also opined, in a report entitled "Good Rate Outcomes Point to Stronger EPS," that "PPL has reached constructive rate outcomes in both PA and the UK . . ."[20] The investment community viewed the PUC's 10.7% ROE award in the Company's prior rate case as constructive in the context of the entire rate order. The Commission will need to follow up that supportive ROE action in the present proceeding.

[18] J.M. Cannell, Inc., "State Utility Regulation: An Assessment of Investor Perceptions," August 2005.
[19] Merrill Lynch, "PPL Corp.: Rate Cases Wrapped Up," December 3, 2004.
[20] Lehman Brothers, "PPL Corp.: Change of Earnings Forecast: Good Rate Outcomes Point to Stronger EPS," December 14, 2004.

Q. Yet you mentioned earlier that Lehman's ranking of Pennsylvania regulation from an investor perspective was lowered from a "2" to a "4" on the firm's 1-5 scale after the last PPL Electric rate decision. How do you account for that negative change?

A. Other than publishing the criteria used to derive their rankings in general, Lehman does not explain the rationale behind its individual state assessments. However, some of those criteria might shed some light on the altered rankings: performance based ratemaking mechanisms or not, and allowed ROEs. While many states do have some form of performance-based ratemaking ("PBR"), i.e. incentives, Pennsylvania does not. PBR is positive from an investor perspective because it provides a utility management with the opportunity to improve financial performance and share those benefits with ratepayers; conversely, if a management fails to meet agreed-upon standards or measures, no reward is granted, and often a financial penalty is assessed. In other words, the onus rests on management to run the business more efficiently and capture additional earnings in the process. An additional factor that might explain Lehman's change of ranking is allowed ROEs. While investors applauded the PUC's permitting PPL Electric an ROE in excess of that recommended by the ALJ in the previous rate case and was considered a positive step as evidenced by S&P's credit analysis, the fact is that the Company has not been able to earn at the allowed level. Additionally, while the 10.7% award was, indeed, an improvement over the ALJ recommendation, it was below the average 10.91% authorized in the fourth quarter of 2004 for a total of eight electric cases nationwide during that period,

according to statistics compiled by research firm Regulatory Research Associates ("RRA").[21] As well, PPL Electric's 10.7% ROE was awarded within the context of data in an historical, rather than a projected, test year, which makes it difficult—if not impossible—for the Company to earn at allowed levels. Because investors consider companies on a comparative basis, the fact is, other utilities that were potential investments presented an opportunity for earning higher returns on an equity investment.

Q. Does RRA offer an evaluation of the quality of Pennsylvania regulation?

A. Yes. The firm provides a ranking of the regulatory climates of 49 states and the District of Columbia. According to RRA:

> The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by the jurisdiction's electric, gas, and telephone utilities. Each evaluation is based upon our studies of the numerous factors affecting the regulatory process in the state, and is changed as major events occur which cause us to modify our view of the regulatory risk accruing to the ownership of utility securities in that individual jurisdiction. We also review our evaluation when we issue State Regulatory Reviews, and when we publish quarterly comparative evaluations. The majority of factors that we consider are discussed in *Focus Notes*, State Regulatory Reviews, Final Reports, or Regulatory Updates. We also consider information obtained from contacts with commission, company, and government personnel in the course of our research. The final evaluation reflects our assessment of the probable level and quality of the earnings to be realized by the state's utilities as a result of regulatory, legislative, and court actions.[22]

There are three tiers to RRA's ranking scheme: Above Average, Average, and Below Average, with a numeric designation of 1, 2, or 3 within the principal rating category employed to indicate relative strength therein. Pennsylvania is accorded an "Average/3" ranking, which reflects the weakest segment or low end

[21] Regulatory Research Associates, "Major Rate Case Decisions—January 2005-December 2006; Supplemental Study," January 30, 2007.
[22] Regulatory Research Associates, "State Regulatory Evaluations," July 12, 2006.

of the Average tier. Although RRA's and Lehman's rating structures are not identical, it could be argued that the firms' assessment of Pennsylvania regulation is similar. According to RRA,

> The Pennsylvania regulatory climate continues to be relatively stable. The Commission and Legislature have been proactive in responding to changes in the electric, gas, and telecommunications industries. In implementing electric retail choice, the PUC adopted transition plans that at that time were, for the most part, considered constructive. ... However, the plans preclude the utilities from increasing prices during their company-specific transition periods to reflect rising costs associated with providing power to customers who decline to select an alternative supplier. ... it is unclear what the post-transition market will look like in the state. ... We continue to accord Pennsylvania regulation an Average/3 rating.[23]

Q. Have other investors offered opinion on regulatory quality in general?

A. Yes. Bank of America Securities publishes an annual study of regulation, in which it lists characteristics it believes comprise a state commission that is supportive of credit quality.[24] Although the list is extensive, the two top factors pertain to decisions that are supportive of credit quality and the authorized return on equity and equity ratios. Regarding the first factor, the firm notes that: "The commission consistently adopts regulatory policies and makes decisions that have the result of producing strong, stable cash flow and interest coverage."[25] As to equity returns and levels, Bank of America opines: "Higher authorized returns on equity and higher approved equity ratios used in setting the fair rate of return provide higher interest coverages for regulated utilities. It is our view that the utilities that have higher equity ratios than the industry average do so in large part because historically, their state commissions recognize the benefit and permit the

[23] Regulatory Research Associates, "Pennsylvania Regulatory Review—February 2007."
[24] Bank of America Securities, "Kaleidoscope of Power: Regulation in Focus," March 2005.
[25] Ibid.

companies to pass costs through rates."[26] While Bank of America Securities does not rank the various regulatory commissions, it does provide data on each to permit investors to draw their own conclusions.

Q. What inference do you draw from the various analysts' comments about the quality of regulation in general and Pennsylvania regulation in particular as they pertain to this regulatory proceeding?

A. In my opinion, investors—both equity and debt—would clearly view a PUC decision that is consistent with the Company's request to be reflective of the continuation of constructive regulation in Pennsylvania. The PUC demonstrated to investors in its December 2004 decision for PPL Electric that it would support utilities' need to invest significant levels of capital to maintain a strong and reliable electric infrastructure. For the PUC to deviate from that positive example in the current case would send a strong signal to investors that the quality of Pennsylvania regulation is inconsistent and not supportive of utilities' needs to access the capital markets.

IV. RETURN ON EQUITY FOR PPL ELECTRIC

Q. How do you believe that PPL Electric's requested return on equity of 11.5% comports with investors' perceptions?

A. I believe that the investment community would find an 11.5% ROE supportive for the company. It is consistent with investors' expectations for ROE allowances in 2006 for supportive jurisdictions.

[26] Ibid.

Q. Why do return on equity rewards vary among state commissions and companies?

A. As Mr. Moul's testimony sets forth, generic factors such as interest rates and industry issues contribute to a determination of return on equity, but in the final analysis, the appropriate ROE level is specific to the company in question. For example, as noted previously, PPL Electric has a number of risk factors relevant to a wires-only utility that increase its risk, coupled with company-specific issues, which should argue for a higher allowed ROE as compensation for that greater risk level.

Q. Please comment on Mr. Moul's ROE recommendation.

A. Mr. Moul notes that the cost of equity capital for the Company is within a range of 11.25% and 11.75%. Investment risk in the electric utility industry is higher than it has been, and investors are requiring greater levels of compensation to assume that added risk. As an input in valuation models, earnings levels logically translate into the attractiveness of a stock, other factors being equal. A reasonable ROE award should sustain the Company's earnings power and affect the potential for future dividend growth. Conversely, a lower ROE could potentially undermine investors' expectations for dividend sustainability.

Q. Could a return on equity award that is consistent with investor expectations also be expected to provide benefits to PPL Electric's customers?

A. Absolutely. A higher ROE permits the realization of a stronger earnings stream. In turn, that can improve a company's stock's valuation prospects, which results in a higher stock price. Thus, when a company needs to tap the equity markets for

capital needed to meet customer needs, it can get more for its money. Said another way, each share sold brings more equity into the Company with the same commitment by the Company to generate earnings and pay dividends to support the value of that share. In regard to debt financing, a higher ROE awarded to PPL Electric would be viewed as a sign of constructive regulation and would be positive for the Company's credit rating. Importantly, customers' rates will eventually reflect this lower cost of capital.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

Appendix A

JULIE M. CANNELL
P.O. Box 199
Purchase, New York 10577

BUSINESS EXPERIENCE:

1997- J.M. CANNELL, INC.

President of firm providing advisory services specializing in the electric utility industry.

1977 - 1997 LORD ABBETT & COMPANY, New York, New York

1995 - 1997 Equity Portfolio Manager. Responsibility for management and client servicing of ten institutional equity portfolios with total assets in excess of $700M. Actively and successfully involved in new institutional business marketing effort.

1994-1996 Associate Director of Equity Research. Provided oversight of departmental activities, including supervision of analysts' research efforts and support staff functions.

1992-1995 Portfolio Manager, America's Utility Fund. Full portfolio management responsibility for the fund since its May 1992 inception.

1978-1995 Securities Analyst. Sole responsibility for analysis of and stock recommendations for the electric utility and telecommunications industries. Other areas of coverage previously included housing (2 years) and pollution control (1 year).

Summer 1977 Research Assistant in Utilities.

1973-1976 UNIVERSITY OF COLORADO. Colorado Springs, Colorado.

Public Services Librarian
Instructor in Bibliography to undergraduate and M.B.A. students

1971-1973 CAMERON COLLEGE, Lawton, Oklahoma.

Reference Librarian

EDUCATION:

1978	COLUMBIA UNIVERSITY, MBA - Finance
1971	EMORY UNIVERSITY, M.Ln. - Librarianship
1970	MARY BALDWIN COLLEGE, B.A. - English

MEMBERSHIPS:

Chartered Financial Analyst (C.F.A.)
CFA Institute
New York Society of Security Analysts
Wall Street Utility Group

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00072155

PPL Electric Utilities Corporation

REBUTTAL TESTIMONY

Statement No. 2-R	Joseph R. Schadt
Statement No. 4-R	David R. Woodruff
Statement No. 5-R	Douglas A. Krall
Statement No. 6-R	Joseph M. Kleha
Statement No. 7-R	Oliver G. Kasper
Statement No. 8-R	Timothy R. Dahl
Statement No. 11-R	Paul R. Moul
Statement No. 12-R	Julie M. Cannell
Statement No. 13-R	Terry Novatnack

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00072155

PPL Electric Utilities Corporation

Statement No. 2-R

Rebuttal Testimony of Joseph R. Schadt

Rebuttal Testimony of Joseph R. Schadt

Q. Please state your name and business address.

A. My name is Joseph R. Schadt. My business address is PPL Services Corporation, Two North Ninth Street, Allentown, Pennsylvania, 18101.

Q. Did you previously submit testimony in this proceeding on behalf of PPL Electric Utilities Corporation?

A. Yes. I submitted my direct testimony, Statement No. 2, on March 29, 2007.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony primarily responds to the assertions of two witnesses. Mr. Lafayette Morgan, representing the Office of Consumer Advocate and Mr. Joseph Kubas, representing the Office of Trial Staff, on the following topics:

(I) the increase in miscellaneous revenue (responding to Mr. Morgan);

(II) the increase in late payment revenue (responding to Messrs. Kubas and Morgan);

(III) the increase in rent from electric property revenues (responding to Mr. Morgan);

(IV) the reduction to the claim for employee expenses (responding to Mr. Morgan);

(V) the reduction to the claim for telephone and leased wires expense (responding to Mr. Morgan);

(VI) the reduction to the claim for materials and supplies expense (responding to Mr. Morgan);

(VII) the reduction to the claim for pension expense (responding to Mr. Morgan);

(VIII) the reduction to the claim for postretirement benefits other than pension expense (responding to Mr. Morgan);

(IX) the reduction to the claim for property insurance (responding to Mr. Morgan);

(X) the reduction to the claim for negative net salvage (responding to Mr. Morgan); and,

(XI) the inclusion of a gain from the sale of property (responding to Mr. Kubas).

I. Miscellaneous Revenues

Q. Mr. Morgan recommends increasing future test year miscellaneous revenue by $369,000. This recommendation is based on the actual 2006 miscellaneous revenue recorded by PPL Electric, which Mr. Morgan believes is representative of future revenues of this type. The 2006 revenues primarily include fees for insufficient funds (NSF) and reconnection fees, revenue from temporary facilities, and commissions from an alliance agreement. Miscellaneous revenue was not included in the Company's budget projections because such revenues are not budgeted to occur every year. Do you agree with Mr. Morgan's proposed adjustment?

A. Yes. I accept Mr. Morgan's recommendation to include miscellaneous revenues in PPL Electric's 2007 test year. As a result, PPL Electric will increase miscellaneous revenue by $369,000 in the future test year, which is reflected on page 1 of Schedule D-3, Exhibit Future 1-Revised.

II. Late Payment Revenue

Q. Please describe the adjustments to forfeited discounts/late payment revenue proposed by Mr. Morgan and Mr. Kubas.

A. Mr. Morgan recommends an increase of $898,000 to the Company's forfeited discounts, also known as late payment revenue. This proposed adjustment is based on a 3-year weighted average of actual late payment revenue to electricity sales revenue for the period 2004 through 2006, as provided in the response to Question OTS-RE-32-D of Interrogatories of the Office of Trial Staff, Set IV, dated April 18, 2007.

Mr. Kubas recommends an increase of $507,000 to the Company's late payment revenue. Mr. Kubas also asserted that a 3-year weighted average of actual late payment revenue to electricity sales revenue for the period 2004 through 2006 be used. In his calculation Mr. Kubas used total electricity sales revenue for 2004 and 2005, which was included in the response to Question 3 of Interrogatories of the Office of Consumer Advocate, Set VII, dated June 1, 2007, and total operating revenue for 2006 as presented on Schedule D-3 of Exhibit Historic 1. Mr. Kubas then applied his calculated a 3-year weighted average to total operating revenue for 2007 as presented on Schedule D-3 of Exhibit Future 1.

Q. Do you agree with Mr. Morgan's proposed adjustment?

A. No. I agree with Mr. Morgan's recommendation to adjust late payment revenue to reflect the 3-year weighted average of actual late payment revenue to electricity sales revenue for the period 2004 through 2006. However, I do not agree with Mr. Morgan's calculation. The revenues presented in the response to Question OTS-RE-32-D of Interrogatories of the Office of Trial Staff, Set IV,

dated April 18, 2007, did not include revenues from the intangible transition charge. These revenues are included in total electricity sales revenue which is used to determine late payment revenue. As a result, Mr. Morgan's 3-year Forfeited Discount Ratio is overstated.

Q. Do you agree with Mr. Kubas' recommended adjustment?

A. No. I agree with Mr. Kubas' recommendation to adjust late payment revenue to reflect the 3-year weighted average of actual late payment revenue to revenue from electricity for the period 2004 through 2006. However, I do not agree with Mr. Kubas' calculation. Mr. Kubas used total operating revenues in 2006 as shown on Exhibit Historic 1 in his calculation of the 3-year weighted average. This is incorrect because late payment revenue is only applied to total electricity sales revenue. Mr. Kubas then applied this 3-year weighted average to total operating revenues in 2007 as shown on Exhibit Future 1. As a result, Mr. Kubas overstated both the 3-year weighted average and projected 2007 late payment revenue.

Q. Please describe your proposed adjustment.

A. Schedule 1 of Exhibit JRS 5 presents the calculation of the 3-year weighted average and the Company's recommended adjustment. This calculation uses total electricity sales revenue, which includes the intangible transition charge, as the basis of its 3-year weighted average and the derivation of proposed 2007 late payment revenue. The intangible transition charge should be

included in the calculation since it is a component of customer bills to which late payment revenues are applied. As shown on that schedule, PPL Electric is recommending an increase in late payment revenue of $339,000. This adjustment is reflected on page 1 of Schedule D-3, Exhibit Future 1-Revised.

III. Rent from Electric Property

Q. Mr. Morgan recommends an increase of $2,621,000 to the Company's Rent from Electric Property revenues. Mr. Morgan proposes this adjustment because PPL Electric's 2007 jurisdictional Rent from Electric Property revenues appeared to be decreasing in comparison to Rent from Electric Property for 2006. Mr. Morgan's adjustment is determined by applying the 2005-2006 revenue growth rate of 8.14% to adjusted 2006 distribution revenues from Rent from Electric Property. Do you agree with Mr. Morgan's proposed adjustment?

A. No, I do not agree with Mr. Morgan's adjustment. First, Mr. Morgan's comparison of Rent from Electric Property for 2006 and 2007 is flawed because the 2006 figure includes significant non-recurring revenues. In fact, there is an increase in PPL Electric's distribution Rent from Electric Property between 2006 and 2007 when 2006 revenues are adjusted for these non-recurring items. Second, Mr. Morgan arbitrarily applied the 2005-2006 revenue growth rate of 8.14% to adjusted 2006 Rent from Electric Property. Mr. Morgan stated that he used this growth rate because other growth rates could not be determined. Mr. Morgan refers to his growth rate as "conservative".

I believe that the more appropriate approach would be to use PPL Electric's 2007 projection of distribution Rent from Electric Property which is based on known contracts and rates. Although the increase between 2006 and 2007 is not as large as that proposed by Mr. Morgan, it is PPL Electric's best estimate of these revenues. There is no basis for the conclusion that PPL Electric will experience an increase in Rent from Electric Property from 2006 to 2007 equivalent to the increase that was experienced from 2005 to 2006. As shown on Schedule 2 of Exhibit JRS 5, the level of Rent from Electric Property varies from year-to-year. In fact, the change in Rent from Electric Property from 2004 to 2005 was negative 3.92%, and the average annual compound growth rate in distribution Rent from Electric Property was only 1.9 percent from 2004 through 2006. PPL Electric's budget for 2007 which projects an increase of 0.72% from 2006 Rent from Electric Property, adjusted to eliminate non-recurring revenue, is consistent with its recent experience.

IV. Employee Expenses

Q. Mr. Morgan recommends decreasing the Company's claim for employee expenses by $500,000 for two reasons. First, he states that PPL Electric did not adequately justify $300,000 of additional employee expenses. In addition, he concluded that PPL Electric overstated its 2007 relocation costs because these relocation costs were associated with the hiring of a new senior executive officer and general manager, which he concludes is not a recurring event. Do you agree with Mr. Morgan's proposed adjustment?

A. No. I do not agree with Mr. Morgan's recommendation. First, it should be noted that PPL Electric's 2007 employee expense claim of $1,206,000 is $349,000 lower than its 2006 actual employee expenses. In fact, the 2007 employee expense budget is significantly lower than the past 3-year average annual employee expenses of $1.5 million. Schedule 3 of Exhibit JRS 5 provides a summary of actual employee expenses incurred between 2004 and 2006. On this basis, it is clear that PPL Electric's future test year claim for employee expenses is conservative and reasonable.

Nevertheless, we recognize that the categorization of employee expenses provided in the response to Question OTS-RE-129-D of Interrogatories of the Office of Trial Staff, Set XIII, dated April 26, 2007, requires some further explanation. Schedule 4 of Exhibit JRS 5 sets forth a simplified breakdown of employee expenses—relocation expenses and all other employee expenses. First, I want to point out that the response to Question OTS-RE-129-D incorrectly reported 2006 relocation expenses of $100,000 instead of $365,290. This error was identified during the development of rebuttal testimony. PPL Electric traditionally budgets $300,000 for employee relocations. Actual relocation expenses are dependent on hiring needs and movement throughout the organization. For the period 2004 through 2006, PPL Electric incurred average annual relocation expenses of $249,000, as shown on Schedule 3 of Exhibit JRS 5. It is also important to note that relocation expenses have increased in each of the last 3 years. As of June 2007, PPL Electric has incurred $280,000 in relocation expenses and

expects to overrun its 2007 relocation expense budget. Based on this information, I believe that the $300,000 for relocation expenses included in PPL Electric's budget is reasonable and should be approved.

The 2007 budget for the all other employee expenses is lower than the 2006 actual and is also lower than the 3-year average of $1.3 million for all other employee expenses. Based on all of the information provided, I believe that the adjustment proposed by Mr. Morgan should be rejected.

V. Telephone and Leased Wires

Q. Mr. Morgan recommends decreasing the Company's telephone and leased wires claim by $400,000. Mr. Morgan bases his recommendation on the response to the Question OTS-RE-129-D of Interrogatories of the Office of Trial Staff, Set XIII, dated April 26, 2007, in which PPL Electric states that the $400,000 increase represented the cost of "additional telephone lines to cover call overflow due to the proposed distribution rate filing". Do you agree with Mr. Morgan's proposed adjustment?

A. No, I do not agree with Mr. Morgan's recommendation. Before specifically commenting on Mr. Morgan's recommendation, I would like to more fully explain the nature of the $400,000 expense claim. The increase represents call handling through a third-party call center during peak times from mid-March through late November in anticipation of customer questions about PPL Electric's distribution rate case. The claim is not just for the rental of additional telephone lines to cover call overflow. Because these expenses are directly

tied to PPL Electric's distribution rate filing, they should be added to PPL Electric's rate case expenses and recovered over a 3-year period. Accordingly, PPL Electric's rate case expenses will be increased by $400,000 and annualized over a 3-year period as shown on Schedule D-6 of Exhibit Future 1-Revised and $400,000 will be removed from Operation and Maintenance Expenses on Schedule D-2a of Exhibit Future 1-Revised.

VI. Materials and Supplies

Q. Mr. Morgan recommends decreasing the Company's materials and supplies claim by $800,000. Mr. Morgan believes that $800,000 of the claim is non-recurring in nature stating that "the budgets for 2008 and 2009 reveal a budget level more in line with the 2006 expense". Do you agree with Mr. Morgan's proposed adjustment?

A. No, I do not agree with Mr. Morgan's recommendation. The response to Question 12 of Interrogatories of the Office of Consumer Advocate, Set I, dated April 25, 2007 (Schedule 5 of Exhibit JRS 5), sets forth the budget for materials and supplies associated with the proactive replacement of equipment prior to its failure which increases from $5,129,000 in 2007, to $5,411,000 in 2008 and to $5,842,000 in 2009. This trend of increased spending emphasizes the need to proactively replace equipment prior to its failure as distribution infrastructure ages. This increased spending is incorporated into PPL Electric's total budget for materials and supplies, which is expected to increase from $6,714,000 in 2007 to $6,943,000 in 2009. As can be seen in the response to Question 12

of Interrogatories of the Office of Consumer Advocate, Set I, dated April 25, 2007, this is significantly higher than actual materials and supplies expense incurred by PPL Electric from 2004 through 2006. In fact, the compound annual growth rate of all materials and supplies expense for the period 2006 through 2009 is expected to be about 8.8%. The primary driver of this increase is the proactive replacement of equipment. Based on this information, I believe that Mr. Morgan's proposed adjustment should be rejected.

VII. Pension Expense

Q. Mr. Morgan recommends a decrease of $1,392,000 to PPL Electric's pension expense claim. This adjustment reflects PPL Corporation's final 2007 actuarial report and a $4.0 million reduction in PPL Corporation's pension cost related to the Black Lung Trust Fund of Pennsylvania Mines Corporation ("PMC"). Do you agree with Mr. Morgan's proposed adjustment?

A. No. However, I do agree with Mr. Morgan's recommendation that an adjustment to pension expense is required to reflect the pension cost in PPL Corporation's final 2007 actuarial report. That adjustment would decrease PPL Electric's pension expense claim by $470,000. However, I do not agree with Mr. Morgan's $4.0 million adjustment to PPL Corporation's pension cost relating to PMC's Black Lung Trust. Mr. Morgan bases this adjustment on his erroneous belief that PMC's retired employees are participants in PPL Corporation's pension plan. This is not the case. PMC's retired union employees are participants in the United Mine Workers of America's pension

plans and its retired non-union employees are participants in the PMC Retirement Plan. PMC established the Black Lung Trust Fund in the 1980's to pay approved black lung benefits, medical claims and associated costs for its miners and their spouses and dependents. Federal legislation enacted in 2006 allows funds in the Black Lung Trust to be used to pay for the other health benefits of the retired coal miners of PMC. The $4.0 million that Mr. Morgan references in his testimony is an estimate of annual funds that may be taken from PMC's Black Lung Trust to pay other health care costs of retired PMC miners. These funds cannot be transferred to PPL Corporation's pension plan. In fact, these funds can only be used for the medical costs of retired coal miners. Schedule 6 of Exhibit JRS 5 includes all of PPL Electric's interrogatory responses related to the PMC Black Lung Trust. Based on this information, Mr. Morgan's $4.0 million adjustment is inappropriate. PPL Electric does recommend a reduction to its pension expense of $470,000 based on the final 2007 actuarial report. Schedule 7 of Exhibit JRS 5 provides the detailed calculation of the Company's proposed adjustment, which is included in Schedule D-2a of Exhibit Future 1-Revised.

Q. Mr. Morgan also recommends an increase in the Company's pension expense claim of $25,000 for the Company's 2007 Supplemental Executive Retirement Plan (SERP) expense using the actuarial study for the 2006 fiscal year. Do you agree with Mr. Morgan's proposed adjustment?

A. Yes. I agree with Mr. Morgan that the Company's SERP claim should be adjusted to more accurately reflect PPL Electric's 2007 SERP expense. Mr. Morgan used PPL Corporation's 2006 actuarial cost to develop his adjustment for SERP. PPL Corporation received an updated estimate of its 2007 SERP costs as of July 5, 2007. This information was included in the supplemental response to Question OTS-RE-69-D of Interrogatories of the Office of Trial Staff, Set X, dated April 23, 2007, provided on July 17, 2007. Based on this information, PPL Electric recommends a $15,000 reduction in its SERP expense claim. Schedule 7 of Exhibit JRS 5 provides the detailed calculation of this adjustment, which is included in Schedule D-2a of Exhibit Future 1-Revised.

VIII. Post Retirement Benefits Other than Pensions (SFAS No. 106)

Q. Mr. Morgan recommends a decrease of $405,000 to the Company's postretirement benefits other than pension expense claim. This adjustment is based on the information provided in PPL Corporation's December 2006 actuarial valuation report for the plan year ended December 31, 2006. Do you agree with Mr. Morgan's proposed adjustment?

A. No. However, I do agree with Mr. Morgan's recommendation that an adjustment to the Company's postretirement benefits other than pension expense claim is needed to reflect PPL Corporation's 2007 costs. During the review of Mr. Morgan's testimony, PPL Electric discovered that it did not provide PPL Corporation's March 2007 Actuarial Valuation Report for the plan

year ending December 31, 2007 in its response to Question OTS-RE-69-D of Interrogatories of the Office of Trial Staff, Set X, dated April 23, 2007. This information was included in the supplemental response to Question OTS-RE-69-D of Interrogatories of the Office of Trial Staff, Set X, dated April 23, 2007, provided on July 17, 2007. Based on information in this report, PPL Electric recommends an increase of $845,000 in its postretirement benefits other than pension expense claim. Schedule 8 of Exhibit JRS 5 provides a detailed calculation of this adjustment, which is included in Schedule D-2a of Exhibit Future 1-Revised.

IX. Property Insurance

Q. Mr. Morgan recommends a reduction to the Company's claim for property insurance expense of $413,000 as a result of an incorrect allocation of PPL Electric's O&M budget to Account 924. Do you agree with Mr. Morgan's proposed adjustment?

A. No, I do not agree with Mr. Morgan's proposed recommendation. As explained in my direct testimony, Statement No. 2, pages 9 through 14, PPL Corporation ("PPL") budgets and monitors expenditures by categories (e.g., payroll, employee expenses, materials and supplies) rather than by FERC account. There are several reasons why PPL has chosen to budget by category. PPL Electric's business line employees are not accountants and cannot reasonably be expected to budget their activities by technical FERC account. Instead, PPL wants the budgeting and monitoring of expenditures to be transparent and

user-friendly. As a result, PPL strongly believes that budgeting by category of work is more reliable and accurate than budgeting by FERC account. For these reasons, PPL Electric's 2007 budget was prepared by category of expense. I am confident that PPL Electric's budget by category is an accurate and reasonable estimate of 2007 expenses. As explained in my direct testimony on page 14, lines 4 though 17, PPL Electric allocated expenditures into FERC accounts, based on the historic test year ended December 31, 2006, to satisfy the Commission's filing requirements at 52 Pa. Code § 53.53.

While this allocation process is reasonably accurate, anomalies can occur. We attempted to identify and remove any such anomalies from the historic test year results. However, this process was not perfect, and as a result, we may have allocated too much to one FERC account with a corresponding under-allocation to another FERC account. This is the reason an additional $413,000 was included in Account 924, Property Insurance. The important point here is that any anomaly is the result of allocating total expenses by category to particular FERC accounts. It does not mean that the overall budget is incorrect, or that any adjustment should be made. Finally, and to further address this issue, in its response to Question OTS-RE-196-D of Interrogatories of the Office of Trial Staff, Set XXXII, dated June 15, 2007 (Schedule 9 of Exhibit JRS 5), the Company stated it would correct the assignment of the budget to FERC accounts in its rebuttal testimony. Schedule 10 of Exhibit JRS 5 sets forth a revised allocation of the budget to FERC accounts, which is shown on Schedule B-4 of Exhibit Future 1-Revised.

Accordingly, I believe that Mr. Morgan's proposed recommendation should be rejected.

X. Amortization of Negative Net Salvage

Q. Mr. Morgan recommends a reduction of $592,000 to the Company's net negative salvage. Mr. Morgan bases this claim on his counsel's advice that the Commission has an established precedent of allowing the net salvage based on five years of historical data rather than including projected data for the future test year. Mr. Morgan's adjustment is based on five years of historical data. Do you agree with Mr. Morgan's proposed adjustment?

A. No, I do not agree with Mr. Morgan's proposed recommendation. PPL Electric's counsel has advised me that the Commission has allowed the amortization of net negative salvage to be based on four years of historical data and one year of projected data. As such, PPL Electric believes that its calculation of negative net salvage of $9,504,000 included in the response to Question II-D-13, of Exhibit Regs., §53.53, Part II-Primary Statements of Rate Base and Operating Income, is correct. However, during the development of rebuttal testimony on this issue, PPL Electric identified an error in its initial filing. Specifically, PPL Electric inadvertently included $12,005,000 of negative net salvage in calculating its future test year depreciation expense rather than the $9,504,000 shown in response to Question II-D-13. As a result, PPL Electric recommends a decrease of $2,501, 000 in its claim for negative net

salvage included in depreciation expense. Schedule 11 of Exhibit JRS 5 sets forth the calculation of this proposed adjustment.

XI. Gain on the Sale of Property

Q. Mr. Kubas recommends that an $820,000 gain, associated with the sale of property, be included in the future test year results as a reduction to the Company's revenue requirements. Mr. Kubas' recommended adjustment is related to a transaction that occurred during the first quarter of 2007 in which PPL Electric recognized a $2, 460,000 gain on the sale of property. Mr. Kubas bases his recommendation on the provisions of 18 C.F.R. Pt. 101,25, Electric Plant Instructions 7.E. Because Mr. Kubas believes that this transaction is a non-recurring event, Mr. Kubas recommends this gain be amortized over three years. Do you agree with Mr. Kubas's proposed adjustment?

A. No, I do not agree with Mr. Kubas's proposed adjustment. Mr. Kubas bases his proposed adjustment on the erroneous belief that the property sold was either Utility Plant (FERC Account 101) or Electric Plant Held for Future Use (FERC Account 105). As explained in the response to Question 3 of Interrogatories of the Office of Consumer Advocate, Set VI, dated May 24, 2007, provided as Schedule 12 of Exhibit JRS 5, the property sold was Non-utility plant (FERC Account 121). As such, this property is not covered under the Code of Federal Regulations that Mr. Kubas cites in his testimony. Furthermore, this property was never included in the Company's rate base. Therefore, reducing the

Company's revenue requirements in this proceeding is clearly inappropriate. Therefore, Mr. Kubas' proposed adjustment should be rejected.

Q. Mr. Schadt, are there any documents that summarize PPL Electric's witnesses' *proposed adjustments and the impact to PPL Electric's rate request*?

A. Yes. PPL Electric is filing Exhibit Future 1-Revised to reflect the changes described in this testimony and the testimonies of Messrs. Dahl, Kasper, Kleha, Krall, and Woodruff. Schedule 13 of Exhibit JRS 5 provides a summary of the Company's proposed adjustments.

Q. Does that conclude your rebuttal testimony?

A. Yes.

PPL Electric Utilities Corporation

Exhibit JRS 5

Docket No. R-00072155

Operating Revenues and O&M Expenses

Schedule 1
Document 1

PPL Electric Utilities Corporation
Late Payment Revenues
For the Year ending December 31, 2007
(Thousands of Dollars)

		Total Sale of Electricity Revenue Net of Provision for Rate *Refund*		Forefeited *Discounts*	Three-year weighted *average*
12 months ended					
	12/31/2006	$ 3,226,067	(1)	$ 10,107	
	12/31/2005	3,100,200	(2)	8,784	
	12/31/2004	2,795,962	(2)	8,165	
		$ 9,122,229		$ 27,056	0.2966%

Total Sale of Electricity Revenues (excluding Provision for Rate Refund)	3,125,767	(3)
Less: Sales to PPL Generation	3,079	
	3,122,688	
Three-year weighted average	0.2966%	
Revised Forfeited Discounts	$ 9,262	
Forfeited Discounts included in the filing	8,923	
Proposed Adjustment--Increase	$ 339	

(1) Per Page 300, Lines 14 and 16 of PPL Electric Utilities Corporation's FERC Form 1 for the year ended December 31, 2006.

(2) Per the response to Question 3 of Interrogatories of the Office of Consumer Advocate, Set VII, dated June 1, 2007.

(3) Total Sales of Electricity Revenue including the intangible transition charge.

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Consumer Advocate, Set VII,
Dated June 1, 2007
Docket No. R-00072155

Q.3. With reference to the response to OTS-RE-33-D, please provide documentation showing the derivation of the $8,923,000 late payment revenues.

A.3.

(Thousands of Dollars)			
12 months ended	Total Revenue Net of Provision For Refund	Late Payment Revenue	Three-year weighted average
12/31/05	$ 3,100,200	$ 8,784	
12/31/04	2,795,962	8,165	
12/31/03	2,739,050	7,726	
	$ 8,635,212	$ 24,674	0.2857%
2007 Projection for Late Payment Revenue			
Projected Sales Revenue	$ 3,125,767		
Less: Sales to PPL Generation	3,079		
Adjusted Revenue Projection	$ 3,122,668	$ 8,923	0.2857%

Schedule 2
Document 1

PPL Electric Utilties Corporation
Rent from Electric Property-Distribution
For the Year ending December 31, 2007
(Thousands of Dollars)

	PUC Jurisdictional Revenues							
	Actual 2004		Actual 2005		Actual 2006		Projected 2007	
Rent from Pole Attachments	$ 19,957	(1)	$ 18,962	(1)	$ 21,458	(3)	$ 21,702	
Rent from Electric Property	825	(1)	732	(1)	181	(4)	225	
Facilities Rent-Distributed	7,593	(2)	7,568	(1)	7,842	(1)	7,766	
	$ 28,375		$ 27,262		$ 29,481		$ 29,693	
% Change from Previous Year			-3.92%		8.14%		0.72%	
Compound Annual Growth Rate 2004 -2006	1.93%							

(1) Per the response to Question OTS-RE-46-D of Interrogatories of the Office of Trial Staff, Set VI, dated April 19, 2007.
(2) Estimated facilities rent that was credited against expense in 2004 using information provided in the response to Question OTS-RE-185-D of Interrogatories of the Office of Trial Staff, Set XXVIII, dated June 11, 2007.
(3) Excludes $650,000 of non-recurring revenue. See the response to Question 9 of Interrogatories of the Office of Consumer Advocate, Set VI, dated May 24, 2007.
(4) Excludes $600,000 of non-recurring revenue. See the response to Question 9 of Interrogatories of the Office of Consumer Advocate, Set VI, dated May 24, 2007.

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Trial Staff, Set VI,
Dated April 19, 2007
Docket No. R-00072155

Q.OTS-RE-46-D. Reference the $30,731,000 of rent – electric property revenue for 2006 shown on PPL Exhibit JMK-1, page 26, line 12:

A. Provide a breakdown showing the different types of revenue included in the $30,731,000.

B. Provide a schedule that shows the amount of rent – electric property revenue received in 2004 and 2005.

C. The Company received $18,774,000 in rent – electric property revenue in the last base rate case. Comparing the actual 2006 amount with the projected 2007 amount, explain why the Company believes the amount in 2007 will decrease to $29,693,000 as shown on PPL Exhibit JMK-2, page 26, line 11, when the amount of rent-electric property revenue has increased approximately 63% since 2003.

A.OTS-RE-46-D. A.

	Thousands of Dollars
	2006
Rent from Pole Attachments	$22,108
Rent from Electric Property	781
Facilities Rent – Distributed	7,842
Total	$30,731

B.

	Thousands of Dollars	
	2004	**2005**
Rent from Pole Attachments	$19,957	$18,962
Rent from Electric Property	825	732
Facilities Rent – Distributed	0	7,568
Total	$20,782	$27,262

C. Actual revenue in 2006 includes several non-recurring items, such as past charges for unauthorized attachments to PPL Electric's poles and a settlement related to rent of PPL Electric's fiber-optic system.

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Trial Staff, Set XXVIII,
Dated June 11, 2007
Docket No. R-00072155

Q.OTS-RE-185-D. *Reference the Company's response to OCA Set I – 36 – 2.*

A. Identify the charges to other affiliates PPL Electric plans in the test year 2007.

B. Provide a breakdown of PPL Electric charges to other affiliates of PPL Corporation in 2003, 2004 and 2005.

A.OTS-RE-185-D. A.

Engineering and Design Support	$2,029,000
Building rental fees	$8,670,000

B. See Attachment 1.

PPL Electric Utilities Corporation
Charges to Other PPL Corporation Affiliates
(Thousands of Dollars)

	2003	2004	2005
Field Services Physical Labor Support (A)	$ 42,307	$ 40,924	$ -
Engineering and Design Support	$ 1,942	$ 2,699	$ 3,091
Building rental fees	$ 13,034	$ 8,608	$ 8,580

(A) At the end of 2004, Field Services personnel supporting generation transferred from PPL Electric to other affiliates of PPL Corporation

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Consumer Advocate, Set VI,
Dated May 24, 2007
Docket No. R-00072155

Q.9. With reference to the response to OTS-RE-46-D, please provide the amounts associated with past charges for unauthorized attachments and the settlement amount related to the rental of PPL Electric fiber-optic system, as indicated in the response.

A.9. In 2006 non-recurring rent revenue from past charges for unauthorized attachments to PPL Electric's poles was $650,000, and the settlement for the PPL Electric fiber-optic system rent was $600,000.

Schedule 3
Document 1

PPL Electric Utilities Corporation
Employee Expenses to O&M
2002-2006
(Thousands of Dollars)

Year	Actual		Relocation Expenses	All Other
2004	1,222	(1)	180	1,042
2005	1,768	(1)	201	1,567
2006	1,555	(2)	365	1,190
	$ 4,545		$ 746	$ 3,799
3-year average	$ 1,515		$ 249	$ 1,266

(1) Per the response to Question OTS-RE-129-D of Interrogatories of the Office of Trial Staff, Set XIII, dated April 26, 2007.
(2) Per Attachment II-D-1b of the response to Question II-D-1, of Exhibit Regs., §53.53, Part II- Primary Statements of Rate Base and Operating Income.

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Trial Staff, Set XIII,
Dated April 26, 2007
Docket No. R-00072155

Q.OTS-RE-129-D. Reference the Company's Attachment II-D-1b, page 2 concerning operating and maintenance expenses – other operating costs.

A. Provide a schedule of the other operating costs listed on page 2 for the twelve months ended 12/31/2002, 2003, 2004 and 2005.

B. Provide an explanation and breakdown by the amount for major items included in the employee expenses category amount of $1,555,000 in the twelve months ended 2006 and in the projected amount of $1,206,000 for the twelve months ended 2007. Include all supporting calculations for the projected amount.

C. Provide an explanation and detailed breakdown by the amount for major items included in the materials and supply category amount of $5,390,000 in the twelve months ended 2006 and in the projected amount of $6, 714,000 for the twelve months ended 2007. Include all supporting calculations for the projected amount.

D. Provide an explanation and detailed breakdown by the amount for major items included in the tree trimming category amount of $25,570,000 in the twelve months ended 2006 and in the projected amount of $28,064,000 for the twelve months ended 2007. Include all supporting calculations for the projected amount.

E. Provide an explanation and detailed breakdown by the amount for major items included in the Services category amount of $4,513,000 in the twelve months ended 2006 and in the projected amount of $4,545,000 for the twelve months ended 2007. Include all supporting calculations for the projected amount.

F. Provide an explanation and detailed breakdown by the amount for major items included in the Services category amount of $4,513,000 in the twelve months ended 2006 and in the projected amount of $4,545,000 for the twelve months ended 2007. Include all supporting calculations for the projected amount.

G. Provide an explanation and detailed breakdown by the amount

for major items included in the postage category amount of $5,472,000 in the twelve months ended 2006 and in the projected amount of $5,493,000 for the twelve months ended 2007. Include all supporting calculations for the projected amount.

H. Provide an explanation and detailed breakdown by the amount for major items included in the telephone and leased wires category amount of $3,601,000 in the twelve months ended 2006 and in the projected amount of $4,004,000 for the twelve months ended 2007. Include all supporting calculations for the projected amount.

I. Provide an explanation and detailed breakdown by the amount for major locations and types of locations included in the rent category amount of $9,515,000 in the twelve months ended 2006 and in the projected amount of $8,477,000 for the twelve months ended 2007. Include all supporting calculations for the projected amount. Include the address of major locations and identify the ownership.

A.OTS-RE-129-D. A. See Attachment 1.

B. Expenditures for 2006 of $1.5 million are broken into the following categories:

- $500,000 is for employee expenses associated with overtime and training, such as: mileage, parking fees, meals and any miscellaneous out-of-pocket expenses paid for by the employee
- $100,000 is associated with employee relocation costs
- $950,000 is for employee meals, mileage and lodging associated with overtime related to PUC reportable storm activity throughout the year.

Projected expenses for 2007 are based on historical spending, excluding any unusual amounts related to PUC reportable storm activity. Projections are based on the following categories:

- $600,000 is related to employee expenses as described above
- $300,000 is projected for employee relocations for any new employees and employees transferring within the Company's service territory due to new work assignments.
- $300,000 is projected for item, e.g., offsite seminars/conferences, which include air fare, car rentals, lodging and registration fees.

C. For 2006, the major categories for materials and supplies were:

- $1,198,000 for repairs and replacement of substation equipment, e.g., interrupters, contact rods, fuses, bushings, gaskets, and cable,
- $1,201,000 for repairs and replacement of equipment to restore power to customers, e.g., fuses, cutouts, arrestors, and cable,
- $1,073,000 for repairs or replacement of overhead line and underground cable equipment, e.g., fuses, cutouts, arrestors, insulators, controls, and cable,
- $886,000 for equipment required to connect, change or remove a customer's service, e.g., fuses, cables, and splices,
- $678,000 for replacement of street/area lights, e.g., bulbs, ballasts and cable, and
- the remainder is for other miscellaneous work.

For the twelve months ended 2007, the projected amounts by major categories for materials and supplies are:

- $1,927,000 for repairs and replacement of substation equipment
- $858,000 for repairs and replacement of equipment to restore power to customers,
- $1,697,000 for repairs or replacement of overhead line and underground cable equipment,
- $882,000 for equipment required to connect, change or remove a customer's service,
- $647,000 for replacement of street/area lights, and
- the remainder is for other miscellaneous work.

D. For 2006, the major categories for tree trimming were:

- $23,421,000 for tree trimming and removals, and
- $2,149,000 for herbicide applications.

For 2007, the major categories for tree trimming are:

- $26,830,000 for tree trimming and removals, and
- $1,234,000 for herbicide applications.

E. For 2006, the major categories for services are:

- $2.4 million of costs associated with various collection services and vendor support for the Customer Service System (CSS)
- $0.7 million of costs for supplier coordinator services

program done by affiliate company
- $0.4 million for various survey services
- $1.0 million vendor support services associated with training issues both job-related training and soft-skill type training.

The projected amount for 2007 is based on the above expenditures. An additional amount of $30,000 is an increase expected for additional training.

F. See the response to Item E.

G. For 2006, the major categories for postage are:

- $4.9 million spent on postage paid for the mailing of regular monthly bills, which include both manual and summary bills
- $0.5 million for postage paid on all miscellaneous letters and correspondence.

The projected amount for 2007 is based on the above expenditures.

H. For 2006, the major categories for telephone and leased wires are

- $1.0 million for communication lines associated with distribution and transmission system operations.
- $1.0 million in communication lines associated with Customer Contact and Customer Call Centers, as well as Voice Recording system
- $1.5 million in communication lines designated for the Automated Meter Reading system.

The projected amount for 2007 includes the above amounts, plus an increase of $0.4 million for additional telephone lines to cover call overflow due to the proposed distribution rate filing.

I. For 2006, rents paid were not for locations, but for items such as:

- $7.8 million associated with rentals related to joint use agreements.
- $0.4 million for miscellaneous rental agreements for rights-of-way, railroad license fees, and state agency license agreements.
- $0.4 million for rental of test equipment used for the testing of special equipment
- $0.9 million for miscellaneous rental of equipment used at job sites

The projected amount for 2007 includes all of the above costs, except the joint use agreements. Amount projected for 2007 are based on information prior to annual true-up factor on the number of agreements, which occurs with annual billings in June or July.

Schedule 3
Document 3
OTS -RE-129-D
Attachment 1

PPL Electric Utilities Corporation
Other Operating Costs
(Thousands of Dollars)

	2002	2003	2004	2005
Employee Expenses	$ 1,381	$ 1,817	$ 1,222	$ 1,768
Vehicles & Equipment Use	10,261	12,969	10,522	12,398
Materials & Supplies	4,516	6,098	5,096	4,461
Printing & Office Supplies	685	793	740	507
Tree Trimming	14,342	17,333	17,436	20,191
Work by Outsiders	31,661	48,759	45,225	57,650
Services	1,829	6,000	3,195	3,010
Postage	4,804	5,076	5,235	4,906
Telephone & Leased Wires	1,686	2,401	2,909	3,450
Rents	6,840	7,277	9,766	8,649
Advertising	291	2,499	2,176	264
Uncollectible Accounts	23,539	23,183	22,193	22,781
Miscellaneous	31,431	(2,520)	27,547	(2,443)
PPL Electric Other Operating Costs	$ 133,266	$ 131,685	$ 153,262	$ 137,592

Schedule 4
Document 1

PPL Electric Utilities Corporation
Employee Expenses
2006 Actual vs. 2007 Budget
(Thousands of Dollars)

	Actual 2006	Budget 2007	Change
Relocation expenses	$ 365	$ 300	$ (65)
All Other	1,190	906	(284)
	$ 1,555	$ 1,206	$ (349)

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Consumer Advocate, Set I,
Dated April 25, 2007
Docket No. R-00072155

Q.12. With reference to the materials and supplies costs budgeted in 2007 for the repair of non-capital requirement,

a. Please provide the amount of the 2007 increase related to the repairs of non-capital equipment and identify the repairs to be made during 2007.

b. If the Company believes the 2007 repairs related to the increase in materials costs is an ongoing activity, please provide documentation to support the claim of the ongoing nature of these activities and the budget amount for 2007, 2008 and 2009.

c. Please provide actual material sand supplies expense for 2004, 2005 and 2006.

A.12. a. See the response to Question OTS-RE-129-D, Item D, of Interrogatories of the Office of Trial Staff, Set XIII, dated April 26. 2007.

b. PPL Electric takes a proactive role to replace equipment prior to failures that could result in customer outages, because, historically, the Company saw increasing trends in distribution overhead/underground transformers and secondary failures. The budget for materials and supplies in 2007, 2008 and 2009 are $5,129,000, $5,411,000, and $5,842,000, respectively.

c.

	Thousands of Dollars
2004	$5,096
2005	$4,461
2006	$5,390

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Consumer Advocate, Set I,
Dated April 25, 2007
Docket No. R-00072155

Q.17. With regard to the ability to use funds from the Black Lung Trust assets to offset future benefit payments for retired miners medical costs,

a. Please explain what the Black Lung Trust is and the value of the trust. Include an explanation of who established the trust.

b. Please explain how it is possible for PPL to use funds from the trust to offset its future costs, and what are the conditions that enables PPL to access those funds.

c. How often can PPL access funds from the Black Lung Trust?

d. Does the 2007 budget reflect any funds advanced from the Black Lung Trust? If yes, what is the amount and how is it included in the budget? If not, explain why not.

A.17. a. The Black Lung Benefits Revenue Act of 1977 recognized a liability on the part of coal mine construction and transportation employers, as well as coal mine operators to pay benefits for their employees who work in and around coal mines and are exposed to coal dust. That law permitted employers were eligible to establish a trust to fund the payment of black lung benefits to satisfy their liability. Pennsylvania Mines Corporation (PMC), a subsidiary of the former Pennsylvania Power & Light Company ("PP&L"), created the Black Lung Trust Fund in the 1980s to pay black lung benefit and medical claims and the associated costs for its retired coal miners, their spouses and dependents. The total value of assets in the Black Lung Trust is approximately $55 million, offset by approximately $12 million of Black Lung obligations.

b. On August 17, 2006, President Bush Signed H.R. 4, the Pension Protection Act of 2006. A provision in the Pension Protection Act of 2006 eliminates the aggregate limit under Section 501(c)(21) of the Internal Revenue Code on the amount of excess black lung benefit trust assets that may be used to pay accident and health benefits or premiums for insurance exclusively covering such benefits (including administrative and other incidental expenses relating to such benefits) for retired coal miners and their spouses and dependents. The provision is effective for taxable years beginning after December 31, 2006. The elimination of this aggregate limit frees up certain excess funds from PMC's Black Lung Trust to pay for the health benefits of retired coal miners of PMC. The excess funds are legally restricted to this purpose only.

c. There are no restrictions on the timing of access to funds, as long as excess funds are available pursuant to the requirements of IRC Section 501(c)(21) and are used only for the payment of medical cost for retired miners, as defined in Item b.

d. PPL Electric records all retired miners health care and black lung activity in generation - related accounts. As such, they have been excluded from all prior transmission and distribution rate filings of the Company, were excluded from this filing.

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Consumer Advocate, Set VI,
Dated May 24, 2007
Docket No. R-00072155

Q.19. With regard to the response to OCA I-17, the response indicates that the Black Lung Trust has a total asset value of $55 million.

A. Is the $55 million the value after the $36 million was used in 2006? If not, is the value of the trust $19 million after deducting the $36 million, with $7 million as the current value of excess funds.

B. Is it correct that all amounts above the $12 million Black Lung obligation may be used as described in Item (b) of the Company's response? If not, please explain what can and cannot be used.

C. Specifically, what was the $36 million used for?

D. If the amount of the excess asset value of the Black Lung Trust Asset that is available for use to offset future benefit payments of retired miners is determined by a different method than assumed above (item [a]), please fully explain how it is determined and the current excess asset amount available.

A.19. A. The value of the securities in the Black Lung Trust is $55 million, prior to any adjustments or excess asset calculations. Excess assets represent the difference between those assets and 110% of the $11 million of actuarial obligations for Black Lung, or $12 million. Thus, the net assets available for retired miners health benefits is approximately $43 million, of which $36 million was used to reduce the UMWA Retired Miners Health Care liability.

B. Yes.

C. The Company recorded a $36 million reduction in its recorded liability for retired miners' health care and will use the cash from the Black Lung Trust to pay health care costs of retired miners.

D. See the responses to Items A and B.

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Consumer Advocate, Set VI,
Dated May 24, 2007
Docket No. R-00072155

Q.20. Please explain the Company's current plan for any excess Black Lung Trust assets. Indicate the amount the Company plans to use during 2007, 2008 and beyond.

A.20. The Company will use excess Black Lung assets at a rate of approximately $4 million per year to pay retired miners health care costs.

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Consumer Advocate, Set VI,
Dated May 24, 2007
Docket No. R-00072155

Q.21. According to the response to OCA I-17(d), the records of retired miners' healthcare and Black Lung activity is considered generation-related. Please explain why the assets from the Black Lung Trust were reflected in the transmission and distribution company operating costs.

A.21. As indicated in the response to Question 17 of Interrogatories of the Office of Consumer Advocate, Set I, dated April 25, 2007, all retired miners' health care and black lung activity is recorded in generation-related accounts. As such, this activity is not reflected in PPL Electric's T&D operating expenses.

Schedule 7
Document 1

PPL Electric Utilities Corporation
Revised Pension Expense
For the Year ending December 31, 2007
(Thousands of Dollars)

	PPL Retirement Plan		PPL SERP		Total
Total Plan- Pension Cost	$ 25,966	(1)	$ 7,187	(2)	$ 33,153
PPL Electric Pension Cost					
Allocatiion of 35.75% based on the actuarial allocation of total obligations.(3)	9,283				9,283
Allocation of 7.59% based on employees *and retirees covered under the plan.*(3)			545		545
PPL Electric Net Pension Expense					
Approximately 64.5% of cost is charged to O&M based on the payroll distribution (3)	5,987		352		6,339
Expense per filing (3)	6,457		367		6,824
Proposed Adjustment--(Decrease)	$ (470)		$ (15)		$ (485)

(1) Per the response to Question OTS-RE-69-D of Interrogatories of the Office of Trial Staff, Set X, dated April 23, 2007.

(2) Per the Supplemental Response to Question OTS-RE-69-D of Interrogatories of the Office of Trial Staff, Set X, dated April 23, 2007, sent July 17, 2007.

(3) Per the response to Question 38 of Interrogatories of the Office of Consumer Advocate, Set I, dated April 25, 2007.

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Consumer Advocate, Set I,
Dated April 25, 2007
Docket No. R-00072155

Q.38. With reference to pension expense included in the future test year cost of service,

a. Please identify the amount included in O&M expenses and the ratio used to derive the O&M portion of those costs.

b. Please provide the total pension cash contribution (payments) for 2004, 2005, 2006 and projected 2007.

c. Please provide the SFAS 87 pension expense amounts for 2004, 2005, 2006 and projected 2007.

A.38. a. The Company's claimed pension O&M expense of $6,824,000 for the 2007 future test year is based on an allocation of the SFAS 87 amount attributable to PPL Electric's participation in the PPL Retirement Plan and PPL Supplemental Executive Retirement Plan (PPL SERP), calculated as follows:

(Thousands of Dollars)

	PPL Retirement Plan	PPL SERP	Total
Total Plan Pension Expense	$28,000	$7,500	$35,500
PPL Electric Gross Pension Expense			
PPL Electric allocation of 35.75% based on actuarial allocation of total obligations.	$10,010		$10,010
PPL Electric allocation of 7.59% based on employees and retirees covered under the plan.		$570	$570
PPL Electric Net Pension Expense charged to O&M			
Approximately 64.5% of expense charged to O&M based on payroll distribution	$6,457	$367	$6,824

b.

(Thousands of Dollars)

	PPL Retirement Plan	PPL Supplemental Executive Retirement Plan (SERP)
2007	$10,010	$780
2006	11,564	288
2005	5,315	280
2004		273

c.

(Thousands of Dollars)

	PPL Retirement Plan	PPL Supplemental Executive Retirement Plan (SERP)
2007	$10,010	$570
2006	7,430	565
2005	5,033	535
2004	1,377	518

Schedule 8
Document 1

PPL Electric Utilites Corporation
Revised Post Retirement Other than Pension Costs
For the Year ending December 31, 2007
(Thousands of Dollars)

	Amount	
Total Plan- Post Retirement other than Pension Costs	$ 39,505	(1)
PPL Electric Post Retirement other than Pension Costs		
Allocatiion of 37.41% based on the actuarial allocation of the total obligations.(2)	14,779	
PPL Electric Post Retirements other than Pension Costs to Expense		
Approximately 64.5% of cost is charged to O&M based on the payroll distribution (2)	$ 9,532	
Expense per filing (2)	8,687	
Proposed Adjustment--Increase	$ 845	

(1) Per the Supplemental Response to Question OTS-RE-69-D of Interrogatories of the Office of Trial Staff, Set X, dated April 23, 2007, sent July 17, 2007.

(2) Per the response to Question 39 of Interrogatories of the Office of Consumer Advocate, Set I, dated April 25, 2007.

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Consumer Advocate, Set I,
Dated April 25, 2007
Docket No. R-00072155

Q.39. With reference to postretirement benefit expense included in the future test year cost of service,

a. Please identify the amount included in O&M expenses and the ratio used to derive the O&M portion of those costs.

b. Please provide the total postretirement cash benefits contribution (payments) for 2004, 2005, 2006 and projected 2007.

c. Please provide the SFAS 106 postretirement benefits amounts for 2004, 2005, 2006 and projected 2007.

A.39. a. The Company's claimed postretirement O&M expense for future test year of $8,688,000 is based on an allocation of the SFAS 106 amount attributable to PPL Electric's participation in the PPL Postretirement Benefit Plans, calculated as follows:

(Thousands of Dollars)

	Amount
Total Postretirement Benefit Plan Expense	$36,000
PPL Electric Gross Postretirement Expense	
PPL Electric allocation of 37.41% based on actuarial allocation of total obligations.	$13,469
PPL Electric Net Postretirement Expense charged to O&M	
Approximately 64.5% of expense charged to O&M based on payroll distribution	$8,688

b.

(Thousands of Dollars)

	PPL Postretirement Plan
2007	$13,469
2006	12,900
2005	12,573
2004	16,589

c.

(Thousands of Dollars)

	PPL Postretirement Plan
2007	$13,469
2006	12,144
2005	11,062
2004	13,273

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Trial Staff, Set XXXII,
Dated June 15, 2007
Docket No. R-00072155

Q.OTS-RE-196-D. Reference the Company's response to OTS-RE-66-D, part A and Part B, attachment 1 and 2, concerning account 921 office supplies and expenses.

A. Provide a breakdown of the items included in the "other" amount of $875,000 for the historic year 2006.

B. Provide a breakdown of what is included in the "other" amount of $2,419,000 for the future test year of 2007.

C. Provide a justification for the increased expenses.

A.OTS-RE-196-D. A. The $875,000 in Other Miscellaneous charges represents many minor accounting adjustments and system generated accounting entries that appear on the general ledger. See Attachment 1.

B. & C. The 2007 budget amount of $2,419,000 shown for this account primarily is the result of an allocation of the 2007 budget to Account 921. PPL Electric's budget is prepared by budgeting to category of expense, not by FERC account. In general, specific budget dollars were assigned to specific FERC accounts; the remaining dollars were allocated to other FERC expense accounts. See Statement No. 2, the direct testimony of J.R. Schadt, page 14, lines 4 through 17, for an explanation of the allocation of budgeted categories of operation and maintenance expenses to FERC accounts. The $2,419,000 should not have been allocated to Account 921, but instead should have been assigned to other FERC expense accounts. The Company will correct this assignment in its rebuttal testimony.

PPL ELECTRIC UTILITIES CORPORATION

Electric Service
Statement of Operation and Maintenance Expenses
Year Ended December 31, 2007
(Thousands of Dollars)

Acct. No.	Title of Account	Amount
	Power Production Expenses	
	Other Power Supply Expenses	
555	Purchased power	
	Affiliates	$ 1,763,218
	Non-utility generation	145,734
	PJM ancillary services	43,273
	Other	
556	System control and load dispatching	
	PJM ancillary services	-
	Other	-
557	Other expenses	-
	Total Other Power Supply Expenses	1,952,225
	Total Power Production Expenses	1,952,225
	Transmission Expenses	
	Operation	
560	Operation supervision and engineering	1,991
561	Load dispatching	13,091
562	Station expenses	1,038
563	Overhead line expenses	1,520
564	Underground line expenses	2
565	Transmission of electricity by others	141,595
566	Miscellaneous transmission expenses	2,218
567	Rents	365
	Total Transmission Operation Expenses	161,820
	Maintenance	
568	Maintenance supervision and engineering	373
569	Maintenance of structures	776
570	Maintenance of station equipment	4,805
571	Maintenance of overhead lines	10,178
572	Maintenance of underground lines	93
573	Maintenance of miscellaneous transmission plant	457
	Total Transmission Maintenance Expenses	16,682
	Total Transmission Expenses	178,502

PPL ELECTRIC UTILITIES CORPORATION

Electric Service
Statement of Operation and Maintenance Expenses
Year Ended December 31, 2007
(Thousands of Dollars)

Acct. No.	Title of Account	Amount
	Regional Market Expenses	
	Operation	
575.7	Market Facilitation, Monitoring and Compliance Services	$ 4,224
	Total Regional Market Expenses	4,224
	Distribution Expenses	
	Operation	
580	Operation supervision and engineering	15,825
581	Load dispatching	5,005
582	Station expenses	623
583	Overhead line expenses	14,900
584	Underground line expenses	5,423
585	Street lighting and signal system expenses	552
586	Meter expenses	7,771
587	Customer installations expenses	5,043
588	Miscellaneous distribution expenses	4,792
589	Rents	7,889
	Total Distribution Operation Expenses	67,823
	Maintenance	
590	Maintenance supervision and engineering	1,361
591	Maintenance of structures	87
592	Maintenance of station equipment	8,281
593	Maintenance of overhead lines	46,555
594	Maintenance of underground lines	7,732
595	Maintenance of line transformers	2,154
596	Maintenance of street lighting and signal systems	2,581
597	Maintenance of meters	69
598	Maintenance of miscellaneous distribution plant	1,649
	Total Distribution Maintenance Expenses	70,469
	Total Distribution Expenses	138,292
	Customer Accounts Expenses	
	Operation	
901	Supervision	495
902	Meter reading expenses	3,223
903	Customer records and collection expenses	26,385
904	Uncollectible accounts	20,155
905	Miscellaneous customer accounts expenses	830
	Total Customer Accounts Expenses	51,088

PPL ELECTRIC UTILITIES CORPORATION

Electric Service
Statement of Operation and Maintenance Expenses
Year Ended December 31, 2007
(Thousands of Dollars)

Acct. No.	Title of Account		Amount
	Customer Service and Informational Expenses		
	Operation		
908	Customer assistance expenses		
	On-track uncollectible accounts	$	4,500
	Other		8,398
909	Informational and instructional expense		4,400
910	Miscellaneous customer service and informational expenses		223
	Total Customer Service and Informational Expenses		17,521
	Sales Expenses		
	Operation		
911	Supervision		24
912	Demonstrating and selling expenses		1,360
913	Advertising expenses		200
916	Miscellaneous sales expenses		1,520
	Total Sales Expenses		3,104
	Administrative and General Expenses		
	Operation		
920	Administrative and general salaries		5,296
921	Office supplies and expenses		74,146
923	Outside services employed		228
924	Property insurance		7,560
925	Injuries and damages		1,186
926	Employee pensions and benefits		30,791
928	Regulatory commission expenses		4,732
930	Miscellaneous general expenses		576
			124,515
	Maintenance		
935	Maintenance of general plant		14,651
	Total Administrative and General Expenses		139,166
	Total Operation and Maintenance Expenses	$	2,484,122

Schedule 11

PPL ELECTRIC UTILITIES CORPORATION

Proposed Adjustment to Negative Net Salvage
(Thousands of Dollars)

12 Months Ending	Cost of Removal	Gross Salvage	Negative Net Salvage
December 31, 2003	$ 11,860	$ (1,802)	$ 10,058
December 31, 2004	13,097	(1,453)	11,644
December 31, 2005	11,076	(5,906)	5,170
December 31, 2006	13,710	(2,564)	11,146
December 31, 2007	12,435	(2,932)	9,503
Total for 5-year period ending December 31, 2007	$ 62,178	$ (14,657)	$ 47,521

Negative Net Salvage Claim	$ 9,504
Less: Negative Net Salvage included in Scheudle D-11 of Exhibit Future 1	12,005
Proposed adjustment	$ (2,501)

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Consumer Advocate, Set VI,
Dated May 24, 2007
Docket No. R-00072155

Q.3. With regard to the sale of land shown on Attachment 1 to the response to OCA I-1,

A. Please identify the account in which the land was recorded prior to the sale.

B. Please indicate whether this was land on which the Company was allowed to accrue AFUDC.

C. Please identify the amount of the gain on the sale of the land and what amount the Company plans to pass through to ratepayers.

A.3. A. Account 121 - Nonutility Property.

B. AFUDC was not accrued for this property.

C. The gain on the sale of this property was $2,460,058. This gain was recorded in Other Income and (Deductions) and is not included in the Company's cost of service claim.

PPL ELECTRIC UTILITIES CORPORATION
Proposed Adjustments Reflected in Exhibit Future 1-Revised
(Thousands of Dollars)

	Schedule	Total T&D Operations			PUC Jurisdictional		
		Rate Base	Revenue	Operating Expenses	Rate Base	Revenue	Operating Expenses
Proposed Adjustments:							
1. Elimination of Plant held for Future Use	C-3	$ (20,255)			$ (2,002)		
2. Decrease in avg. lag in days between the payment of O&M expenses and receipt of revenue	C-4	(909)			(516)		
3. Increase in revenue annualization	D-3		$ 5,792			$ 1,191	
4. Increase in late payment revenue	D-3		339			336	
5. Increase in miscellaneous revenue	D-3		369			369	
6. Increase in post retirement benefits other than pensions	D-2a			$ 845			$ 845
7. Decrease in pension expense	D-2a			(470)			(470)
8. Decrease in SERP expense	D-2a			(15)			(15)
9. Decrease in telephone & leased Wires	D-2a			(400)			(400)
10. Increase in rate case expense	D-6			133			133
11. Decrease in amortization of negative net salvage	D-11			(2,501)			(2,181)
12. Decrease in PA. capital stock expense	D-12			(900)			(709)
		$ (21,164)	$ 6,500	$ (3,308)	$ (2,518)	$ 1,896	$ (2,797)
Other Changes reflected in Future 1-Revised:							
Revised cost of debt for 2007 debt issuance from 5.70% to 6.40%	B-6						

Schedule 13

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00072155

PPL ELECTRIC UTILITIES CORPORATION

Statement No. 4-R

Rebuttal Testimony of David R. Woodruff

Rebuttal Testimony of David R. Woodruff

Q. Please state your name, title, and business address.

A. David R. Woodruff, Manager–Load Analysis for PPL Electric Utilities Corporation, Two North Ninth Street, Allentown, Pennsylvania, 18101.

Q. Mr. Woodruff, have you submitted testimony previously in this proceeding?

A. Yes, I submitted my direct testimony, Statement 4, on March 29, 2007.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the direct testimony of Mr. Kubas of the Office of Trail Staff, in which he addresses the present rate revenue presented by PPL Electric in the proceeding.

Q. Please summarize your rebuttal testimony.

A. Mr. Kubas specifically made two recommendations related to present rate revenue. First, he proposed that the Company's present rate revenue be increased by $1,186,000 to reflect a corrected annualization adjustment set forth in PPL Electric's response to Question OTS-RE-3-D of Interrogatories of the Office of Trial Staff, Set I, dated April 16, 2006. Second, he proposed to increase the Company's present rate revenue by

an additional $589,800 to reflect his higher estimate of residential customer growth than that forecasted by PPL Electric.

2007 Annualization

Q. Do you agree with Mr. Kubas' recommendation related to the annualization adjustment?

A. Yes. It always has been PPL Electric's intention to correct the 2007 annualization adjustment in its final accounting claim set forth in Exhibit Future 1-Revised. This is the corrected annualization adjustment provided in response to Question OTS-RE-3-D, with one minor revision. PPL Electric recently identified an error in the Rate Schedule BL annualization amount. This correction changes the Distribution annualization for Rate Schedule BL rate by $6,848, and the overall annualization adjustment increases by the same amount. The corrected annualization provided in the attached Exhibit DRW 1-Revised is included in Exhibit Future 1-Revised.

2007 Residential Customer Growth

Q. Do you agree with Mr. Kubas' recommendation related to the growth in the number of residential customers in 2007?

A. No. Mr. Kubas suggests that PPL Electric's forecast of the increase in the number of residential customers for the end of 2007 should be 11,653, which is 1,848 customers higher than the 9,805 projected by the Company.

Q. What is the basis for Mr. Kubas' projection?

A. Mr. Kubas based his projection on a simple two-year average of the change in the number of residential customers in 2005 and 2006.

Q. Is Mr. Kubas' projection reasonable?

A. No. The housing market in PPL Electric's service area experienced a period of tremendous growth during the first half on this decade. This growth has not continued, and in fact, has fallen off significantly. The data used by Mr. Kubas supports this fact. He states that "the company added 11,904 residential customers in 2005 and 11,400 residential customers in 2006," which is a 4% decline. Mr. Kubas later asserts that "the projected number of customers added in 2007 would have been even greater if year 2004 data was incorporated into the calculation to determine the average number of residential customers that would be added in 2007." To the contrary, this line of reasoning actually supports the fact that customer growth has slowed. Compared to the 16,672 residential customers added in 2004, the 2006 actual figure is a decline of 32% over the three-year period.

Q. How did PPL Electric project an increase of 9,805 residential customers?

A. PPL Electric employs econometric models to develop the forecast of residential customers. PPL Electric obtains historical and forecast data from MoodysEconomy.com on the number of households in Pennsylvania. The historical relationship of the number of PPL Electric customers to the number of households in Pennsylvania is calculated, and this historical relationship is extrapolated into the future to develop a forecast of the PPL Electric service area share of Pennsylvania households. This share of households then is regressed against the forecasted number of households in the state to develop the PPL Electric residential customer forecast.

Q. The future test year is now half over. How has the year-to-date number of new residential customers compared to last year?

A. PPL Electric's customer counts do not increase at a uniform rate throughout the year, mainly due to the seasonality of the construction industry. The majority of new customers tend to be added during the first half of the year, when new housing starts get underway. For 2007, PPL Electric projects 9,805 new residential customers. Through June 2007, the Company has actually added 7,235 customers, or 74% of the projected 2007 total. By comparison, for 2006, PPL Electric added 11,476 customers, of which 10,538, or 92%, were added through June. Given

these figures, the forecasted increase of 9,805 for 2007 is very optimistic, and the actual number may be much lower. Certainly, there is no basis for Mr. Kubas' 11,653 figure.

Q. Does this conclude your testimony?

A. Yes it does.

PPL ELECTRIC UTILITIES CORPORATION

Exhibit DRW 1-Revised

2006 Annualization of Distribution Revenues

2006 Annualization of Transmission Revenues

2007 Annualization of Distribution Revenues

2007 Annualization of Transmission Revenues

Witness: David R. Woodruff

PPL Electric Utilities
2006 Annualization

Distribution Only

(1)	(2)	(3)	(4) (2) / (3)	(5) (25) on "KWH"	(6) (4) * (5)	(7)	(8) (26) on "KWH"	(9) (7) * (8)	(10) (5) + (8)	(11) (6) + (9)
Rate	Revenue $	Sales kWh	Average Price $/kWh	Sales Adjustment - Customer Usage kWh	Customer Usage Revenue $	Incremental Price $/kWh	Sales Adjustment - Customer Growth kWh	Customer Growth Revenue $	Total Sales Adjustment kWh	Total Revenue Adjustment $
RS	$ 376,941,156	13,339,389,613	$ 0.0283	(5,354,910)	$ (151,318)	$ 0.0188	64,087,476	$ 1,202,144	58,732,566	$ 1,050,826
RTS	$ 3,743,951	363,491,518	$ 0.0103	(7,872,507)	$ (81,087)	$ 0.0009	(1,368,862)	$ (1,216)	(9,241,369)	$ (82,303)
RTD	$ 134,549	4,755,628	$ 0.0283	(76,089)	$ (2,153)	$ 0.0175	(26,919)	$ (472)	(103,008)	$ (2,625)
GS-1	$ 75,555,853	1,918,334,748	$ 0.0394	(14,216,728)	$ (559,942)	$ 0.0224	4,921,283	$ 110,061	(9,295,445)	$ (449,881)
GS-3	$ 115,379,588	8,565,176,555	$ 0.0135	(7,010,900)	$ (94,442)	$ 0.0072	9,222,263	$ 66,459	2,211,363	$ (27,983)
LP-4	$ 31,755,199	5,849,944,666	$ 0.0054	4,380,273	$ 23,777	$ 0.0041	72,114,702	$ 296,834	76,494,975	$ 320,611
ISP	$ 1,824,688	319,477,861	$ 0.0057	(2,525,683)	$ (14,425)	$ 0.0073	(5,704,962)	$ (41,792)	(8,230,645)	$ (56,217)
LP-5	$ 1,972,435	3,053,220,058	$ 0.0006	(47,697,280)	$ (30,813)	$ 0.0004	-	$ -	(47,697,280)	$ (30,813)
IST	$ 1,335,424	1,880,611,188	$ 0.0007	22,827,062	$ 16,210	$ 0.0018	-	$ -	22,827,062	$ 16,210
L5S	$ 49,133	4,639,000	$ 0.0106	(387,333)	$ (4,102)	$ 0.0001	-	$ -	(387,333)	$ (4,102)
LP-6	$ 177,316	427,174,000	$ 0.0004	(2,063,333)	$ (856)	$ 0.0003	53,396,750	$ 17,243	51,333,417	$ 16,387
LPEP	$ 463,457	62,010,000	$ 0.0075	348,017	$ 2,601	$ 0.0015	-	$ -	348,017	$ 2,601
ISM	$ 575,878	438,159,287	$ 0.0013	20,540,375	$ 26,996	$ (0.0000)	-	$ -	20,540,375	$ 26,996
IS-1	$ 30,600	1,664,560	$ 0.0184	61,799	$ 1,136	$ -	-	$ -	61,799	$ 1,136
BL	$ 269,184	6,164,221	$ 0.0437	(80,375)	$ (3,510)	$ 0.0430	75,173	$ 3,230	(5,202)	$ (280)
SA	$ 3,472,345	23,012,817	$ 0.1509	-	$ -	$ 0.1509	-	$ -	-	$ -
SM	$ 711,868	4,529,310	$ 0.1572	(22,197)	$ (3,489)	$ 0.1572	(115,544)	$ (18,160)	(137,741)	$ (21,649)
SHS	$ 11,769,365	49,583,975	$ 0.2374	(2,868,928)	$ (680,975)	$ 0.2374	297,674	$ 70,657	(2,571,254)	$ (610,319)
SE	$ 1,567,703	34,721,839	$ 0.0452	2,000,946	$ 90,343	$ 0.0452	1,132,234	$ 51,121	3,133,180	$ 141,464
TS	$ 22,725	319,584	$ 0.0711	(10,084)	$ (717)	$ 0.0711	-	$ -	(10,084)	$ (717)
SI-1	$ 15,456	82,588	$ 0.1871	(1,867)	$ (349)	$ 0.1871	-	$ -	(1,867)	$ (349)
GH-1	$ 5,713,453	274,540,543	$ 0.0208	7,087,718	$ 147,502	$ 0.0167	(2,798,428)	$ (46,626)	4,289,289	$ 100,876
GH-2	$ 1,338,154	61,858,689	$ 0.0216	(1,339,405)	$ (28,975)	$ 0.0133	(420,547)	$ (5,582)	(1,759,952)	$ (34,556)
Total	$ 634,819,480	36,682,862,248		(34,281,432)	$ (1,348,588)		194,812,294	$ 1,703,901	160,530,861	$ 355,313

PPL Electric Utilities
2007 Annualization

Distribution Only

(1)	(2)	(3)	(4) (2) / (3)	(5) (25) on "KWH"	(6) (4) * (5)	(7)	(8) (26) on "KWH"	(9) (7) * (8)	(10) (5) + (8)	(11) (6) + (9)
Rate	Revenue $	Sales kWh	Average Price $/kWh	Sales Adjustment - Customer Usage kWh	Customer Usage Revenue $	Incremental Price $/kWh	Sales Adjustment - Customer Growth kWh	Customer Growth Revenue $	Total Sales Adjustment kWh	Total Revenue Adjustment $
RS	$ 389,428,996	13,782,978,000	$ 0.0283	62,775,787	$ 1,773,689	$ 0.0175	56,566,444	$ 988,197	119,342,231	$ 2,761,885
RTS	$ 3,704,805	385,602,000	$ 0.0096	(214,973)	$ (2,065)	$ (0.0004)	(1,128,224)	$ 443	(1,343,197)	$ (1,622)
RTD	$ 137,526	5,013,000	$ 0.0274	21,430	$ 588	$ 0.0162	(28,810)	$ (466)	(7,381)	$ 122
GS-1	$ 75,277,490	1,949,520,000	$ 0.0386	(3,466,091)	$ (133,837)	$ 0.0112	9,873,247	$ 111,056	6,407,157	$ (22,781)
GS-3	$ 116,047,630	8,693,918,000	$ 0.0133	22,994,658	$ 306,936	$ 0.0049	17,510,017	$ 86,374	40,504,675	$ 393,310
LP-4	$ 30,559,230	5,868,659,000	$ 0.0052	(13,702,319)	$ (71,351)	$ 0.0044	73,499,583	$ 321,704	59,797,264	$ 250,353
ISP	$ 1,817,693	343,821,000	$ 0.0053	3,117,262	$ 16,480	$ 0.0044	-	$ -	3,117,262	$ 16,480
LP-5	$ 1,719,341	3,194,563,000	$ 0.0005	(12,603,034)	$ (6,783)	$ 0.0007	14,789,644	$ 9,843	2,186,609	$ 3,060
IST	$ 739,078	1,980,277,000	$ 0.0004	33,374,210	$ 12,456	$ (0.0002)	-	$ -	33,374,210	$ 12,456
L5S	$ 45,370	6,581,000	$ 0.0069	(57,881)	$ (399)	$ 0.0071	-	$ -	(57,881)	$ (399)
LP-6	$ 139,013	363,650,000	$ 0.0004	(9,497,044)	$ (3,630)	$ 0.0004	-	$ -	(9,497,044)	$ (3,630)
LPEP	$ 331,971	72,000,000	$ 0.0046	620,000	$ 2,859	$ -	-	$ -	620,000	$ 2,859
ISM	$ 537,964	426,000,000	$ 0.0013	4,821,148	$ 6,088	$ -	-	$ -	4,821,148	$ 6,088
IS-1	$ 31,633	1,447,000	$ 0.0219	26,327	$ 576	$ 0.0219	-	$ -	26,327	$ 576
BL	$ 281,756	6,468,000	$ 0.0436	(101,714)	$ (4,431)	$ -	-	$ -	(101,714)	$ (4,431)
SA	$ 3,393,093	22,878,000	$ 0.1483	-	$ -	$ 0.1483	-	$ -	-	$ -
SM	$ 890,277	5,699,000	$ 0.1562	208,490	$ 32,570	$ 0.1562	(88,129)	$ (13,767)	120,361	$ 18,802
SHS	$ 10,988,709	48,496,000	$ 0.2266	(3,007,551)	$ (681,481)	$ 0.2266	514,165	$ 116,505	(2,493,386)	$ (564,976)
SE	$ 1,399,587	35,699,000	$ 0.0392	2,206,692	$ 86,514	$ 0.0392	939,447	$ 36,831	3,146,140	$ 123,345
TS	$ 20,787	334,000	$ 0.0622	(2,745)	$ (171)	$ 0.0622	-	$ -	(2,745)	$ (171)
SI-1	$ 14,599	87,000	$ 0.1678	(556)	$ (93)	$ 0.1678	-	$ -	(556)	$ (93)
GH-1	$ 5,750,873	277,937,000	$ 0.0207	(2,094,018)	$ (43,328)	$ 0.0124	(2,268,256)	$ (28,229)	(4,362,274)	$ (71,557)
GH-2	$ 1,357,692	64,352,000	$ 0.0211	(110,761)	$ (2,337)	$ 0.0009	(483,648)	$ (442)	(594,409)	$ (2,778)
Total	$ 644,615,113	37,535,979,000		85,307,316	$ 1,288,848		169,695,479	$ 1,628,049	255,002,796	$ 2,916,897

PPL Electric Utilities
2006 Annualization

Transmission Only

(1)	(2)	(3)	(4) (2) / (3)	(5) (25) on "KWH"	(6) (4) * (5)	(7)	(8) (26) on "KWH"	(9) (7) * (8)	(10) (5) + (8)	(11) (6) + (9)
Rate	Revenue $	Sales kWh	Average Price $/kWh	Sales Adjustment - Customer Usage kWh	Customer Usage Revenue $	Incremental Price $/kWh	Sales Adjustment - Customer Growth kWh	Customer Growth Revenue $	Total Sales Adjustment kWh	Total Revenue Adjustment $
RS	$ 80,313,980	13,339,389,613	$ 0.0060	(5,354,910)	$ (32,241)	$ 0.0057	64,087,476	$ 368,060	58,732,566	$ 335,819
RTS	$ 2,186,776	363,491,518	$ 0.0060	(7,872,507)	$ (47,361)	$ 0.0058	(1,368,862)	$ (7,992)	(9,241,369)	$ (55,353)
RTD	$ 28,620	4,755,628	$ 0.0060	(76,089)	$ (458)	$ 0.0058	(26,919)	$ (156)	(103,008)	$ (614)
GS-1	$ 11,559,296	1,918,334,748	$ 0.0060	(14,216,728)	$ (85,666)	$ 0.0057	4,921,283	$ 28,145	(9,295,445)	$ (57,520)
GS-3	$ 51,232,323	8,565,176,555	$ 0.0060	(7,010,900)	$ (41,935)	$ 0.0059	9,222,263	$ 54,756	2,211,363	$ 12,821
LP-4	$ 35,013,869	5,849,944,666	$ 0.0060	4,380,273	$ 26,217	$ 0.0063	72,114,702	$ 455,850	76,494,975	$ 482,068
ISP	$ 1,942,369	319,477,861	$ 0.0061	(2,525,683)	$ (15,356)	$ 0.0064	(5,704,962)	$ (36,353)	(8,230,645)	$ (51,708)
LP-5	$ 18,384,691	3,053,220,058	$ 0.0060	(47,697,280)	$ (287,205)	$ 0.0059	-	$ -	(47,697,280)	$ (287,205)
IST	$ 11,508,407	1,880,611,188	$ 0.0061	22,827,062	$ 139,690	$ 0.0060	-	$ -	22,827,062	$ 139,690
L5S	$ 27,983	4,639,000	$ 0.0060	(387,333)	$ (2,336)	$ 0.0060	-	$ -	(387,333)	$ (2,336)
LP-6	$ 2,583,908	427,174,000	$ 0.0060	(2,063,333)	$ (12,481)	$ 0.0061	53,396,750	$ 323,765	51,333,417	$ 311,284
LPEP	$ 374,634	62,010,000	$ 0.0060	348,017	$ 2,103	$ 0.0061	-	$ -	348,017	$ 2,103
ISM	$ 1,673,027	438,159,287	$ 0.0038	20,540,375	$ 78,429	$ 0.0055	-	$ -	20,540,375	$ 78,429
IS-1	$ 10,005	1,664,560	$ 0.0060	61,799	$ 371	$ 0.0059	-	$ -	61,799	$ 371
BL	$ 37,573	6,164,221	$ 0.0061	(80,375)	$ (490)	$ 0.0061	75,173	$ 458	(5,202)	$ (32)
SA	$ 139,828	23,012,817	$ 0.0061	-	$ -	$ 0.0061	-	$ -	-	$ -
SM	$ 27,048	4,529,310	$ 0.0060	(22,197)	$ (133)	$ 0.0060	(115,544)	$ (690)	(137,741)	$ (823)
SHS	$ 297,410	49,583,975	$ 0.0060	(2,868,928)	$ (17,208)	$ 0.0060	297,674	$ 1,785	(2,571,254)	$ (15,423)
SE	$ 208,831	34,721,839	$ 0.0060	2,000,946	$ 12,034	$ 0.0060	1,132,234	$ 6,810	3,133,180	$ 18,844
TS	$ 1,934	319,584	$ 0.0061	(10,084)	$ (61)	$ 0.0061	-	$ -	(10,084)	$ (61)
SI-1	$ 521	82,588	$ 0.0063	(1,867)	$ (12)	$ 0.0063	-	$ -	(1,867)	$ (12)
GH-1	$ 1,637,354	274,540,543	$ 0.0060	7,087,718	$ 42,271	$ 0.0056	(2,798,428)	$ (15,617)	4,289,289	$ 26,654
GH-2	$ 372,221	61,858,689	$ 0.0060	(1,339,405)	$ (8,060)	$ 0.0059	(420,547)	$ (2,462)	(1,759,952)	$ (10,521)
Total	**$ 219,562,605**	**36,682,862,248**		**(34,281,432)**	**$ (249,885)**		**194,812,294**	**$ 1,176,361**	**160,530,861**	**$ 926,476**

PPL Electric Utilities
2007 Annualization

Transmission Only

(1)	(2)	(3)	(4) (2) / (3)	(5) (25) on "KWH"	(6) (4) * (5)	(7)	(8) (26) on "KWH"	(9) (7) * (8)	(10) (5) + (8)	(11) (6) + (9)
Rate	Revenue $	Sales kWh	Average Price $/kWh	Sales Adjustment - Customer Usage kWh	Customer Usage Revenue $	*Incremental* Price $/kWh	Sales Adjustment - *Customer* Growth kWh	Customer *Growth* Revenue $	Total *Sales* Adjustment kWh	Total *Revenue* Adjustment $
RS	$ 77,978,133	13,782,978,000	$ 0.0057	62,775,787	$ 355,158	$ 0.0059	56,566,444	$ 334,370	119,342,231	$ 689,528
RTS	$ 2,183,290	385,602,000	$ 0.0057	(214,973)	$ (1,217)	$ 0.0058	(1,128,224)	$ (6,537)	(1,343,197)	$ (7,754)
RTD	$ 28,378	5,013,000	$ 0.0057	21,430	$ 121	$ 0.0058	(28,810)	$ (168)	(7,381)	$ (47)
GS-1	$ 11,019,603	1,949,520,000	$ 0.0057	(3,466,091)	$ (19,592)	$ 0.0062	9,873,247	$ 61,417	6,407,157	$ 41,825
GS-3	$ 49,129,868	8,693,918,000	$ 0.0057	22,994,658	$ 129,944	$ 0.0062	17,510,017	$ 108,637	40,504,675	$ 238,581
LP-4	$ 33,140,323	5,868,659,000	$ 0.0056	(13,702,319)	$ (77,377)	$ 0.0060	73,499,583	$ 438,597	59,797,264	$ 361,220
ISP	$ 1,942,791	343,821,000	$ 0.0057	3,117,262	$ 17,614	$ 0.0048	-	$ -	3,117,262	$ 17,614
LP-5	$ 18,021,425	3,194,563,000	$ 0.0056	(12,603,034)	$ (71,097)	$ 0.0054	14,789,644	$ 79,213	2,186,609	$ 8,115
IST	$ 11,176,214	1,980,277,000	$ 0.0056	33,374,210	$ 188,356	$ 0.0047	-	$ -	33,374,210	$ 188,356
L5S	$ 37,197	6,581,000	$ 0.0057	(57,881)	$ (327)	$ 0.0062	-	$ -	(57,881)	$ (327)
LP-6	$ 2,055,141	363,650,000	$ 0.0057	(9,497,044)	$ (53,672)	$ 0.0060	-	$ -	(9,497,044)	$ (53,672)
LPEP	$ 406,884	72,000,000	$ 0.0057	620,000	$ 3,504	$ -	-	$ -	620,000	$ 3,504
ISM	$ 1,491,906	426,000,000	$ 0.0035	4,821,148	$ 16,884	$ -	-	$ -	4,821,148	$ 16,884
IS-1	$ 8,179	1,447,000	$ 0.0057	26,327	$ 149	$ 0.0062	-	$ -	26,327	$ 149
BL	$ 36,556	6,468,000	$ 0.0057	(101,714)	$ (575)	$ -	-	$ -	(101,714)	$ (575)
SA	$ 129,397	22,878,000	$ 0.0057	-	$ -	$ 0.0057	-	$ -	-	$ -
SM	$ 32,236	5,699,000	$ 0.0057	208,490	$ 1,179	$ 0.0057	(88,129)	$ (498)	120,361	$ 681
SHS	$ 274,327	48,496,000	$ 0.0057	(3,007,551)	$ (17,013)	$ 0.0057	514,165	$ 2,908	(2,493,386)	$ (14,104)
SE	$ 201,942	35,699,000	$ 0.0057	2,206,692	$ 12,483	$ 0.0057	939,447	$ 5,314	3,146,140	$ 17,797
TS	$ 1,889	334,000	$ 0.0057	(2,745)	$ (16)	$ 0.0057	-	$ -	(2,745)	$ (16)
SI-1	$ 492	87,000	$ 0.0057	(556)	$ (3)	$ 0.0057	-	$ -	(556)	$ (3)
GH-1	$ 1,570,988	277,937,000	$ 0.0057	(2,094,018)	$ (11,836)	$ 0.0062	(2,268,256)	$ (14,098)	(4,362,274)	$ (25,934)
GH-2	$ 363,742	64,352,000	$ 0.0057	(110,761)	$ (626)	$ 0.0062	(483,648)	$ (3,005)	(594,409)	$ (3,631)
Total	$ 211,230,901	37,535,979,000		85,307,316	$ 472,042		169,695,479	$ 1,006,150	255,002,796	$ 1,478,192

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00072155

PPL Electric Utilities Corporation

Statement No. 5-R

Rebuttal Testimony of Douglas A. Krall

Q. Please state your full name and business address.

A. My name is Douglas A. Krall. My business address is Two North Ninth Street, Allentown, Pennsylvania, 18101.

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

A. I am employed by PPL Electric Utilities Corporation ("PPL Electric" or the "Company"), a subsidiary of PPL Corporation. I work in the Asset Management Department of PPL Electric and my title is Manager – Regulatory Strategy.

Q. Have you provided testimony previously in this proceeding?

A. Yes, I have. I provided written direct testimony that was designated as Statement No. 5. I also provided Exhibit DAK 1.

Q. Please describe the purpose of your rebuttal testimony.

A. The purpose of my rebuttal testimony and Exhibits DAK 1-R and 2-R is to address issues raised by other parties regarding the following:

1. The Company's request to include plant held for future use in rate base or, in the alternative, to accrue AFUDC on that plant.
2. The Company's purchase of insurance to recover costs associated with storm-related damage.
3. The Company's proposal to implement energy conservation, energy efficiency, demand-side response, and consumer education programs for its customers.

4. Concerns raised by the Governor's Energy Independence Strategy.

5. Issues regarding class revenue allocation proposals of other parties.

6. Issues raised at the public input hearings.

In discussing these issues, I will address portions of the direct testimony of the following witnesses:

- Sustainable Energy Fund of Central Eastern Pennsylvania's ("SEF") witness Jennifer Hopkins.
- Richards Energy Group, Inc. ("Richards Energy") witness Frank Richards.
- Office of Trial Staff ("OTS") witness Janet Markovich.
- Office of Consumer Advocate ("OCA") witnesses Lafayette Morgan, Richard Galligan and David Parcell.
- Office of Small Business Advocate ("OSBA") witness Robert Knecht.
- PPL Industrial Customer Alliance ("PPLICA") witness Stephen Baron.
- Department of Defense ("DOD") witness Kenneth Kincel.

Plant Held for Future Use

Q. Please describe PPL Electric's request in this proceeding.

A. PPL Electric rate base in this proceeding claim included $2,212,678 related to distribution plant held for future use. In the alternative, PPL Electric requested approval to accrue a return equivalent to the applicable AFUDC rate on these investments and to include the accrued amount as part of its distribution plant in-service at the time such plant is placed into service.

Q. On page 5 of his testimony, OCA witness Lafayette Morgan recommends that the Commission accept PPL Electric's alternative request and allow the Company to accrue AFUDC on those specific parcels of land subject to normal regulatory oversight at the time the Company requests such plant be placed into service. Does the Company accept this proposal?

A. Yes, the Company does.

Storm Insurance

Q. Please summarize the Company's claim in this case for storm insurance premiums.

A. In June 2006, the Company was able to obtain insurance for a portion of the damage resulting from storms on its system. The insurance that PPL Electric has obtained consists of two parts: Primary coverage through its affiliate, PPL Power Insurance Ltd. ("PPL Power"), and secondary coverage through the re-insurance market. Under this coverage, PPL Electric is responsible for a total of $7.5 million for all storms during a one-year period with a maximum exposure of $5 million per storm within the $7.5 million total. The premium for the first layer of coverage is $6 million and the premium for the reinsurance is $1,560,000. The future test year budget reflects the payment of the insurance premiums for a full twelve months of coverage for the distribution system. In addition, the 2007 budget includes $7.5 million, the amount of the deductible under the insurance policy, for the cost of storm damage not covered by insurance.

On June 5, 2007, the Company renewed the storm insurance for the period June 5, 2007 through June 1, 2008 at the same premiums.

Q. Please describe the concerns raised by OCA witness Morgan.

A. Mr. Morgan asserts that the insurance coverage the Company has obtained is not beneficial to customers and, therefore, the premiums should not be recovered from customers through rates. Mr. Morgan also asserts that the Company has chosen to enter into a transaction with an affiliate that it considered to be unreasonable to enter into with a non-affiliate. I will respond to Mr. Morgan's contention that the coverage is not beneficial to customers and will propose an alternative ratemaking claim if the Commission were to disallow the Company's claim for the insurance premium. Mr. Novatnack will explain the need for storm damage insurance, the decision to place the first layer of coverage with an affiliate and the reasonableness of the annual premium.

Q. How do you respond to Mr. Morgan's assertion that this coverage is not beneficial to customers?

A. Mr. Morgan supports this assertion with a flawed interpretation of an example originally provided in my direct testimony (PPL Statement No. 5).

Q. Please elaborate on Mr. Morgan's interpretation of your example.

A. On pages 27 and 28 of PPL Statement No. 5, I provide an analysis of how the insurance coverage would have provided benefits to customers had it been in

effect during 2005. My conclusion (page 28, lines 3 – 5) is: "Customers would have paid a $5.7 million premium and, in exchange, received $12.1 million in storm restoration benefits." Mr. Morgan quotes my example and analysis verbatim, but concludes, instead, (page 28, lines 3-5): "Customers would have paid approximately $15.0 million for $12.1 million of insurance coverage."

Mr. Morgan's analysis contains two fundamental errors. First, it appears that Mr. Morgan has added the total insurance premium of $7.650 million to PPL's 2005 budget for normal storm expenses of $7.0 million to conclude that customers had paid "approximately $15 million". In fact, the portion of the insurance premium associated with distribution plant is only $5,749,000 as acknowledged by Mr. Morgan on his Schedule LKM-17. Thus, correcting Mr. Morgan's approach to reflect the correct insurance premium, PPL customers would have actually paid only $12,749,000. Second, and more fundamentally, Mr. Morgan understates the storm-related costs that PPL Electric incurred in 2005. As stated on page 27 line 14 of PPL Statement No. 5 and reiterated by Mr. Morgan on page 21 line 1 of his testimony, the Company incurred a total of $20.3 million in extraordinary storm-related costs as a result of a severe ice storm in January 2005. In addition, PPL Electric incurred additional storm damage expenses of $3.5 million as a result of less severe storms later in 2005. To properly reflect the expenses for ratemaking purposes, it is necessary to deduct capital and regular pay and benefits. Looking at only the ice storm, the amount for capital, regular pay, and regular benefits was $4.2 million leaving a net ice storm-related expense of $16.1

million – an amount that is $4 million larger than the $12.1 million quoted by Mr. Morgan.

Another way to analyze the benefit of the storm damage insurance for ratepayers is to consider its effect on revenue requirement. PPL Electric has proposed to recover $16.1 million of storm damage expenses caused by the severe ice storm in January 2005 through an amortization of extraordinary storm damage expenses. See PPL Electric St. 5, pp. 19-25. No party has opposed this ratemaking amortization. In addition, customers have paid $7 million, the amount of PPL Electric 2005 storm damage expense budget, for a total of $23.1 million. If storm damage insurance had been in effect in 2005, customers would have paid a total of $12,749,000 (comprised of the $7.0 million included in PPL Electric's 2005 budget for storm damage expense plus $5.749 million in distribution-related storm damage insurance premiums) to address storm damage. Thus, the appropriate analysis of the effect of the storm damage insurance compares revenue requirement with the storm insurance and without the storm insurance. Because no storm damage insurance was in effect in 2005, customers will pay $23.1 million (comprised of $7.0 million included in PPL Electric's 2005 budget for storm damage expense plus $16.1 million in extraordinary storm damage expenses that will be recovered through amortization). Thus, contrary to Mr. Morgan's assertion, if the storm insurance coverage had been in place in 2005, customers would have realized a significant benefit. They would have paid $10.351 million less in storm damage expenses ($23.1 million minus $12.749 million).

In addition, customers will benefit because, with storm damage insurance, there is a significant reduction in the frequency of petitions of PPL Electric requesting amortization of extraordinary storm damage expenses. With the insurance coverage, PPL Electric would experience extraordinary storm damage expenses that would be the subject of a petition for deferral and amortization only when total storm damage expenses substantially exceed the sum of the storm damage insurance annual aggregate deductible of $7.5 million and the annual aggregate coverage limits of $30 million.

Q. How do you propose the Commission consider the reasonableness of PPL Electric's storm insurance?

A. I believe that the proper approach is to compare the premium that customers pay for the coverage to the restoration benefits they receive on the occasion of a catastrophic event. As explained in the 2005 example that I provide and that Mr. Morgan reiterates without criticism, a premium of $5.7 million resulted in customers receiving $12.1 million in restoration benefits.

Q. If the Commission does not allow PPL Electric to recover in rates the cost of premiums for this insurance coverage, have you developed an alternative ratemaking claim for recovery of the Company's costs of storm restoration?

A. Yes. As discussed in my direct testimony (PPL Statement No. 5), PPL Electric's storm damage expense claims in this proceeding total $13.249 million, and consists of two separate components: (1) $7.5 million to reflect a normal level of

routine storm damage expense that is not covered by insurance and (2) $5,749,000 for the distribution-related portion of the storm damage insurance premium designed to recover costs associated with larger, non-routine storm damage expense. This $13.249 million claim is supported by the fact that over the past five years the Company has incurred actual average annual distribution operation and maintenance costs, excluding regular salaries and wages and related benefits of approximately $12.8 million in storm restoration costs. Mr. Morgan proposes to disallow the storm damage insurance premium, which would leave PPL Electric with only $7.5 million in rates to cover prospective storm damage expense. This amount is plainly inadequate given the five-year average expense of $12.8 million. In other words, it the storm damage insurance premium is disallowed, the Company's claim for prospective cost recovery must be increased to reflect a reasonable estimate of future storm damage expense. The five-year average of actual historic storm damage, in my view, provides a reasonable basis for establishing an appropriate ratemaking allowance in this proceeding. I believe such a claim clearly is appropriate because it simply allows the Company to recover a reasonable estimate of its future costs of repairing damage caused by storms and restoring service to its customers. Without such a revision to PPL Electric's storm expense claim, Mr. Morgan's proposed adjustment would preclude the Company from fully recovering a reasonable level of storm-related expenses. Under his approach, the Company would recover in rates less than half of its actual storm-related costs (based on a five-year average), but could not obtain storm damage insurance for the shortfall because

it could not recover in rates the premiums for such insurance. The Commission should either approve PPL Electric's primary claim of $13.249 million for storm damage with related increases, or in the alternative, approve a revised claim of $12.8 million to reflect actual average storm damage costs.

Q. Your comparisons above relate to operation and maintenance expense. Does the insurance cover capitalized repairs and replacement of distribution facilities caused by storms?

A. Yes, it does. Coverage of capital losses also reduces revenue requirement, rate base, income taxes and depreciation. These reductions also benefit rate payers.

Demand-Side Management and Conservation/Efficiency Programs

Q. Please describe the Company's proposal regarding demand-side management and consumer education programs.

A. The Company is seeking approval to pursue the development and implementation of five new programs related to demand-side management education. These programs, taken together, have a cost of $2.7 million in the 2007 test year. The Company also is proposing to establish an Energy Efficiency Rider to recover the ongoing costs associated with these programs. Finally, the Company is proposing a broad consumer education program to help customers better understand their electricity usage and bills, and pursue energy efficiency and conservation measures. A total of $4.4 million is included in the 2007 test year for this purpose.

Q. What concerns have parties raised relative to the five programs that PPL Electric has proposed?

A. In general, parties have not objected to the programs the Company proposed nor have they suggested additional programs. OCA witness Galligan lists (on pages 29 and 30) considerations that he believes should be addressed in the development of time of use pricing programs and recommends that the Commission order PPL Electric to adopt procedures that provide for the participation of OCA and other interested parties in the development of such programs. Richards Energy witness Richards (on page 3) expresses support for the Company's proposed program to develop time of use pricing for Residential Thermal Storage ("RTS") customers and suggests that changing the response time for RTS customers might work well if the process can be automated. SEF witness Hopkins (on page 9) agrees that consumer education is an important step and recommends that the Company conduct a small business loan guarantee program in partnership with SEF.

Q. How does the Company respond to the concerns raised by Mr. Galligan?

A. The Company agrees with Mr. Galligan that numerous factors must be considered in developing time of use pricing programs and acknowledges that his list includes a number of these factors. It has always been the Company's intent to file these programs with the Commission for review, and such review presumably would include an opportunity for interested parties to comment.

However, in order to gain additional information earlier in the process, the Company is willing to seek input prior to the filing of these programs with the Commission.

Q. How does the Company respond to the concerns raised by Mr. Richards?

A. RTS equipment was designed to respond to specified on-peak and off-peak periods. It, therefore, may be possible to modify that equipment to respond to different on-peak and off-peak time periods. As Mr. Homa has described, the Company is attempting to design a new pricing option for RTS customers. The Company agrees with Mr. Richards that automation could be a desirable feature of such a program and will consider incorporating that feature into the program.

Q. How does the Company respond to the concerns raised by Ms. Hopkins?

A. The Company agrees with Ms. Hopkins' statement that "(c)reating a more informed customer is an important step in behavior modification associated with energy efficiency and conservation." The Company's programs are aimed, in the first instance, at educating customers on the issues they may face and options that may be available to them. The Company also recognizes that the value of education is limited if there are, in fact, no options to pursue, or there are impediments that make it difficult for customers to pursue available options. The small business loan guarantee program that Ms. Hopkins describes is not primarily about educating customers, but more about eliminating impediments. As the Company envisions the process, small business customers would, first,

need to be aware of the issues that they may face in the purchase of electricity in the future. Second, they need to be aware of the possible actions that they can undertake. Finally, they should be given assistance in pursuing actions. A small business loan guarantee program would serve the customer who is aware, has decided to pursue an energy efficiency investment (such as weatherization or more efficient heating equipment), but needs financial assistance to make this happen.

Q. Why has the Company not included such a program at this time?

A. The Company believes loan programs, both for business and residential customers, can have significant merit. However, in this proceeding, the Company is proposing an initial set of programs, primarily focused on education that can be implemented relatively quickly and simply. The Company views loan guarantees as more of a third step to address implementation needs. As noted in my direct testimony (PPL Statement No. 5 page 15, lines 14 through 18), the Company's proposed Energy Efficiency Rider is intended to provide a cost recovery mechanism under which programs can be revised and new programs added in a timely manner with appropriate Commission review. Development and implementation of a small business loan guarantee program is just the type of additional program that the Company had in mind when it proposed the Energy Efficiency Rider.

Q. Would the Company consider undertaking such a program in partnership with SEF?

A. The Company has had initial discussions dating back to the Fall of 2006 with SEF regarding such a program and believes that SEF may be an appropriate partner. However, the Company has an obligation to provide such an opportunity to all qualified organizations. Based on each organization's expertise, staffing, program proposals and bid price, the Company would select the best candidate to implement the program. Of course, SEF would be invited to participate in that process. PPL Electric, however, does not believe that such a selection should be mandated in the context of a base rate proceeding without giving other potential candidates notice and an opportunity to participate.

Q. What concerns have parties raised relative to the funding of the programs and the establishment of the Energy Efficiency Rider?

A. Several parties take exception to PPL Electric's proposal to institute an Energy Efficiency Rider to recover costs associated with the development of the demand-side management programs. OCA witnesses Morgan and Galligan both recommend (Morgan at page 25 and Galligan at page 30) that the cost of demand-side management programs be recovered through base rates and not through a reconcilable rider. OSBA witness Knecht (on page 22) recommends that the Commission limit recovery to $2.7 million by either including those costs in rates on a non-reconcilable basis or by setting a cap of $2.7 million on reconcilable amounts. Mr. Knecht also recommends that, if the Commission

approves recovery of program costs through a separate rider, it should establish separate charges for residential and small business customers that reflect the costs of providing programs to those separate classes of customers. Richards Energy witness Richards recommends (on pages 8 and 9) that cost recovery should be capped and that PPL Electric should provide matching funds of its own to recognize that the Company will benefit from not having to reinforce or build new distribution facilities.

Q. How do you respond to these concerns?

A. At the outset, the Company is pleased that parties have accepted the Company's proposal to spend $2.7 million per year on specific programs to aid customers in understanding and undertaking demand-side management, energy efficiency, and energy conservation programs that will ultimately benefit those customers. As the industry approaches the end of caps on generation rates and the likelihood of higher and more volatile prices, such programs are vitally important to customers. In addition, as explained elsewhere, the Company has made a very substantial investment in "smart metering" infrastructure. This initiative will provide a significant opportunity for customers to use energy more efficiently and reduce their overall energy costs, but this will occur only if customers are knowledgeable about this equipment and how to use it to their advantage. Moreover, as explained above, there is substantial uncertainty about both the type and amount of expenditures which will be required in this area. The Energy

Efficiency Rider is a critical mechanism to provide timely cost recovery for these important programs.

The Company believes that its proposal to fund these programs and recover costs through a reconcilable Energy Efficiency Rider is appropriate based on the following considerations:

1. In its Order regarding Policies to Mitigate Potential Increases in Electricity Prices entered at Docket No. M-00061957 on May 17, 2007, the Commission acknowledged that while virtually all parties offering comments in the proceeding "agreed that consumer education is an essential element of any strategy to mitigate the effect of price increases", there was also "significant disagreement over the size and scope of these efforts." (Order at page 5) The Company believes that a rider that can be reset as necessary in the context of the consumer education plan that the Order also requires be filed by each Electric Distribution Company is a good practical approach to the issue of uncertainty and one that is consistent with Commission rules regarding the use of such riders.
2. A reconcilable rider assures customers that they will not be overcharged and assures the Company that it will not under-recover its costs.

The proposals of Messrs. Morgan, Galligan, and Knecht to recover these costs through base rates (or, in the alternative proposed by Mr. Knecht, to cap reconciliation at $2.7 million) might be appropriate if the scope of consumer education and programs were fully known. This, however, is not the case, and using a reconcilable rider is more appropriate given that the Commission itself

acknowledges significant uncertainty as to the size and scope of consumer education efforts.

With regard to the alternative proposal of Mr. Knecht to establish separate Energy Efficiency Riders for residential and small commercial customers, the Company believes that many of its proposed programs will be applicable to both residential and commercial customers and that the establishment of separate charges therefore is unnecessary. Mr. Knecht points out in defense of his argument for separate charges that one of the five programs will be specifically applicable to customers on the Company's Rate Schedule RTS. However, it is a distinct possibility that this effort, although initially identified with an existing off-peak residential program, might result in a rate that will be advantageous to additional groups of customers, including small commercial customers currently served under commercial off-peak rates. Furthermore, the RTS program is only one of five programs and only accounts for about 16% of the $2.7 million projected to be spent in 2008.

Mr. Richards justifies his proposal that the Company provide matching funds for consumer education and consumer programs based on his belief that the Company will benefit "by not having to reinforce or build new distribution facilities." Mr. Richards is incorrect for two reasons. First, while Mr. Richards is theoretically correct that demand reduction programs can potentially delay the need to upgrade the peak load capacity of the distribution system, this is clearly not the primary purpose of these programs. Second, in any event, the beneficiary of such delays is not the Company, but rather customers. By

delaying potential additions to rate base, customers will not experience the inclusion of those additions in rate base and the recovery of associated costs through rate increases until a later date. There is no basis to conclude that the Company's shareholders should make a matching contribution to demand-side programs.

Q. What concerns have parties raised relative to the Company's consumer education program and the request to include $4.4 million in base rates?

A. Two parties take exception with the amount to be included in base rates. OTS witness Markovich recommends (on page 9) that the $4.4 million expense be reduced to an allowance of $2.4 million. OCA witness Morgan (on pages 15 and 16) recommends that $3.3 million of the $4.4 million that is associated with television advertising be normalized over three years and that $400,000 be identified as institutional advertising and removed from the test year claim. SEF witness Hopkins recommends (on pages 8 and 9) that a portion of the $4.4 million be allocated to an existing proven solar education program.

Q. How do you respond to the recommendations of OTS and OCA for reductions associated with the television advertising within the $4.4 million the Company has requested?

A. Both Ms. Markovich and Mr. Morgan recommend adjustments based on their belief that the television advertising component of the $4.4 million program is related to the introduction of the new website and meter data management

capabilities and, therefore, need not be repeated in subsequent years. Mr. Morgan arrives at an adjustment he believes to be appropriate by spreading the television advertising cost for a single year over three years. Ms. Markovich also expresses the belief that on-going costs should be less than the initial costs to introduce a new program and, on that basis, recommends that $2.0 million be removed from the requested $4.4 million.

As stated in my direct testimony (page 18 line 4 through page 19 line 8), the Company anticipates a significant need for consumer education funds during and beyond 2007, and believes that these needs justify an expense allowance of $4.4 million per year. Mr. Morgan references the Company's response to Question 13 of Interrogatories of the Office of Consumer Advocate, Set VII, dated June 1, 2007, as indicating that the Company only anticipates spending $3 million and that it provides no budget amounts for 2008 and 2009. Attached, as Exhibit DAK1-R is a copy of the Company's response to the question referenced by Mr. Morgan. Based upon a review of the Company's response to this interrogatory, it is apparent that Mr. Morgan misinterpreted the response. The response clearly indicates that PPL Electric expects to spend $4.4 million annually for customer education on the capabilities of the meter data management system in both 2008 and 2009. It may be technically correct that the Company does not have detailed budget amounts for customer education for 2008 and 2009, but that is simply because the Company does not yet have approved budgets for those years. If the Company were finalizing budgets for 2008 and 2009 at this time, I anticipate

that the budgets would reflect at least $4.4 million in expenses for educating customers regarding the meter data management system.

Finally, and more generally, I would note that the Company has made a very substantial investment, approximately $170 million, in Advanced Meter Reading and Advanced Meter Infrastructure systems. While customers are already receiving substantial benefits from these systems in terms of avoided operating costs (elimination of manual meter reading, more efficient response to customer inquiries, etc.), significant additional benefits associated with managing their electricity use and costs will only be achieved if customers know about the capabilities of these systems and utilize them to the fullest extent possible. In my view, it is very short sighted to cut back on educating customers about these important systems and programs. This is particularly true where it is increasingly clear that customers will face significant increases in the generation component of rates when rate caps expire at the end of 2009. This point is demonstrated by the results of PPL Electric's recent procurement of the first one-sixth of the generation supply it needs in 2010 for residential, small commercial, and small industrial customers who do not choose a competitive supplier. If the prices paid in this supply purchase were to be the same for the remaining five purchases, the average residential customer's monthly bill would increase about 29 percent over 2009 levels, while small commercial and industrial bills would increase on the order of 18 percent to 37 percent over 2009 levels.

Q. How do you respond to Mr. Morgan's comment that $400,000 in institutional advertising should be deleted from the $4.4 million request?

A. Although no specific reference is provided in his testimony, the Company believes that Mr. Morgan's assertion regarding the $400,000 amount is based on the Company's response to question RE-62-D of Interrogatories of the Office of Trial Staff, Set X, dated April 23, 2007. A copy of the Company's response is provided as Exhibit DAK 2-R. The $400,000 amount identified as "Institutional" in Part A of the response was for a short television ad that was recut from television ads that were originally produced in 2004 and aired in 2004 and 2005. The purpose of this recut ad was to serve as an introduction to the energy conservation and efficiency messages that began airing in June. The Company would not have spent money on editing this ad and for air time had it not been for the energy conservation and efficiency messages that were to air in June. Consequently, while those expenses are labeled in this response as "Institutional", that does not change the Company's belief that they are an essential element of an effective consumer education plan. It is true that the Company does not plan to reair these introductory messages in 2008 and 2009. However, the Company would use that $400,000 per year for new consumer education messages. As I stated earlier, PPL Electric expects to spend $4.4 million annually for customer education on the capabilities of the meter data management system in both 2008 and 2009.

Q. How do you respond to Ms. Hopkins recommendation that a portion of the $4.4 million program be earmarked for the SEF Solar Scholars Program?

A. The Company's concerns regarding this proposal are similar to those I discussed earlier regarding SEF's proposed small business loan guarantee program. While the proposed program may have significant merit, the Company believes that it has an obligation to its customers and to the Commission to perform due diligence on whatever program and partner it might propose. In proposing this program in the context of a base rate proceeding, SEF is, in effect, making that due diligence the responsibility of the Commission. The Company does not believe that is an appropriate role for the Commission, nor is it fair to other entities who may wish to be considered for this program but who are not parties in this proceeding.

Concerns raised by the Governor's Energy Independence Strategy

Q. OCA witness David C. Parcell disagrees with your concerns regarding the potential impact of the Governor's Energy Independence Strategy on PPL Electric. What is your response?

A. Mr. Parcell appears to miss the fundamental point that I was trying to make in my discussion of the Energy Independence Strategy. The real concern is the level of uncertainty engendered by that strategy and other legislative initiatives surrounding it. Since I prepared my direct testimony (PPL Statement No. 5), the Pennsylvania General Assembly passed two energy-related bills as part of the budget package and the Governor has signed them into law. I will not attempt a

comprehensive analysis of those bills, but will mention several provisions in House Bill No. 1203 that could create substantial regulatory uncertainty in Pennsylvania. House Bill No. 1203 amends the Alternative Energy Portfolio Standards Act ("AEPS Act"). First, it modifies the definition of force majeure to require Electric Distribution Companies to show that they have made a "good faith" effort to acquire sufficient alternative energy to comply with their AEPS Act obligations before the Commission can make a force majeure determination. Good faith effort is defined to include, but not be limited to, four specific strategies to acquire alternative energy. A fifth acquisition strategy, which the Commission may require, is added later in the definition. It is not clear from the legislation whether all five approaches will be required to meet the "good faith" standard or whether additional approaches also will be necessary. These questions are important because under the Commission's proposed AEPS regulations, alternative compliance payments can be recovered through rates only if the Commission has made a force majeure determination. The result is additional uncertainty regarding exactly what will be required to comply with the AEPS Act.

Q. Do you have other examples of how House Bill No. 1203 will create regulatory uncertainty in Pennsylvania?

A. Yes. The bill significantly increases the amount of solar resources that must be acquired to comply with the AEPS Act. The availability and cost of those resources are completely unknown. The bill also requires Electric Distribution

Companies to accommodate net metering installations and virtual meter aggregation for customer-generators. Again, the financial impacts of these requirements are unknown.

Q. Mr. Parcell dismisses these concerns because he contends that they will not affect PPL Electric until after the end of the rate caps. Do you agree?

A. No. Some of these changes could affect PPL Electric immediately. For example, one of the methods for demonstrating "good faith" in the force majeure context is the purchase and banking of alternative energy credits during the transition period. Implementation of that alternative would require PPL Electric to expend funds in the 2007 to 2009 time period which it may never recover or may not recover until the end of 2010. Similarly, the net metering and meter aggregation obligations could increase PPL Electric's costs and decrease its revenues in the years before the end of the rate caps. More importantly, even if the direct financial effects of these changes are not incurred until after the end of the rate cap, the uncertainty created by the changes exists now and is likely to increase over the next several years.

Q. Mr. Parcell also contends that using the provisions of the Energy Independence Strategy as justification for increasing retail electric rates would be contrary to the intention of the strategy. How do you respond?

A. First, I would just note that many provisions of the strategy will increase retail electric rates. Examples include the increase in solar resource requirements

under the AEPS Act and the obligation to accommodate net metering and meter aggregation that I discussed earlier. But, more importantly, the intention of the strategy, as its name implies, is to achieve energy independence. One way to achieve energy independence is to ensure that electric utilities in the Commonwealth have the financial wherewithal to invest in the necessary transmission infrastructure, comply fully with the AEPS Act, meet their default service obligations and continue to provide safe and reliable electric service. Utilities can remain financially strong only if they are allowed to recover, on a full and current basis, all reasonable costs of doing business, including their risk-adjusted cost of capital. Therefore, in my opinion, proper recognition of the risks associated with the Energy Independence Strategy is fully consistent with the intention of that strategy

Q. Finally, do you believe these risks you describe are likely to increase or decrease over the next several years?

A. I believe that they definitely will increase. In Pennsylvania, the Governor has called a special legislative session beginning September 17, 2007, to discuss energy issues. It is likely that additional legislation will result from that session. Of course, it is impossible to predict what bills may be introduced or passed. Suffice it to say that over the past month bills were introduced that would significantly restrict an Electric Distribution Company's procurement of default service supply; create a new category of resources under the AEPS Act; add a systems benefit charge to customer bills for 30 years; and require the phase-in of

certain generation rate increases. Any of these items, or new initiatives, could become law before the end of the year. The result will be increased uncertainty and risk.

Class Revenue Allocation

Q. Has the Company changed its proposed class revenue allocations on rebuttal?

A. Yes. The changes in allocation among classes are driven by the changes in distribution rates resulting from the Remand Settlement. PPL Electric is continuing to allocate its proposed revenue increases in this proceeding with the goal of moving each rate schedule in this case one-half of the way to full cost of service, as measured by indexed rate of return. The only constraint upon this movement is that no rate schedule would receive a distribution rate increase more than twice the system average distribution percentage increase.

As explained in greater detail by Mr. Kasper, the Remand Settlement generally increased rates, and indexed rates of return, at present rates for schedules with below system average rates of return, and generally decreased rates, and indexed rates of return, at present rates for schedules with above-system average rates of return. In rebuttal, the Company has recomputed the increases and decreases necessary to move each schedule one-half of the way to the system average rate of return.

As Mr. Kasper explains, three rate schedules, RTS, SL/SA and LP-6, are subject to the two times system average constraint that I described in my direct testimony. The RTS and street lighting schedules (SL/SA) were constrained in

the Company's original rate design, and continue to be constrained under the revised rate design. Rate LP-6 became constrained under the revised rate design. Rate LP-6 became constrained following the Remand Settlement, as the revised rates, when applied to test year sales, produced a negative rate of return. The application of the constraint is designed to give appropriate consideration to principles of gradualism. I directed Mr. Kasper to allocate the deficiency for these three schedules (the difference between the capped revenue increases and the revenue increase that would have been produced without the application of the constraint) in the following manner. The RTS deficiency is allocated to the RS rate schedule class. The LP-6 deficiency is allocated to all rate schedules taking service at 69 kV or above. Finally, the street lighting deficiency is allocated to all customer rate schedules. I directed this revised allocation of the deficiencies to spread the cost most equitably; the RTS and LP-6 deficiencies are kept within their respective customer classes (residential and large commercial and industrial), and street lighting deficiencies are spread to all rate schedules, as all customers share the use of street lights and, indirectly, receive the benefit of lower street lighting costs through lower taxes.

Q. Why didn't the Company propose to move all rate schedules to full cost of service immediately?

A. Moving immediately to full cost of service would have required very large rate increases to the major rate schedules. For example, moving Rate Schedule RS, under which most residential customers are served, to full cost of service would

have required a 26.9 percent distribution rate increase. Such a move would have required correspondingly large rate decreases for other rate schedules. And, on an absolute basis, it would have required a residential rate increase of $104 million, far in excess of the total $77 million residential rate increase requested in this proceeding. Such increases are not reasonable, in my opinion, and certainly are not required by the Lloyd decision, which affirms that gradualism is an appropriate consideration in rate design. As explained in my direct testimony (PPL Statement No. 5), the Company's proposed revenue allocation has not allowed gradualism to "trump" cost of service; rather, gradualism has been used to temper the movement to full cost of service over a specific and reasonable time period.

Q. Please summarize the class revenue allocation proposals of other parties.

A. OCA appears to agree conceptually with the Company's general proposal to move all rate classes half way to the system average rate of return in this proceeding. OCA's disagreement relates to which cost of service study, the Company's or OCA's, should be used to define movement toward cost. Mr. Kleha will be responding to issues concerning the correct cost of service study to be used in this proceeding. I note that OCA's proposal results in a lower increase to residential customers than the Company's proposal, and greater revenue requirements allocated to the large customer classes.

OSBA also generally concurs with PPL Electric's methodology, based upon the Company's cost of service study. OSBA expresses concern about the

degree of movement for the GS-1, GS-3 and LP-4 rate classes, and proposes what it describes as a "revenue neutral" reallocation from LP-5, L5-S and LP-6 classes to GS-1, which is intended to decrease the indexed rate of return for the GS-1 class.

DOD's overriding, or one might argue sole, focus is on reducing those classes with above system average rates of return to no more than 125% of system average, regardless of where the rate class's return is at present rates. As explained later, this proposal results in a substantially wider range of rate changes than proposed by the Company.

PPLICA's basic rate design proposal is to reduce dollar subsidies of all classes by 50%. This proposal differs from the Company's proposal because it looks to dollar subsidy amounts, and not indexed return differences, in allocating the rate increase. Though not as extreme as the DOD proposal, PPLICA's proposal also would give greater increases to the residential class and greater rate reductions to the large customer classes than would be produced by the Company's proposal.

In summary, PPL Electric's rate design proposal can be seen as being in the middle of other parties' proposals, with no particular bias intended to benefit one rate class over another.

Q. Please respond to OSBA's proposal to target relief to the GS-1 class.

A. OSBA observes that, as a result of the intervening rate changes resulting from the Remand Settlement, the rate changes originally proposed by the Company

for rate schedules LP-5, LP-6 and L5-S are no longer justified by the cost of service study results. PPL Electric agrees with these observations, and in the revised revenue allocation, which I described previously in my testimony, the rate changes for these classes have been changed consistent with the Company's proposal to move classes 50% toward indexed cost of service. Under the Company's revised proposal, Rate Schedule GS-1 following a large decrease in revenue requirement of $1.8 million under the Remand Settlement receives a very small increase in revenue requirement of $165,000 and moves halfway to system average. In the Company's view, this revision should satisfy OSBA's concerns.

Q. Please respond to DOD's rate design proposal.

A. As noted previously, Mr. Kincel's single focus is on reducing the indexed returns of all rate classes to no more than 125% of system average. Not surprisingly, this proposal is designed to provide substantial rate reductions to DOD's large usage customers.

The principal flaw in Mr. Kincel's methodology is that it does not give any real consideration to gradualism for the classes, primarily the residential classes that have to pay for the increased rate reductions proposed by DOD. Based upon Mr. Kincel's own calculations, residential customers' distribution rates would have to increase by $98 million, which is substantially more than the total $83 million increase originally requested in this proceeding.

Q. Does PPLICA's proposal also result in increases to residential customers that are greater than the total proposed rate increase?

A. Yes, although not as extreme as DOD's proposal, Mr. Baron's exhibits also demonstrate that his proposal would allocate more than 100% of the Company's proposed increase to the residential customers, in order to produce greater rate reductions for larger customers. In addition, PPLICA's proposal would result in an increase of 42% to street lighting customers, many of which are municipal customers. I note that the Rate Schedule RTS customers would experience an approximately 131% increase, as shown in Mr. Baron's exhibits, if not for the PPLICA decision to modify its proposal of reducing dollar subsidies by 50% by grouping together the RTS class with the RS and RTD classes.

Q. At page 16 of his testimony, Mr. Baron criticizes the Company's use of indexed returns arguing that, in some instances, this approach could result in increased dollar subsidies to certain classes. Is this a valid criticism of PPL Electric's allocation proposal in this case?

A. No. As the Company has explained in prior proceedings, the dollar subsidy approach utilized by Mr. Baron is inappropriate when comparing class contribution to cost of service at two different rate levels. And, in any event, review of Mr. Kleha's revised cost of service calculations and the Company's proposed rate design demonstrate that all classes, except RTS, will produce reduced dollar subsidies under PPL Electric's proposal to move rate classes to halfway to the system average return on an indexed return basis.

Q. Please summarize the scaleback proposals of other parties.

A. The OCA supports either a straight scaleback or a rerun of the cost of service study adopted by the Commission to apply the criteria of moving rate classes halfway to cost of service on an indexed basis.

OSBA proposes additional first dollar rate relief to the GS-1 class, followed by what Mr. Knecht describes as a "differential scaleback" that calculates the difference between PPL Electric's proposed percentage increase in distribution revenues and the allowed percentage increase in distribution revenues, and reduces all other rate classes by that percentage differential. Thus, for example, if the full proposed percentage increase in distribution revenues is 13.1%, and the allowed percentage increase in distribution revenues is 11.0%, proposed rates for each rate class would be reduced to produce 2.1% less in revenues. DOD proposes to rerun the cost of service study at final rates, and then follow the basic DOD rate design proposal to reduce all classes with an indexed return over 1.25 to 1.25. Any rate class with an indexed return between 1.0 and 1.25 at present rates would be brought to an index of 1.0, provided the resulting rate increase did not exceed the system average increase. The resulting revenue deficiency to recover the allowed increase would be spread to all remaining rate classes, subject to a maximum class increase of 26%, assuming Commission adoption of the Remand Settlement.

PPLICA's proposal would provide first dollar rate relief to rate schedules IS-T and ISA, to, as Mr. Baron describes it, bring those two classes "to a rate of

return commensurate with Rate Schedule LP-5." Thereafter, PPLICA would allocate any remaining reduction from the proposed distribution increase among all rate classes on the basis of each class's percentage of total rate base.

Q. Please respond to the proposals of OCA and DOD that would involve rerunning the class cost of service study.

A. PPL Electric does not support any proposal that would involve rerunning the cost of service study to establish final rates in this proceeding. As Mr. Kleha can explain in greater detail, cost of service studies are not mathematically precise analyses, and it would give far too much emphasis to the cost of service study results to rerun the study to set final rates. Additionally, I am concerned that this potentially will add unneeded complexity and disputes to the compliance filing process. My concern is that parties might question cost adjustments and allocations in the "compliance" cost of service study, resulting in delays in implementation of new rates.

Q. Do you agree with the first dollar rate relief proposals of OSBA and PPLICA?

A. No, I do not. I believe that the Company's rate design proposal, combined with its scaleback proposal and its proposal to move generally to cost of service by the next rate case, provides adequate relief to the GS-1 and IS-T rate schedules. Rate Schedule ISA is a contract rate applicable to a single customer. Consistent with the terms of that contract, the Company is not proposing any changes to the rate schedule in this proceeding.

Q. Do you support the OSBA's differential scaleback mechanism?

A. No. The principal problem with the differential scaleback mechanism is that it gives additional rate decreases to classes that are already receiving rate decreases under the Company's proposal. This can be seen in Mr. Knecht's Exhibit IEC-2, Schedule B. Additionally, under the mechanics of the proposal, residential customers will rapidly pay a greater percentage of the increase as the total increase is reduced. This again can be seen in Mr. Knecht's Exhibit IEC-2, Schedule B. For hypothetical purposes, Mr. Knecht has assumed that PPL Electric's $83.036 million rate increase is reduced by $13.586 million, to $69.450 million. However, at that revenue increase level, RS and RTS customers combined will pay $69.778 million in increased revenues.

Q. Do you have the same concerns with DOD's and PPLICA's proposals?

A. Yes I do. DOD's Exhibit KLK-7 clearly demonstrates that at a $54.289 million increase, the RS and RTS classes would receive a $79.395 million increase. I do not believe this reasonably comports with gradualism principles.

PPLICA has not provided a calculated example of how its scaleback would operate. However, Mr. Baron's testimony indicates that he proposes to reduce his recommended class rate increases by each rate schedule's ratio of rate base to total rate base. Because Mr. Baron's recommended increase at the full rate allowance begins with residential customers paying more than the total increase, and because it appears that Mr. Baron's mechanism will give greater

rate reductions to classes that are allocated a rate reduction at the full claimed revenue allowance, it appears virtually certain that the residential share of the final rate allowance would be meaningfully above the overall rate increase under PPLICA's scaleback mechanism.

Q. DOD witness Kincel indicates that under his scaleback mechanism, residential customers would be allocated "most of the reduction in revenue requirement." Please comment.

A. Mr. Kincel's description is technically correct, but extremely misleading. As can be seen from his Exhibit KLK-5, Mr. Kincel proposes that Rate Schedule RS-residential customers pay $97.116 million out of an $83.521 million increase, or $13.595 million more than the total increase ($97.116 million minus $83.521 million). However, if the allowed increase is $54.249 million, Rate Schedule RS customers will pay $78.350 million, or $24.061 million more than the overall increase ($78.350 million minus $54.249 million). Such a result clearly is not appropriate.

Issues Raised at Public Input Hearings

Q. During the public input hearings in this case, a number of witnesses testified that the requested increase, if granted, will make it more difficult for low-income customers to pay their bills. Do you have a response to this concern?

A. Yes. PPL Electric is very concerned about the ability of its low-income customers to pay their electric bills. For this reason, the Company offers a

variety of universal service programs for these customers and is proposing in this case to substantially increase its funding these programs.

Q. What types of universal service programs does PPL Electric offer to its low-income customers?

A. As described in more detail in Timothy R. Dahl's Direct Testimony (Statement No. 8), the Company offers the following programs: OnTrack, WRAP, Operation HELP and CARES. In general terms, OnTrack offers reduced payment plans and arrearage forgiveness; WRAP provides free weatherization measures and energy conservation education; Operation HELP pays for any type of home heating bill; and CARES is an evaluation and referral service for customers with temporary hardships. PPL Electric also promotes the availability of LIHEAP, which provides energy assistance grants to low-income households (i.e., at or below 150 percent of the federal poverty level).

Q. What increases in funding for these programs is PPL Electric proposing in this case?

A. As described in more detail by Mr. Dahl, PPL Electric proposes to increase annual funding for OnTrack and WRAP by $5,800,000 and $1,000,000, respectively, from the levels approved by the Commission in the Company's most recent distribution rate case at Docket No. R-00049255. The Company also proposes to increase its annual corporate contribution to Operation HELP by 43 percent – from $700,000 to $1,000,000. Donations from customers and employees may increase slightly because of annual solicitation efforts. Funding

for CARES will increase slightly to reflect changes in wages for PPL Electric personnel who support the program. The following table shows the proposed funding for the Company's universal service programs in 2008.

Program	2005	2008	% Increase
OnTrack	$13,200,000	$19,000,000	43.9%
WRAP	6,250,000	7,250,000	16.0%
Operation HELP	912,000	1,425,000	57.3%
CARES	80,000	82,000	2.5%
Total	$20,442,000	$27,757,000	35.8%

Q. During the public input hearings, several witnesses discussed ownership and operation of different generating facilities, including nuclear plants and hydroelectric plants. Do you have a response to this testimony?

A. Yes. This case involves only the request by PPL Electric to increase its distribution rates and does not address any generation-related issues. Moreover, since its corporate restructuring in 2000, PPL Electric has not owned or operated any generating stations. For these reasons, testimony regarding generation issues, in my opinion, is beyond the scope of this proceeding.

Q. During the public input hearings, several witnesses asserted that PPL Electric realized a profit of approximately $860 million in 2006. Do you have a response?

A. Yes. The 2006 profit data cited by several witnesses in the public input hearings does not refer to profit earned by PPL Electric. Rather, that data refers to the 2006 profit reported by PPL Electric's corporate parent, PPL Corporation (i.e., $865 million). PPL Electric and PPL Corporation are separate corporate entities

that maintain separate books of account. This proceeding involves only the request by PPL Electric to increase its distribution rates. For these reasons, the financial performance of PPL Corporation is beyond the scope of this proceeding.

Q. During the public input hearings, several witnesses asserted that PPL Electric has not justified its requested rate increase. What is your response?

A. I disagree. The Company's initial filing in this proceeding contains responses to all of the Commissions' regulations regarding information to be provided with a request for an increase in base rates, twelve statements of direct testimony from PPL Electric witnesses and eighteen exhibits supporting that testimony. In addition, the Company has responded to literally hundreds of interrogatories. It submitted rebuttal testimony on July 23, 2007. In my opinion, these materials fully support PPL Electric's request for an increase of $83.6 million in its annual distribution revenues, as modified in its rebuttal testimony. Allocation of the proposed increase also is fully supported by the data submitted by PPL Electric in this proceeding. As the Company has explained, a significant portion of the increase has been allocated to residential customers consistent with the Commonwealth Court's Opinion in the Lloyd case.

Q. During public input hearings, several witnesses contended that PPL Electric's compensation to its executives is excessive. Do you agree?

A. No, I do not. Compensation for all PPL Electric employees, including its executive management, is calibrated to market compensation for comparable

positions at similar companies. The compensation to PPL Electric's executives is in line with that market data. Compensation to executive management of PPL Electric's parent, PPL Corporation, also is calibrated with market data. Moreover, only a portion of PPL Corporation's costs, including executive compensation, are allocated to PPL Electric and reflected in this rate filing. Finally, concerns regarding the compensation package awarded to PPL Corporation's former chief executive officer, who retired last year, are not relevant to this proceeding because none of those costs are reflected in PPL Electric's future test year data.

Q. At the Wilkes-Barre public input hearing on June 28, 2007, Michael Basta raised several service-related concerns suggesting that, in his opinion, trees near his residence should be trimmed and squirrel guards should be installed. How has the Company responded to these concerns?

A. Shortly after Mr. Basta testified on June 28, 2007, the Company dispatched service personnel to investigate his concerns. As a result of that investigation, the Company has issued a work order to install animal guards at two terminal poles and two transformers near his property. In addition, inspection of trees near Mr. Basta's residence indicated that several of those trees should be trimmed now, although trimming along the entire line is not scheduled until next year. As a result of its investigation, the Company has issued a work order to perform the necessary tree trimming. Both projects should be completed by the middle of August. In my opinion, installation of the animal guards and trimming

of several trees near Mr. Basta's residence should satisfy his concerns regarding service-related issues.

Q. Mr. Basta also stated that he had requested, but not received, a copy of the Company's class cost of service study in this proceeding. How has the Company responded to this concern?

A. Shortly after the June 28, 2007 public input hearing, PPL Electric provided to Mr. Basta, by overnight delivery, a copy of its complete filing in this case, including cost allocation studies for the historic test year and future test year. To the best of my knowledge Mr. Basta has not requested any additional information.

Q. Mr. Basta also advocated that PPL Electric modify its tariff rates to include a power factor adjustment. How has the Company responded to Mr. Basta's suggestion?

A. In the past, the Company considered including a power factor provision in its retail tariff rates, but concluded that it was not appropriate to adopt such a provision at this time. Such a provision would likely require the installation of meters that can measure power factor on all customers taking service under Rate Schedule GS-3 and above. The inclusion of a power factor adjustment would permit certain customers within this group to benefit at the expense of others within the same group, but this redistribution of wealth would come at the cost of additional metering that would be spread across the entire group. The Company concluded that, with customers needing to adjust to many other more

significant changes in electricity markets over the next several years, this would be a poor time to institute this additional change. I would point out that no other party in this proceeding has suggested such an approach. Moreover, Mr. Basta did not provide any data or analysis to support his recommendation. Mr. Basta was notified of the technical evidentiary hearings scheduled in mid-August and was informed that he could raise this issue at that time, if he complied with the Judge's procedural schedule. Mr. Basta has not filed any written testimony on this issue.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Exhibit DAK 1-R

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Consumer Advocate, Set VII,
Dated June 1, 2007
Docket No. R-00072155

Q.13. Please provide the annual customer education and advertising costs associated with the meter data management system for 2008 and 2009.

A.13. The Company anticipates spending $4.4 million per year in 2008 and 2009 to make customers aware of the meter data management system's energy use and bill analysis capabilities and to educate them on the system's functionality. The Company further anticipates that its education programs in 2008 and 2009 will be subject to continuing Commission review.

Exhibit DAK 2-R

PPL Electric Utilities Corporation
Response to Interrogatories of the
Office of Trial Staff, Set X,
Dated April 23, 2007
Docket No. R-00072155

Q.OTS-RE-62-D. Reference the Company's Exhibits Historic 1 and Future 1, Schedule B-4, page 3, account 909 concerning informational and instructional expense.

A. Provide an explanation and detailed breakdown of what is included in the $4,400,000 claim for informational and instructional expense in the future test year ending 12/31/2007.

B. Explain why account 909 is not listed on Schedule B-4 for the twelve months ended 12/31/2006. Identify the account that these expenses were charged to in 2006, provide the 2006 amount of informational and instructional expense and provide the same breakdown as requested in Part A. above for the 2006 expenses.

C. Provide the per book amount for informational and instructional expenses in the twelve months ending 12/31/2005, 2004, 2003 and 2002 and identify the account these expenses were charged to in those years.

A.OTS-RE-62-D.

A. The following is a breakdown and explanation of the $4,400,000 claim for informational and instructional expense in the future test year ending 12/31/2007:

Purpose	Media	Amount
Energy Conservation/Efficiency	Television	$3,315,000
	Print Media	390,000
	Bill Inserts	35,000
	Website	230,000
Electrical Safety	Website	30,000
Institutional	Television	400,000
Total		$4,400,000

B. The Company charges expenses related to advertising to various functional FERC accounts. See Attachment II-D-7d of the response to Question II-D-7, of Exhibit Regs. § 53.53, Part II-Primary Statements of Rate Base and Operating Income, for more information related to advertising expenses for the Company. The advertising expenses for 2006 were primarily charged to FERC accounts 912, 913 and 916.

C. Advertising expenses, including but not limited to informational and instructional expenses, for the years 2002-2005 are as follows (in thousands):

	Amount	Account
2002	$291	908, 912
2003	2,500	908, 912, 913
2004	2,176	912, 921
2005	264	912, 916, 921

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00072155

PPL Electric Utilities Corporation

Statement No. 6-R

Rebuttal Testimony of Joseph M. Kleha

Rebuttal Testimony of Joseph M. Kleha

Q. Please state your name and business address.

A. My name is Joseph M. Kleha. My business address is PPL Services Corporation, Two North Ninth Street, Allentown, Pennsylvania, 18101.

Q. Did you previously submit direct testimony in this proceeding on behalf of PPL Electric Utilities Corporation?

A. Yes. I submitted my direct testimony, Statement No. 6, on March 29, 2007.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the assertions of witnesses on behalf of the various intervenors on the following topics:

(1) the appropriate cost allocation methodology to be used in this proceeding, including alternatives to PPL Electric's preferred maximum non-coincident peak ("NCP") demand method for allocating demand-related costs (responding to Mr. Galligan);

(2) the use of the minimum size system study to determine the applicable customer cost component of the secondary distribution system (responding to Mr. Galligan);

(3) a reduction in cash working capital due to a change in net lag days (responding to Ms. Backer and Mr. Morgan); and

(4) the calculation of future test year capital stock tax expense (responding to Ms. Markovich and Mr. Morgan).

I would note that, along with this rebuttal testimony, I am submitting Exhibit JMK 2A-Revised.

Q. Please describe Exhibit JMK 2A-Revised.

A. Exhibit JMK 2A-Revised, like Exhibit JMK 2A, presents fully distributed Pennsylvania jurisdictional costs of providing distribution service to the various rate classes, at both present and proposed rates, for the 12 months ending December 31, 2007. The present rate revenue shown in each exhibit reflects the new rates, which were approved by the Commission in its order, entered on July 25, 2007, approving the Joint Petition for Settlement of the Company's 2004 base rate case, that will become effective on August 1, 2007. Exhibit JMK 2A-Revised is further adjusted to reflect the Company's final accounting claims and proposed revenue allocations set forth in Exhibit Future 1-Revised.

I. Cost Allocation Principles and Demand Allocation Methodology

Q. Mr. Kleha, do you have any general comments regarding the cost allocation proposals made in this proceeding?

A. Yes. First, when considering the appropriateness of a utility's proposed cost allocation methodology, cost allocation must be recognized for what it is – an art, not an exact science. Although, there is no single, absolutely correct method, there are certain fundamental principles, i.e., cost causation and consistency, that should be followed. Historically, the Commission has recognized that a cost allocation study serves as a guide, and that it is just one of several important factors to be considered, when designing a utility's rates. However, the proper

application of the fundamental principles of cost causation and consistency when preparing a cost allocation study has become somewhat more important in light of the *Lloyd* decision.

Second, the only party in this proceeding who criticizes PPL Electric's cost allocation study is Mr. Galligan, on behalf of the Office of Consumer Advocate. Mr. Galligan proposes changes which, if adopted, would reduce the level of costs assigned to the residential class. The Company, however, seeks to take a more moderate middle-of-the-road position regarding the allocation of costs to the various customer classes and, as such, does not favor one customer class over another when assigning costs. Of particular note is the fact that the Office of Trial Staff, the only other party not associated with a particular customer class, has not challenged or criticized the Company's cost allocation study. The Office of Small Business Advocate, the Department of Defense and the PP&L Industrial Customer Alliance, which represent commercial and industrial customers, all support PPL Electric's cost allocation study.

Third, consistency is an important factor in the preparation of a cost allocation study. There are obviously many different theoretical methods of cost allocation, but PPL Electric has used the same reasonable approach for many years, and that approach consistently has been accepted by this Commission in prior PPL Electric base rate proceedings. In my opinion, changing fundamental allocation methods, without a compelling reason, is not appropriate.

Fourth, a significant change in methodology in this case would be particularly inappropriate. PPL Electric's current rate structure continues to be a

product of the rate unbundling process which occurred in its electric restructuring proceeding. The unbundling of rates in that proceeding was based on the Commission-accepted cost allocation study from PPL Electric's 1995 base rate proceeding, which reflected the Company's operation as a vertically integrated electric utility. As such, PPL Electric's current rate structure continues to reflect vestiges of its prior vertical integration. Although the rate cap on PPL Electric's transmission and distribution rates ended on December 31, 2004, the cap on its generation rates extends through 2009. It would be inappropriate, in my view, to undertake a major revision to the cost allocation procedures that PPL Electric has used for many years under these circumstances.

Finally, the Company has committed to move all rate classes toward the system average rate of return and cost-based rates over three base rate cases, counting this current proceeding as the second case. In my opinion, this movement should be measured over these cases on a consistent basis. As such, the cost allocation methodology employed, and the metric used to measure each rate class' progress toward the system average rate of return and cost-based rates, as well as each rate class' ongoing position relative to the system average rate of return, should be same along each step of the process and thereafter. The methodology used by PPL Electric in this proceeding, and in prior base rate proceedings, for the allocation of its distribution system capital and operating costs clearly provides the consistency required to track the movement of various rate classes to cost-based rates over time.

Q. Mr. Kleha, the relative rates of return in the Company's updated cost allocation study continue to show a substantial variance from the cost of providing service for some rate classes at present rates. Is this an indication that the Company's study is incorrect or invalid?

A. No, it is not. The relatively large variance in the class rates of return is a result of the unbundling of the Company's rates during electric restructuring. Prior to unbundling, the Company's vertically integrated rates produced class rates of return that showed only minimal variance from the full cost of providing service. For example, at Docket No. R-822169, the rate of return provided by Rate Schedule RS at the Company's proposed rates was 92.5% of the system average rate of return, and Rate Schedule GS-1 was providing 110.1% of the system average rate of return. At Docket No. R-842651, the rate of return provided by Rate Schedule RS at the Company's proposed rates was 100.3% of the system average rate of return, and Rate Schedule GS-1 was providing 102.9% of the system average rate of return. Ten years later, at Docket No. R-00943271, the Company's compliance cost allocation study showed that the rate of return being provided by Rate Schedule RS was 80.1% of the system average rate of return, and Rate Schedule GS-1 was providing 164.6% of the system average rate of return.

These positions changed substantially in the Company's 2004 base rate case, which was filed on a distribution-only basis. The results of the Company's 2004 test year cost allocation study showed that, at then present rates, the RS rate class was providing 40.86% of the system average rate of return, and the

GS-1 rate class was providing 237.61% of the system average rate of return. Clearly, as a result of rate unbundling, there was a significant shift away from the system average rate of return. The Company has used the same basic cost allocation methodology for many years. The variance in the rates of return in this proceeding is the result of rate unbundling, and provides no basis for challenging the Company's cost allocation methodology.

As explained in Mr. Krall's testimony, the Company is addressing this variance in class rates of return by proposing revenue allocations that will move rate classes to the cost of providing service over the course of three rate cases, with the Remand Settlement in the 2004 base rate case being the first case, and this case being the second of those three cases. After the Company's next base rate case, the variance in class rates of return will be substantially, if not completely, eliminated.

II. NCP Demand Allocation Methodology

Q. Please describe PPL Electric's allocation of the costs associated with its demand-related distribution facilities.

A. The fundamental purpose of a cost allocation study is to aid in the design of rates by identifying all of the capital costs (plant and equipment) and operating costs (O&M expenses, depreciation, and taxes) incurred by a utility to provide service to its customers, and then assigning and/or allocating these costs to individual rate classes on the basis of how those rate classes cause these costs to be incurred. To ensure a fair and consistent result, PPL Electric's allocation of the

costs associated with its distribution-related facilities adheres to the guidelines set forth in the NARUC Electric Utility Cost Allocation Manual (January 1992).

The NARUC Manual (p. 90) states that "when the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand-and customer-related costs." The NARUC Manual (pp. 96-97) also states that an electric utility's distribution facilities are, from a design and operational basis, sized to meet the maximum load (demand) requirements of customers. Consequently, PPL Electric believes that the use of the maximum NCP demand allocation methodology is the most appropriate method for allocating the costs of its demand-related distribution facilities. It should be noted that PPL Electric historically has used, and this Commission has accepted, the use of the maximum NCP demand method to allocate the costs associated with the demand-related distribution facilities reflected in the Company's previous base rate cases. PPL Electric properly classifies the costs associated with the components of its distribution facilities, i.e., poles, towers and fixtures; overhead and underground conductors and devices; underground conduit; transformers; and services, as either demand-related, customer-related, or a combination of both through a minimum size system study, which is provided in Exhibit JMK 3. After the components of its distribution facilities are classified, the demand-related costs are allocated to each customer class based on that class's maximum NCP demand; customer-related costs are allocated based on the number of customers in the customer class. Accordingly, PPL Electric firmly

believes that its cost allocation methodology, as set forth in Exhibit JMK 2A, and Exhibit JMK 2A-Revised, provides an accurate and consistent measure of rate class cost responsibility for its distribution system.

It also should be noted that PPL Electric plans and designs its distribution system to operate safely and efficiently. As such, this system is planned and designed to maintain a proper balance between service reliability and the cost of providing that service, and to avoid large-scale, long-term or frequent interruptions because of the adverse effects on and hazards to the public. This principled planning and design approach for its distribution system provides the rationale for PPL Electric's position regarding the allocation of costs to the various customer classes.

Q. Do you agree with Mr. Galligan's proposed use of a peak and average (energy) allocation methodology to allocate the costs associated with distribution-related facilities?

A. No, I do not. The use of the peak and average (energy) allocation method proposed by Mr. Galligan would allocate the costs associated with PPL Electric's distribution-related facilities 50% on the basis of the kW load (demand) imposed on the distribution system by customers, and 50% on the basis of energy (kWh) consumed by those customers. The allocation of fixed costs associated with distribution-related facilities in this manner is inappropriate for the following three reasons.

First, Mr. Galligan proposes to allocate all distribution-related costs, other than meters and services, based on demand and energy allocators. He proposes no customer-related component for these costs at all. From Mr. Galligan's perspective, the design of the Company's distribution system is completely unrelated to the number of customers on its system. There is simply no rational basis for this conclusion.

Second, the NARUC Manual (p. 89) succinctly states, regarding distribution-related capital and operating costs, that: "Because there is no energy component of distribution-related costs, we need consider only the demand and customer components." (Emphasis added). The NARUC Manual also states (p. 90) that: ". . . each distribution account must be analyzed before it can be assigned to the appropriate functional category. Also, these accounts must be classified as demand-related, customer-related, or both."[1] The NARUC Manual does not state, or even suggest, that any portion of an electric utility's distribution-related facilities should be assigned and/or allocated on the basis of energy consumed by customers.

Third, the size of distribution facilities does not vary based on the amount of energy that is consumed by customers, also referred to as average demand by those who advocate the use of the peak and average (energy) method. Rather, distribution facilities are sized to meet the peak load (peak demand)

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[1] The Cost of Service Procedures for Public Power Systems Cost Allocation Manual (Section IX-8) states that: "As previously indicated, distribution plant is a fixed investment in facilities which do not vary with the consumption of energy and which are closest to the point of use. Therefore, distribution plant is classified as demand and customer-related cost."

requirements of customers, and those facilities increase in size only when the peak load requirements imposed on those facilities outgrow the capability of the facilities.

As a result, the peak and average (energy) method does not, in my opinion, properly recognize cost causation when it is used to allocate the costs associated with an electric utility's distribution-related facilities on the basis of energy consumed by customers.

Q. Mr. Galligan asserts that PPL Electric's distribution system would not exist but for average customer demands and, therefore, average demands should be used to allocate costs. Do you agree?

A. No, I do not. Although revenues may define the viability of an individual project, and may determine whether customer contributions or minimum bill requirements are invoked, energy sales do not define the design of the distribution system to be installed.

III. Use of a Minimum Size System Study

Q. Have you reviewed Mr. Galligan's criticism of PPL Electric's use of a minimum size system study to determine those costs to be classified as customer-related?

A. Yes, I have. Mr. Galligan criticizes PPL Electric because its minimum size distribution system study is based on the smallest size equipment currently being installed on its system, and because the smallest size of certain individual components of that equipment have changed over time. He also criticizes PPL

Electric's method, stating that it results in a greater attribution of costs to the customer-related classification than would result from using a different method. Mr. Galligan raises the "zero intercept" method as an alternative for classifying costs as customer-related, but has not offered the results of using that method. He offers only his peak and average (energy) demand allocation method, which provides no basis for the classification of distribution-related costs, to support his position. In addition, Mr. Galligan criticizes PPL Electric for not allocating a portion of its distribution-related facilities on the basis of the maximum coincident peak load imposed on its system.

Q. Do you agree with these criticisms?

A. No, I do not. PPL Electric has followed the NARUC Cost Allocation Manual (p. 90-91) which defines a minimum size distribution system as that based on the smallest size equipment currently being installed by the utility. As such, it is clearly recognized that the size of individual components of the minimum size system can change as the load imposed by customers on an electric utility's distribution-related facilities increases over time. Moreover, the NARUC Manual (p. 97) clearly states that customer-class non-coincident peak demands (NCPs) are the load characteristics that normally are used to allocate the demand component of distribution-related facilities. Therefore, Mr. Galligan's criticisms are unsupported and clearly inconsistent with the NARUC Cost Allocation Manual.

Q. Mr. Galligan asserts that the minimum size system method is arbitrary because of changes in the minimum size of installed equipment, e.g., transformers, used in the Company's minimum size system study in prior cases. Do you have any comments?

A. As I previously discussed, the NARUC Manual recommends the use of the smallest size equipment currently being installed on an electric utility's distribution system. Presently, a 10 kVh transformer is the smallest size transformer currently being installed on the Company's distribution system. Accordingly, the Company's adjustment of the components of its minimum size system study to reflect up-to-date data can not be considered to be arbitrary.

Q. Mr. Galligan seems to suggest that the zero intercept method is better than the minimum size system method. Is this suggestion practical?

A. No. The Company has investigated the use of the zero intercept method and found this method impractical, given the available data in its accounting records. As most cost analysts recognize, this method has inherent problems, namely the lack of necessary data. Even if the necessary data were available, the zero intercept method is complex and inherently arbitrary. PPL Electric's last review of this method produced negative zero intercept cost results for wood poles, copper conductors and aluminum conductors. Therefore, the zero intercept method obviously is not an accurate or reasonable approach for PPL Electric.

Q. Have you reviewed Mr. Galligan's criticism that the Company's minimum size equipment has some load-carrying capability?

A. Yes, I have.

Q. Do you agree with his proposal in that regard?

A. No. Mr. Galligan proposes to adjust the Company's allocators because the equipment used in its minimum size system study has some load-carrying capability. This proposal is flawed for several reasons.

First, a minimum size distribution system, by definition, must have some load-carrying capability. The fact that the Company's minimum system has some load carrying capability provides no basis for rejecting it.

Second, demand is a function of the load imposed on an electric utility's system by its customers and this demand, and the allocators derived from it, are unaffected by a "hypothetical" minimum size system study.

Third, because of the criticism received from several parties in the Company's most recent base rate proceeding at Docket No. R-00049255 regarding the load-carrying capability of the equipment used in its minimum size system study, PPL Electric undertook an analysis to identify the customer-related "minimum or no load" portion of that equipment. As more fully described in Statement No. 6, the results of this analysis were applied to overhead and underground transformers, overhead and underground conductors, and services. Accordingly, only the "minimum or no load" portion of these facilities has been

classified as customer-related; the remaining portion of these facilities has been classified as demand-related.

Finally, primary voltage level distribution facilities are installed to operate consistent with the appropriate application of normal and emergency ratings for equipment. The maximum acceptable loading (demand) on a PPL Electric facility is determined by the sustained loading (demand) capability of the most limiting piece of equipment comprising that facility. PPL Electric allocates its primary voltage-related distribution system costs solely on the basis of the demand imposed on those facilities by the customer classes using those facilities to take retail service, even though the primary voltage system may have a customer-related cost component. However, any potential overstatement of the demand-related portion of the primary voltage system would offset any potential overstatement of the customer-related cost component associated with the secondary voltage-related distribution system.

Q. Do you have any further comments regarding the minimum size system issue?

A. Yes. Secondary voltage level distribution facilities, e.g., transformers and conductors, are sized to meet the maximum load (demand) requirements imposed by the customers (not on the basis of energy consumed by those customers) who are served from those facilities, whether for 1 hour or 24 hours per day. As a result, the number of customers served by those facilities does affect the size (and number) of those facilities. The National Electric Safety Code requires that electric utility facilities be placed in the space at the top end of a

pole. As a result, electric utility poles are sized (height) on the basis of the type and number of electric facilities, i.e., conductors, transformers, reliability-related devices (oil circuit reclosers, lightning arrestors, circuit breakers, etc.) and other non-electric attachments, e.g., cable TV, telecommunications, and public safety devices placed on the pole, not on the basis of energy consumed (kilowatt-hours) by customers. The Company's minimum size system study is designed to identify the applicable customer and demand-related costs components to determine the current cost of the "minimum size" system necessary to provide reliable distribution service to its customers.

Q. Have you reviewed Mr. Galligan's testimony regarding his determination of a distribution-related customer charge for the RS customer class?

A. Yes, I have. In his testimony, Mr. Galligan criticizes the calculation of PPL Electric's proposed customer charge for the RS customer class because, in his opinion, it is overstated due to an over-allocation of costs. He calculates a customer charge of $6.76, which is set forth on Schedule RAG-4 to his testimony.

Q. Do you agree with Mr. Galligan's proposed calculation of a customer charge for the RS customer class?

A. No, I do not. My review indicates that, because Mr. Galligan relies on his proposed peak and average (energy) allocation method to obtain the customer-related cost components of PPL Electric's distribution facilities, his calculation of

a customer charge for the customer class RS is fundamentally flawed. The peak and average (energy) method does not provide a basis for the classification of costs associated with the components of PPL Electric's distribution facilities as either demand-related, customer-related, or a combination of both. In addition, as I previously discussed, this methodology does not provide an appropriate basis for the allocation of distribution-related costs. Moreover, the peak and average (energy) method always will, by its very construct, understate the level of customer-related costs applicable to the Company's distribution facilities.

Q. How did PPL Electric calculate its proposed customer charge for the RS customer class?

A. PPL Electric used its minimum size system study to determine all of the customer-related costs applicable to its distribution system. These "minimum size" system customer-related costs, including associated operating costs, as well as those other customer-related capital and operating costs that are directly related to customers, e.g., meters, meter reading expenses, billing and collection expenses, etc., are identified, and the associated revenue requirement is calculated to determine the level of the customer charge to be applied to monthly billings for the RS customer class. Exhibit JMK 4 provides the development of total customer-related costs applicable to PPL Electric's distribution system from which the costs associated with its proposed customer charge are derived. The Company has limited the costs included in the calculation of its customer charge only to the revenue requirement associated with those directly assignable

customer-related costs. These customer-related costs include, but are not limited to, the following categories of cost: meters and services net plant (including applicable O&M expenses); meter reading, billing and collection, and customer call center expenses (including applicable operating costs, such as personnel wages and benefits, administrative and other support-related costs, customer recordkeeping, customer service and informational communications expenses); depreciation expense on applicable plant and equipment; taxes–*income and other; return on the applicable distribution and general plant* (portions of buildings that are used for customer-related activities, i.e., call centers, office furniture and equipment, etc.), and other related rate base items (working capital, accumulated deferred taxes, etc.); and revenue credits derived from late payment charges. As shown on Exhibit JMK 4, PPL Electric could have justified a customer charge of at least $13.49. However, the Company conservatively has chosen to increase the customer charge for the RS customer class only to $10.00.

IV. Cash Working Capital

Q. Have you reviewed Ms. Backer's and Mr. Morgan's testimony regarding the Company's claim for cash working capital?

A. Yes, I have. Both Ms. Backer and Mr. Morgan propose reductions to PPL Electric's claim for working capital required for O&M expenses, as shown on page 2 of Schedule C-4, Exhibit Future 1, by adjusting the payment lag days of various categories of expense that are set forth in the Company's lead/lag study

provided in its response to Question II-B-4 of Exhibit Regs., §53.53, Part II–Primary Statements of Rate Base and Operating Income.

Q. Please describe PPL Electric's lead/lag study.

A. The Company's lead/lag study measures the cash inflow and outflow associated with operating revenues and expenses. That is, the lead/lag study determines the average lead and/or lag in days between the payment of various categories of O&M expense and the receipt of the revenue from customers.

In preparing its lead/lag study, PPL Electric followed the criteria set forth in Question II-B-4 of Exhibit Regs., 53.53, Part II–Primary Statements of Rate Base and Operating Income, which requires that a utility making a claim for working capital "provide a lead/lag study, completed no more than 6 months prior to the rate increase filing." Because the Company filed its proposed base rate increase on March 29, 2007, the 6-month period prior to the filing ended on, or about, September 30, 2006. As a result, PPL Electric used the 3-month period ended September 30, 2006 as the sample period for its lead/lag study. It should be noted that PPL Electric historically has used, and this Commission has accepted in the Company's prior base rate proceedings, a 3-month sample period, completed no more than 6 months prior to a rate increase filing, as a representative period for analysis of O&M expense payments and rate revenue receipts.

The sample selection process and sample size for the various categories of O&M expense, particularly the Other Operating Expense category, used in this

proceeding are consistent with the selection process and sample size used in the Company's lead/lag studies in prior proceedings. The sample of invoices, which are used to ascertain the payment lag days for other operating expenses, were selected on a random basis, with the specific criteria that a variety of payees be included in the sample, and that the sample contain transactions which have a higher percentage of dollar payment value when compared to the total dollar value of the category of expense being sampled. For example, in the Services category of expense, the sample chosen included the 10 largest transactions and every 10^{th} transaction down to a payment amount of $2,000. The Company believes that this sampling technique provided a very good indicator of the overall Services category by including approximately 70% of the total dollar value of this expense category and almost 10% of the total population of transactions. A similar methodology was used for all other categories of other operating expense. Because most expense categories contain a large number of very small dollar value transactions (less than $100), the Company's sample selection emphasizes the ratio of sample population dollar value to the total population dollar value as opposed to the ratio of the sample population transactions to the total population of transactions. Accordingly, PPL Electric believes that its analysis of the payment transactions for the 3-month period ended September 30, 2006, which is reflected in the lead/lag study submitted in this proceeding, provides a reasonable and accurate approximation of the O&M expense and rate revenue leads and/or lags for the full 12 months of the study period.

Q. Ms. Backer criticizes the Company for failing to conduct a 12-month analysis to calculate revenue and expense leads and lags. Is this a valid criticism?

A. No, it is not. First, the Company has utilized its 3-month sample period in every base rate case for the last 25 years. It has never been criticized, and it has been accepted by the Commission in each case. The same is true for the Company's gas utility. Second, it would be very costly and time consuming to conduct a full 12-month lead/lag analysis. Third, such an analysis is not required by the Commission's filing regulations and, therefore, is not required of any other utility in the Commonwealth. Fourth, there is absolutely no indication that using a 12-month period would yield any material difference in the result. Ms. Backer cites one utility, National Fuel Gas Distribution Corporation, as an example of a company that has used a 12-month analysis. Presumably, no other utility does so, or Ms. Backer would have cited it. The fact that a single gas utility uses a 12-month period does not support imposing such a requirement on PPL Electric. Moreover, it is my understanding that National Fuel Gas used a 12-month analysis period in its most recent base rate case following the installation of new computer software that allows it to automatically track its accounts payable electronically. PPL Electric does not have such a system. Finally, to demonstrate the lack of merit in Ms. Backer's argument, PPL Electric, at substantial time and cost, expanded its analysis period to six months, i.e., April 1, 2006 through September 30, 2006. The results of this expanded analysis were supplied to the parties in a supplemental response to an interrogatory form the Office of Trial Staff.

Exhibit JMK 5 provides the results of this expanded O&M expense payment lag analysis that reflects data for the 6 months ended September 30, 2006, as well as the change in the average lag days related to the payment of other operating expenses and the overall average lag in the payment of operating expense, as shown on page 2 of Schedule C-4, Exhibit Historic 1. These results, which reduce the net lag between the payment of O&M expenses and the receipt of revenue from customers from 10.7 days to 10.1 days, are incorporated into the Company's final claim for working capital related to O&M expenses shown on page 2 of Schedule C-4, Exhibit Future 1-Revised. This adjustment reduces the Company's claim for working capital related to O&M expenses by $909,000, or $516,000 on a PUC jurisdictional basis.

Q. Have you reviewed the specific adjustments proposed by Ms. Backer to the Company's calculated payment lag analysis?

A. Yes, I have. Ms. Backer proposes several adjustments to the Company's payment lag analysis. First, she proposes to exclude numerous payment transactions from the Company's invoice sample because the payment for the service rendered occurred after the last day of the sample period, which was September 30, 2006. Second, she proposes to adjust the payment transaction for services provided by Electrocon International, Inc. because the amount shown on the invoice did not reflect the same amount as the Company included in its payment lag analysis. Third, she proposes to adjust the payment lag analysis for several transactions, including the Electrocon transaction, because

the invoices cover a 12-month period. Finally, she proposes to exclude payment transactions associated with Asplundh Tree Expert Company because the vendor was experiencing billing problems during 2006.

Q. Do you agree with Ms. Backer's proposed adjustments?

A. No, I do not. At the outset, I want to state that I strongly disagree with Ms. Backer's proposal to exclude numerous invoices from the Company's payment lag analysis simply because the date of the payment was after September 30, 2006. This proposal clearly is inconsistent with the purpose of a payment lag analysis, which is to determine the time elapsed between the rendering of the service and the actual payment (cash outflow) for the service rendered. Ms. Backer's arbitrary exclusion of such transactions seriously distorts the results of the payment lag analysis.

PPL Electric's sample selection process is designed to select and analyze a representative sample of invoices reflected on the Company's accounting records during the sample period. The transaction is reviewed to ascertain the transaction's applicable service date and the corresponding payment date. The lag between the midpoint of the service period and the payment date then is calculated. All of the transactions selected for the 3-month ended September 30, 2006 sample period relate to invoices that had accounting transaction dates that fell within the sample period, which is when the transactions appeared on the accounting records of the Company. In some instances, however, the payment date obviously could, and some did, fall outside of this 3-month window. Under

Ms. Backer's proposal any transaction that has a payment date outside this 3-month window would be automatically and arbitrarily excluded from the sample. For example, if a transaction were recorded on the Company's accounting records on September 20, 2006 (within the sample period), with a service period midpoint of June 1, 2006 and a payment date of October 3, 2006, the lag associated with this transaction would be 124 days. However, Ms. Backer would exclude this transaction. If this same transaction would appear on the Company's accounting records on September 20, 2006, and have a service period midpoint of July 1, 2006 and a payment date of September 30, 2006, the lag associated with this transaction would be 91 days, and it would be included in the sample. If, however, the same transaction had a payment date of October 1, 2006, the lag would be 92 days, and this transaction would be excluded from the sample. This result clearly is arbitrary and inappropriate. It produces a distorted and non-representative sample, and, as such, it should be rejected.

Ms. Backer also proposes to adjust the transaction for service provided by Electrocon because the dollar amount on the invoice did not match the amount included the Company's payment lag analysis. Ms. Backer's proposed adjustment is inappropriate because the difference between the two amounts represents the Pennsylvania Sales and Use Tax that PPL Electric must pay. The amount reflected in the payment lag analysis includes the amount actually paid (cash outflow), including sales and use tax, and recorded on the Company's books and records.

In addition, Ms. Backer proposes to adjust the payment lag analysis because several invoices, including the Electrocon invoice, cover a 12-month period. I disagree with this proposed adjustment because Ms. Backer's approach clearly is inconsistent with the purpose of a payment lag analysis. The payment of the Electrocon invoice was made on September 25, 2006, which covered the 12-month period ended September 4, 2007. As a result of this cash outflow, the Company would not have use of these funds for a 12-month period. Ms. Backer's proposal to prorate this prepayment over one quarter, even though the Company clearly is paying well in advance of the service being rendered, inappropriately distorts the results of the Company's payment lag analysis.

Regarding the Tree Trimming category of O&M expenses, Ms. Backer proposes to exclude the payment transactions associated with Asplundh because the vendor was experiencing billing problems during 2006. I believe that this proposal is inappropriate. In its filed payment lag analysis, PPL Electric gave consideration to Asplundh's billing problems by reviewing invoices received in the 4th quarter of 2006. During that period, Asplundh, which is a major tree trimming vendor, began billing PPL Electric every week, with the midpoint of the service period being approximately 9 days prior to the invoice date. To normalize the Asplundh service period data for its payment lag analysis sample period, the Company assumed that the midpoint of the service period was a consistent 9 days prior to the sample period invoice date to obtain a normalized midpoint for the service period. PPL Electric now has sampled additional Asplundh invoices that were received during the 2nd quarter 2007 to determine whether the

Company's initial assumption produced a reasonable result. This recent sampling indicates that payment lag days for Asplundh transactions should be approximately 52 days, rather than the number of days (42) shown in the Company's initial payment lag analysis. Accordingly, the Company has incorporated this information into the payment lag analysis being provided as Exhibit JMK 5.

Q. Have you reviewed the specific adjustments proposed by Mr. Morgan to the Company's payment lag analysis?

A. Yes, I have. Mr. Morgan proposes several adjustments to the Company's payment lag analysis. First, he proposes to exclude the transactions related to Henkels & McCoy because the work period was not specified on some of its invoices. Second, he proposes to exclude the transaction to Pennsy Supply because the delivery date of the materials or supplies was not specified on the invoice. Third, he proposes to exclude one of two invoices from Signalcrafters because it was a duplicate. Fourth, he proposes to adjust the transaction date on certain credit card purchases. Finally, Mr. Morgan proposes to exclude the payment transactions of Asplundh because the vendor was experiencing billing problems in 2006.

Q. Do you agree with Mr. Morgan's proposed adjustments?

A. I agree with certain adjustments and I disagree with others. As I have indicated, Mr. Morgan proposes to exclude the transactions related to Henkels & McCoy

because the work period was not specified on some of its invoices. In its payment lag analysis, the Company used the invoice date as the service period because Henkels & McCoy's billing procedures involve aggregating numerous work requests into a single invoice, without always listing the dates that the work was performed on the invoice. Upon investigation, PPL Electric determined that Henkels & McCoy submits its invoices on a weekly basis for work performed during the prior week. As a result, the Company has adjusted the midpoint of the service period to the Wednesday of the week prior to the invoice date, and has incorporated this modification into the payment lag analysis being provided as Exhibit JMK 5.

Mr. Morgan also proposes to exclude the transaction with Pennsy Supply for materials and supplies because PPL Electric used the invoice date as the midpoint of the service period. Vendors of materials and supplies generally do not specify the delivery date on invoices for materials and supplies, because the invoice date typically coincides with the actual delivery date. As a result, the Company believes that it is reasonable, given the data available, to use the invoice date as the midpoint of the service period for this category of O&M expenses. Accordingly, Mr. Morgan's proposed exclusion of this invoice should be rejected.

In addition, Mr. Morgan proposes to exclude one of two invoices from Signalcrafters because it was a duplicate. PPL Electric agrees that the second invoice inadvertently was included in the sample and should be removed. The initial invoice was dated July 20, 2006, but the request for payment was denied,

and the invoice was resubmitted on August 15, 2006. Payment was made on September 14, 2006. This adjustment has been incorporated into the payment lag analysis being provided as Exhibit JMK 5.

Mr. Morgan also proposes to adjust the transaction date on certain credit card purchases. In its payment lag analysis, the Company used the date that appeared on the U.S. Bank file as the date of service for these transactions, which Mr. Morgan correctly points out generally is two days after the invoice. This adjustment has been incorporated into the payment lag analysis being provided as Exhibit JMK 5.

Like Ms. Backer, Mr. Morgan proposes to exclude the payment transactions associated with Asplundh because this vendor was experiencing billing problems in 2006. As discussed in detail regarding Ms. Backer's proposal on this issue, the Company has incorporated the additional information it has obtained regarding the number of payment lag days for the Asplundh transactions into the payment lag analysis being provided as Exhibit JMK 5.

V. Capital Stock Tax

Q. Have you reviewed the testimony of Ms. Markovich regarding the Company's claim for capital stock tax expense?

A. Yes, I have.

Q. Do you agree with Ms. Markovich's proposals regarding capital stock tax?

A. Not entirely. Ms. Markovich proposes to modify PPL Electric's claim for capital stock tax expense by (1) adjusting the net worth at December 31, 2007 for an error identified by the Company at present rate conditions, and (2) decreasing the capital stock tax rate for the future test year from the 2007 rate of 3.89 mills to 2.89 mills, which is the 2008 capital stock tax rate. Ms. Markovich also proposes to exclude the Company's claim for an incremental increase in its future test year capital stock tax expense, at proposed rate conditions, which is associated with the net income produced by its proposed revenue increase.

Q. Is Ms. Markovich's proposed adjustment to the Company's net worth at December 31, 2007, as shown on page 2 of Schedule D-12 correct?

A. Yes, it is. In its response to Question OTS-RE-92-D of Interrogatories of the Office of Trial Staff, Set XIII, dated April 26, 2007, the Company indicated that there was an error in the value of its net worth at December 31, 2007, under present rate conditions, and that the correct value was $1,332,576,000. Ms. Markovich appropriately used this corrected value in her proposed adjustment. However, in its response to Question OTS-RE-127-D of the same set of interrogatories, the Company indicated that the net income amount for 2007 also was in error, and that the correct net income amount was $50,350,000. The Company has reflected both of these corrections on Schedule D-12 of Exhibit Future 1-Revised.

Q. Ms. Markovich proposes to adjust PPL Electric's future test year capital stock tax liability by using a rate of 2.89 mills, rather than the current 2007 rate of 3.89 mills. Is this appropriate?

A. No. Reaching into the 12-month period subsequent to the end of the future test year to use the 2008 capital stock tax rate to adjust the Company's future test year capital stock tax liability is appropriate only if the adjustment of the Company's future test year capital stock tax liability at both present and proposed rate conditions is done consistently.

Q. Please explain.

A. Ms. Markovich proposes to adjust the Company's future test year capital stock tax liability, at present rate conditions, by using the capital stock tax rate that will become effective on January 1, 2008. However, she also proposes to eliminate the Company's claim for additional capital stock tax liability, which is produced by the incremental increase in net income associated with the proposed revenue increase in this proceeding, because this revenue increase will not become effective until 2008, and because she believes that capital stock tax is not directly proportional to the increased revenue. Ms. Markovich's approach clearly is inconsistent and should be rejected.

Moreover, Ms. Markovich's proposal is inappropriate and contrary to sound ratemaking principles. One of those ratemaking principles requires that a utility's revenue requirement be established on the basis of normalized test year operations. As such, the utility's test year results, at proposed rate conditions,

should reflect the full effect on revenues and expenses of the requested increase in revenues. Because any revenue increase will incrementally increase a utility's net income, the amount of the utility's tax liability, including its capital stock tax liability, must reflect the full effect of that revenue increase. PPL Electric's net income will incrementally increase due to its requested revenue increase and, thereby, incrementally increase its capital stock tax liability. As a result, PPL Electric's calculation of the full effect of the requested revenue increase must reflect the incremental increase in its capital stock tax liability, just as it reflects the increase in its gross receipts tax liability and its state and federal income tax liabilities. Accordingly, this Commission's calculation of its allowed revenue increase in this proceeding must reflect the full effect of the incremental increase in PPL Electric's capital stock tax liability, as well as the incremental increase in all other taxes.

Therefore, in order to maintain consistency of the calculation of the future test year capital stock tax liability, the 2008 capital stock tax rate of 2.89 mills can be used to calculate the Company's future test year capital stock tax liability at present rates, only if the incremental increase in capital stock tax liability, which is produced by the proposed revenue increase that will become effective on January 1, 2008, also is included in the calculation of the capital stock tax liability, as shown on page 6 of Schedule D-13, Exhibit Future 1-Revised.

Alternatively, the difference between the future test year capital stock tax rate of 3.89 mills and the 2008 capital stock tax rate of 2.89 mills will be included

in the Company's State Tax Adjustment Surcharge ("STAS") filing that will be made on December 21, 2007 to become effective on January 1, 2008.

Q. Have you reviewed Mr. Morgan's testimony regarding the Company's claim for capital stock tax expense?

A. Yes, I have. Mr. Morgan, like Ms. Markovich, proposes to modify PPL Electric's claim for capital stock tax expense by (1) decreasing the capital stock tax rate for 2007 from 3.89 mills to 2.89 mills, and (2) excluding the Company's claim for an incremental increase in its future test year capital stock tax expense associated with the net income produced by the proposed revenue increase in this proceeding.

Q. Do you agree with Mr. Morgan's proposals regarding the calculation of the Company's future test year capital stock tax expense?

A. No, I do not. For all of the reasons I previously discussed with regard to Ms. Markovich's proposals, Mr. Morgan's proposals should be rejected.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00072155

PPL Electric Utilities Corporation

Exhibit JMK 4

Residential Customer Charge

PPL ELECTRIC UTILITIES CORPORATION
CUSTOMER CHARGE CALCULATION FOR CUSTOMER CLASS RS
2007 REVENUE REQUIREMENTS
($1,000)

Customer Class: RS		Total RS COS			RS Customer-Related							
		Customer-Related	Demand-Related	Total	Meters	Services	Meter Reading	Other Cust Exps	Total Direct (1)	Allocated Costs (2)	Total Customer Charge	Excluded Expenses
Rate Base:												
Plant in Service		1,701,140	838,191	2,539,331	176,387	444,156			620,543	1,080,597	1,701,140	
Depreciation Reserve		665,996	301,413	967,409	57,978	225,606			283,584	382,412	665,996	
Net Plant		1,035,144	536,778	1,571,922	118,409	218,550			336,959	698,185	1,035,144	
Subtractive Adjustments		179,434	85,250	264,684	20,525	37,884			58,409	121,025	179,434	
Additive Adjustments		20,549	9,456	30,005	2,351	4,339			6,689	13,860	20,549	
Total Rate Base		876,259	460,984	1,337,243	100,234	185,005			285,239	591,020	876,259	
Operating Expenses:												
Misc Distrib Expenses		6,260	3,275	9,535						6,260	6,260	
Social Programs (Separate Rider)		25,481		25,481								25,481
PUC Annual Assessment		2,395	717	3,112						2,395	2,395	
Wages & Benefits		15,088	4,383	19,471	1,634	261	434	5,595	7,924	7,164	15,088	
Other A&G		53,424	15,519	68,943	4,860	2,408	1,833	37,595	46,697	6,727	53,424	
Other O&M Expenses		85,828	28,729	114,557	7,808	3,869	2,945	60,398	75,020	10,808	85,828	
Proforma Adjustments		3,823	47	3,870					0	0	0	3,823
Depreciation Expense		53,408	21,082	74,490	10,821	10,105			20,926	32,482	53,408	
Taxes Other Than Income		5,135	1,936	7,071	587	1,084			1,672	3,463	5,135	
Return	7.36%	64,493	33,928	98,421	7,377	13,616			20,994	43,499	64,493	
Income Taxes	41.49%	30,690	16,145	46,835	3,511	6,480			9,990	20,700	30,690	
Tax Adjustment		(204)	(107)	(311)					0	(204)	(204)	
Gross Revenue Requirements		345,821	125,655	471,475	36,598	37,823	5,212	103,588	183,222	133,295	316,517	29,304
Annualization Adjustment		2,026	736	2,762	214	222	31	607	1,073	953	2,026	
Late Payment Charges		4,273	1,552	5,825	452	467	64	1,280	2,264	2,009	4,273	
Other Operating Revenues		13,902	7,273	21,175	1,471	1,520	210	4,164	7,366	6,536	13,902	
Total Revenues		20,200	9,562	29,762	2,138	2,209	304	6,051	10,703	9,498	20,200	0
Net Revenue Requirements		325,620	116,093	441,713	34,461	35,614	4,908	97,537	172,519	123,797	296,316	29,304
GRT Base		331,919	118,382	450,300	35,127	36,303	5,003	99,424	175,856	126,758	302,615	29,304
GRT Gross-up		352,730	125,804	478,534	37,330	38,579	5,316	105,658	186,882	134,706	321,588	31,141
GRT	5.90%	20,811	7,422	28,233	2,202	2,276	314	6,234	11,026	7,948	18,974	1,837
Total Revenue Requirements		366,632	133,077	499,709	38,801	40,099	5,526	109,822	194,248	141,243	335,490	31,141
Customer Charge		$25.47							$13.49	$9.81	$23.30	$2.16
Number EOY Customers		1,199,704										
Annual Customer Billings		14,396,448										

Notes:

[1] Includes meters, services and directly assignable customer-related operating costs.

[2] Includes all other (overhead lines, underground lines, line transformers and general and intangible) allocated customer-related capital and operating costs.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00072155

PPL Electric Utilities Corporation

Exhibit JMK 5

Payment Lag Analysis

PPL ELECTRIC UTILITIES CORPORATION

Working Capital Required for Operation and Maintenance Expenses
As of December 31, 2006
(Thousands of Dollars)

Line No.	Description	Amount	Avg. Days	Weighted Amount
	Average Lag in Receipt of Operating Revenue			
1	Revenue from 15-day due date customers	$339,887	34 (a)	$11,556,158
2	Revenue from 20-day due date customers	460,220	57 (a)	26,232,540
3	Revenue from 30-day due date customers	224,499	38 (a)	8,530,962
4	Total Revenue (D-3)	$1,024,606		$46,319,660
	Average Lag in Payment of Operation and Maintenance Expense			
5	Payroll	$87,338	12	$1,048,056
6	Employee benefits	28,838	35	1,009,330
7	Affiliate support costs	94,519	35	3,308,165
8	Other operating expenses	345,849	41 *40*	14,179,809
9	Total pro forma O&M expense (b)	$556,544		$19,545,360
10	Average lag in receipt of revenue			45.2
11	Average lag in payment of operating expense			35.1
12	Average lag in days between payment of operating expense and receipt of revenue (line 10 - line 11)			10.1
13	Operating expense per day (line 9 ÷ 365 days)			$1,525
14	Working capital requirement (line 13 x line 12)			$15,403

		Customer Due Date		
		15 days	20 Days	30 Days
(a)	Midpoint of 30-day service period	15	15	15
	Lag between meter reading and billing date	1	1	1
	Lag between billing date and payment date	18	41	22
		34	57	38

(b)	Proforma operating and maintenance expense (D-1)	$583,402
	Less: Non-cash items	
	Uncollectible accounts expense per books (B-4)	20,747
	OnTrack uncollectible expense (D-8)	4,500
	Amortization of Ice and Snow Storm costs (D-9)	1,611
	Total pro forma O&M expense	$556,544

PPL Electric Utilities Corporation
Lag in Days in Payment of Operating Expenses
6 Months Ended September 30, 2006

	Lag in Days
Payroll Lag between the midpoint of the 14 day payroll period and pay day (payroll period ends on a Sunday and employees are paid on the following Friday).	12
Benefits Lag between the midpoint of the calendar month when services are provided through PPL Services Corp. and the payment on the 20th of the following month.	35
Affiliate Support Costs Lag between the midpoint of the calendar month when services are provided and the payment on the 20th of the following month.	35
Other Operating Expenses Lag between the receipt of services and materials and payment of invoices based on a review of selected invoices.	41

PPL Electric Utilities Corporation
Lag in Payment of Payroll & Benefits
6 Months Ended September 30, 2006

Payroll	Number of Days
Midpoint of 14 day payroll period	7
Lag between the end of the payroll period and the pay day (payroll period ends on a Sunday and employees are paid on the following Friday)	5
	12

Benefits	Number of Days
Lag between the midpoint of the calendar month when services are provided through PPL Services Corp. and the payment on the 20th of the following month	35

Affillate Support Costs	Number of Days
Lag between the midpoint of the calendar month when services are provided and the payment on the 20th of the following month	35

PPL Electric Utilities Corporation
Lag in Payment of Other Expenses
6 Months Ended Sept 30, 2006

Category		Amount	Days Lag	Weighted Amount
Employee Expenses*		$ 1,105,261	12.00	$ 13,263,132
Materials & Supplies	1/	1,805,688	**32.52**	58,720,974
Printing & Office Supplies	1/	345,256	**37.39**	12,909,122
Tree Trimming	1/	13,795,965	**52.66**	726,495,517
Work by Outsiders	1/	14,084,432	**65.64**	924,502,116
Services		3,289,341	20.19	66,411,795
Postage		2,652,900	-7.02	(18,623,358)
Telephone & Leased Wires		1,803,302	35.78	64,522,146
Rents		5,926,266	16.09	95,353,620
Advertising		115,679	34.91	4,038,354
Miscellaneous		3,171,040	4.14	13,128,106
Total		$48,095,130		$1,960,721,523
Weighted Average Lag = Total Weighted Amount / Total Amount =			40.77	

* The majority of employee expenses are processed on a pay period basis, accordingly, the 12-day payroll lag is deemed to be representative

Note:
1/ See respective detail on attached pages

PPL Electric Utilities Corporation
Lag in Payment of Materials - BI 25
6 Months Ended Sept 30, 2006
(Revised for Signalcrafters Tech Days Lag)

Vendor Name		Voucher Number	Invoice Number	Mid-point of Service Date	Payment Date	(A) Amount	(B) Days Lag	(A) x (B) Weighted Amount
DENT INSTRUMENTS		2347790	56379	04/03/06	05/03/06	$59,500.00	30	$1,785,000
SAS INSTITUTE INC		2349086	7127295	04/05/06	05/05/06	34,530.00	30	1,035,900
DENT INSTRUMENTS		2343856	56364	03/24/06	04/24/06	29,750.00	31	922,250
DENT INSTRUMENTS		2347790	56379	04/03/06	05/03/06	25,500.00	30	765,000
DENT INSTRUMENTS		2343856	56364	03/24/06	04/24/06	13,515.00	31	418,965
Achieveglobal Inc		2354063	I361984	03/31/06	04/18/06	13,515.00	18	243,270
MEHTA TECH INC		2385081	4149	05/31/06	06/30/06	12,000.00	30	360,000
Trench Limited		2343788	06Y2441	03/17/06	04/17/06	6,960.00	31	215,760
ARNCO CORPORATION		2347856	77440	04/04/06	05/04/06	4,815.00	30	144,450
Airgas East		2391955	116875563	06/06/06	07/06/06	3,594.12	30	107,824
SAS INSTITUTE INC		2349086	7127295	04/05/06	05/05/06	2,932.80	30	87,984
SENSORLINK CORP		2343698	43282	03/30/06	05/01/06	2,299.00	32	73,568
COOPER POWER SYSTEMS		2370420	91875401	05/17/06	06/16/06	2,238.06	30	67,142
Credit Card Purchase			250979	06/02/06	07/04/06	1,957.60	32	62,643
TANGLWOOD LAKES COMMUNITY		2369135	51206	05/12/06	06/12/06	1,770.20	31	54,876
NOVA ELECTRIC		02407015	014183	06/30/06	07/31/06	15,135.00	31	469,185
RFL ELECTRONICS INC		02402522	92499	06/29/06	07/31/06	13,690.00	32	438,080
TMC Industries Inc		02408720	061153 1RA	07/12/06	08/11/06	12,937.50	30	388,125
PENNSY SUPPLY INC		02382268	1511781	05/20/06	07/17/06	2,270.52	58	131,690
WESTGATE GLOBAL LOGISTICS		02396952	266607	06/22/06	07/13/06	1,050.00	21	22,050
SIGNALCRAFTERS TECH INC	1/	02431449	3334	07/20/06	09/14/06	26,800.00	56	1,500,800
SIGNALCRAFTERS TECH INC	1/							
GE Parts Super Center		02427683	884 165399	08/08/06	09/07/06	24,890.73	30	746,722
G&W ELECTRIC CO		02433901	G93607	08/18/06	09/18/06	12,360.00	31	383,160
DENT INSTRUMENTS		02395156	56585	06/14/06	08/02/06	8,388.00	49	411,012
WESTGATE GLOBAL LOGISTICS		02434371	267156	08/21/06	09/05/06	2,750.00	15	41,250
TRENWA INC		02420553	20184	07/31/06	08/30/06	2,000.00	30	60,000
GEORGE S COYNE CHEMICAL CO INC		02415660	700397	07/18/06	08/17/06	1,509.00	30	45,270
PENNSYLVANIA TRANSFORMER		02432137	21073	08/18/06	09/25/06	5,500.00	38	209,000
MESA TECHNICAL ASSOCIATES INC		02438314	1889	08/29/06	09/28/06	3,389.00	30	101,670
A TO S METALS INC		02451007	11812	08/18/06	09/27/06	1,251.00	40	50,040
						$348,798		$11,342,686
								32.52 days

Notes:
1/ Revised to eliminate duplicate invoice.

PPL Electric Utilities Corporation
Lag in Payment of Printing and Office Supplies - BI 26
6 Months Ended Sept 30, 2006
(Revised for Credit Card Purchase Days Lag)

Vendor Name		Voucher Number	Invoice or Reference #	Mid-point of Service Date	Payment Date	(A) Amount	(B) Days Lag	(A) x (B) Weighted Amount
TAB PRODUCTS CO		2340023	50005324	1/27/06	4/11/06	$2,057.98	74	$152,291
CHARRETTE CORPORATION		2386334	92714247	5/30/06	6/29/06	1,772.17	30	53,165
Credit Card Purchase	1/		242732	3/19/06	4/14/06	1,292.96	26	33,617
Credit Card Purchase	1/		251659	6/6/06	7/7/06	1,022.89	31	31,710
CHAMBER OF COMMERCE		2367249	155	5/1/06	5/15/06	1,000.00	14	14,000
Credit Card Purchase	1/		248579	5/15/06	6/7/06	963.81	23	22,168
EDS Corporation		2369990	U2004844	4/28/06	5/29/06	750.02	31	23,251
Credit Card Purchase	1/		251037	6/5/06	6/28/06	656.82	23	15,107
Credit Card Purchase	1/		248579	4/24/06	6/7/06	613.87	44	27,010
Credit Card Purchase	1/		244478	4/3/06	5/3/06	548.03	30	16,441
Credit Card Purchase	1/		251287	6/2/06	6/28/06	481.60	26	12,522
DIRECT MAIL SERVICE & PRESS INC		2360880	17098	4/28/06	5/29/06	445.00	31	13,795
Credit Card Purchase	1/		0000254574	6/15/06	7/29/06	2,415.79	44	106,295
GRAYBAR ELECTRIC CO INC		2403100	918598037	6/29/06	7/31/06	1,975.63	32	63,220
Credit Card Purchase	1/		0000252107	5/26/06	7/18/06	497.36	53	26,360
Credit Card Purchase	1/		0000252107	5/26/06	7/18/06	432.21	53	22,907
Credit Card Purchase	1/		0000255463	7/14/06	8/8/06	1,773.00	25	44,325
ALPHAGRAPHICS		2410304	39159	7/13/06	9/13/06	450.00	62	27,900
Credit Card Purchase	1/		0000256799	6/20/06	8/23/06	2,415.79	64	154,611
Credit Card Purchase	2/		0000256774	7/17/06	8/17/06			0
Credit Card Purchase	1/		0000257867	7/14/06	8/29/06	557.76	46	25,657
Credit Card Purchase	1/		0000257646	8/7/06	8/25/06	1,259.42	18	22,670
Credit Card Purchase	1/		0000260621	9/8/06	9/26/06	1,315.18	18	23,673
EDS Corporation		2432226	U2045563	8/15/06	9/25/06	840.02	41	34,441
Credit Card Purchase	1/		0000261563	9/12/06	9/30/06	630.45	18	11,348
						$26,168		$978,481

Weighted Average Lag (A x B) / A 37.39 days

Notes:
1/ Revised midpoint of service date to reflect invoice date
2/ Deleted from sample - no invoice available

PPL Electric Utilities Corporation
Lag in Payment of Tree Trimming - BI 31
6 Months Ended Sept 30, 2006
(Revised for Asplundh Days Lag)

Vendor Name		Voucher Number	Invoice Number	Mid-point of Service Date	Payment Date	(A) Amount	(B) Days Lag	(A) x (B) Weighted Amount
JAFLO INC		2345528	909	**03/01/06**	**04/24/06**	$335,376.00	54	$18,110,304
ASPLUNDH TREE EXPERT CO	1/	2344593	07A572			183,085.30	**52**	9,520,436
ASPLUNDH TREE EXPERT CO	1/	2344583	09B527			48,757.50	**52**	2,535,390
JAFLO INC		2340512	912	**03/21/06**	**04/24/06**	18,809.25	34	639,515
DINCHER & DINCHER		2371673	DIN T 16	**04/12/06**	**05/24/06**	123,950.00	42	5,205,900
ASPLUNDH TREE EXPERT CO	1/	2363670	116145			23,275.50	**52**	1,210,326
JAFLO INC		2365989	908	**03/07/06**	**05/18/06**	17,552.16	72	1,263,756
LEWIS TREE SERVICE INC		2359196	1272351 IN	**04/12/06**	**05/22/06**	14,297.50	40	571,900
JAFLO INC		2365989	908	**03/07/06**	**05/18/06**	12,430.40	72	894,989
JAFLO INC		2385067	925	**05/10/06**	**07/05/06**	216,333.90	56	12,114,698
ASPLUNDH TREE EXPERT CO	1/	2380050	13E007			94,827.00	**52**	4,931,004
ASPLUNDH TREE EXPERT CO	1/	2380050	13E007			28,600.00	**52**	1,487,200
ASPLUNDH TREE EXPERT CO	1/	2408597	175702			12,510.00	**52**	650,520
ASPLUNDH TREE EXPERT CO	1/	2408522	175705			108,272.91	**52**	5,630,191
JAFLO INC		2419774	000931	**06/21/06**	**08/21/06**	46,000.50	61	2,806,031
JAFLO INC		2419774	000931	**06/21/06**	**08/21/06**	22,878.75	61	1,395,604
ASPLUNDH TREE EXPERT CO	1/	2431283	27E052			10,135.18	**52**	527,029
JAFLO INC		2419774	000931	**07/21/06**	**08/21/06**	8,915.50	31	276,381
JAFLO INC		2420237	000934	**07/05/06**	**08/28/06**	5,883.62	54	317,715
ASPLUNDH TREE EXPERT CO	1/	2431307	23E055			272,639.00	**52**	14,177,228
ASPLUNDH TREE EXPERT CO	1/	2446817	195033			153,372.00	**52**	7,975,344
PNC Bank NA		2446427	31E056	**07/29/06**	**09/25/06**	83,228.12	58	4,827,231
JAFLO INC		2450680	000940	**08/16/06**	**10/06/06**	34,106.86	51	1,739,450
ASPLUNDH TREE EXPERT CO	1/	2431313	195037			26,015.00	**52**	1,352,780
ASPLUNDH TREE EXPERT CO	1/	2431314	29E056			18,951.48	**52**	985,477
ASPLUNDH TREE EXPERT CO	1/	2431299	29E055			14,760.00	**52**	767,520
ASPLUNDH TREE EXPERT CO	1/	2431327	27E056			7,973.88	**52**	414,642
ASPLUNDH TREE EXPERT CO	1/	2431313	195037			6,743.00	**52**	350,636
ASPLUNDH TREE EXPERT CO	1/	2431314	29E056			4,755.70	**52**	247,296
						$1,954,436		$102,926,492

Weighted Average Lag (A x B) / A — 52.66 days

Notes:
1/ Revised to apply 2007 lag days for Asplundh transactions to sample selections contained in 2006 lag study above.
2nd Q 2007 Asplundh Payment Lag of 52 days

PPL Electric Utilities Corporation
Lag in Payment of Work By Outsiders - BI 32
6 Months Ended Sept 30, 2006
(Revised for Henkels & McCoy Days Lag)

Vendor Name		Voucher Number	Invoice Number	Mid-point of Service Date	Payment Date	(A) Amount	(B) Days Lag	(A) x (B) Weighted Amount
HARLAN ELECTRIC CO		2345144	3067387	1/16/06	4/25/06	$114,873.10	99	$11,372,437
W A CHESTER LLC		2370287	600180-406	4/27/06	6/5/06	32,650.80	39	1,273,381
D L FRY INC		2363231	I200630	4/28/06	5/26/06	28,354.29	28	793,920
B J BALDWIN ELECTRIC INC		2368464	68253	4/30/06	5/29/06	25,980.00	29	753,420
AUTOMATED MICRO SYSTEMS		2389350	16962	12/16/05	7/28/06	23,010.00	224	5,154,240
AGROTORS INC		2343360	200620004	3/28/06	5/1/06	20,925.00	34	711,450
THE TREHAB CENTER		2342242	30106	3/16/06	5/1/06	19,140.00	46	880,440
AGROTORS INC		2368185	200620008	5/3/06	6/5/06	18,225.00	33	601,425
UTILITIES INTERNATIONAL INC		2388107	PPLEUCBS2605	5/16/06	7/3/06	17,736.49	48	851,352
HENKELS & MCCOY INC	1/	2333064	PPLA01I3827	3/8/06	4/13/06	17,410.64	36	626,783
WASTE MANAGEMENT OF PA, INC		2357174	79586	4/11/06	5/11/06	15,158.69	30	454,761
WASTE MANAGEMENT OF PA, INC		2373241	80340	5/12/06	6/14/06	14,274.40	33	471,055
STEP INC		2379457	S	5/16/06	6/6/06	13,979.25	21	293,564
COMMISSION ON ECONOMIC OPPORTUNITY		2377749	20064	4/15/06	6/5/06	12,460.00	51	635,460
KT POWER INC		2371899	11474	4/24/06	6/8/06	11,962.92	45	538,331
ABB INC		2363642	2709087	4/28/06	5/29/06	11,365.00	31	352,315
METROPOLITAN EDISON CO		1964155	INTERCONNECT-22	5/16/06	6/1/06	11,055.00	16	176,880
HENKELS & MCCOY INC	1/	2386318	PPLA06I1157	5/24/06	6/29/06	10,560.11	36	380,164
HENKELS & MCCOY INC	1/	2356911	PPLA06I1020	4/5/06	5/19/06	9,814.28	44	431,828
ALLIANCEONE RECEIVABLES		2387064	14282	5/16/06	6/30/06	9,263.81	45	416,871
UTILITIES INTERNATIONAL INC		2404750	PPLEUCBS2603	3/15/06	7/13/06	30,683.80	120	3,682,056
East Coast Drilling and Trenching LLC		2398583	062206PPL31	6/22/06	7/24/06	24,999.00	32	799,968
HENKELS & MCCOY INC	1/	2391791	PPLA06 I1168	5/31/06	7/7/06	23,121.50	37	855,496
THE TREHAB CENTER		2412633	60106	6/15/06	7/31/06	20,097.00	46	924,462
HENKELS & MCCOY INC	1/	2379235	PPLA06 I1120	5/10/06	7/13/06	17,268.01	64	1,105,153
DUGGAN & MARCON INC		2406727	6161AA	7/11/06	8/10/06	16,500.00	30	495,000
Osmose Utilities Services Inc		2355012	72 6300061	4/12/06	7/26/06	15,219.37	105	1,598,034
KT Power Inc		2407492	11485	5/18/06	7/27/06	12,482.74	70	873,792
HENKELS & MCCOY INC	1/	2425895	PPLA06 I1341	7/26/06	9/1/06	25,729.38	37	951,987
WASTE MANAGEMENT OF PA, INC.		2428609	82530	7/5/06	9/11/06	13,594.11	68	924,399
AGROTORS INC		2429653	20062001 27	8/4/06	9/11/06	13,500.00	38	513,000
EVERHART & HOOVER POWER LINE		2425123	080706 3	7/29/06	9/6/06	11,648.71	39	454,300
LINEAL INDUSTRIES INC		2422657	248859	7/21/06	9/1/06	10,406.00	42	437,052
MILLER BROS		2331532	602 003	3/8/06	9/14/06	68,691.00	190	13,051,290
HENKELS & MCCOY INC	1/	2448612	PPLA06 I1451	8/30/06	10/6/06	47,304.25	37	1,750,257
PAVEMASTERS		2446433	081506	8/15/06	10/4/06	35,793.00	50	1,789,650
AGROTORS INC		2449617	20062001 34	9/13/06	10/16/06	28,350.00	33	935,550
THE TREHAB CENTER		2439242	80106	8/15/06	10/2/06	21,791.00	48	1,045,968
AGROTORS INC		2433924	20062001 29	8/16/06	9/20/06	21,600.00	35	756,000
HENKELS & MCCOY INC	1/	2448751	PPLA06 I1449	8/30/06	10/6/06	18,822.24	37	696,423
HENKELS & MCCOY INC	1/	2449587	PPLA06 I1461	8/30/06	10/6/06	11,241.83	37	415,948
D L FRY INC.		2439841	I200658	9/1/06	10/2/06	10,779.36	31	334,160
						$937,821		$61,560,022
			Weighted Average Lag (A x B) / A				65.64 days	

Notes:
1/ *Reflects midpoint of service based on weekly billing cycles*

PPL Electric Utilities Corporation
Lag in Payment of Services - BI 33
6 Months Ended Sept 30, 2006

Vendor Name	Voucher Number	Invoice Number	Mid-point of Service Date	Payment Date	(A) Amount	(B) Days Lag	(A) x (B) Weighted Amount
Accenture	2358174	9990212621	**05/15/06**	**05/01/06**	$335,507.63	(14)	($4,697,107)
Accenture	2355126	1000074272	**04/03/06**	**05/03/06**	176,849.00	30	5,305,470
Accenture	2357800	9990212624	**05/15/06**	**05/01/06**	49,808.00	(14)	(697,312)
EPRI	2339328	EP00283667	**05/15/06**	**05/01/06**	26,447.00	(14)	(370,258)
Accenture	2357800	9990212624	**05/15/06**	**05/01/06**	24,904.00	(14)	(348,656)
Onyx Environmental Services LLC	2337730	606869388	**03/21/06**	**04/20/06**	8,470.81	30	254,124
ICR	2346412	8481	**04/05/06**	**05/05/06**	3,925.00	30	117,750
EXECUTIVE RELOCATION CORPORATION	2325565	6450 3117 06	**01/15/06**	**03/17/06**	3,230.85	61	197,082
PENNSYLVANIA ONE CALL SYSTEM INC	2345968	215076	**3/31/2006**	**05/01/06**	2,386.80	31	73,991
J D Power and Associates	2345155	46657	**03/21/06**	**04/20/06**	55,000.00	30	1,650,000
APPLIED PUBLIC POLICY RESEARCH	2366575	6022	**05/01/06**	**06/02/06**	29,965.00	32	958,880
M & T BANK	2372041	EL05 121	**04/24/06**	**05/23/06**	24,035.00	29	697,015
ICR	2363685	8588	**05/01/06**	**05/31/06**	15,258.75	30	457,763
GROSS MCGINLEY LABARRE & EATON LLP	2373288	63 030	**03/18/06**	**05/25/06**	5,460.90	68	371,341
PENNSYLVANIA ONE CALL SYSTEM INC	2363430	218854	**04/30/06**	**05/30/06**	2,820.60	30	84,618
EXECUTIVE RELOCATION CORPORATION	2358991	6450 3146 06	**03/15/06**	**05/01/06**	2,697.45	47	126,780
UTILITIES INTERNATIONAL INC	2344907	PPLEUAS512	**12/15/05**	**06/30/06**	55,390.47	197	10,911,923
UTILITIES INTERNATIONAL INC	2388942	PPLEUWST604	**04/20/06**	**06/30/06**	15,457.68	71	1,097,495
Accenture	2415632	1000086984	**08/15/06**	**07/31/06**	335,507.63	-15	(5,032,614)
EPRI	2401544	EP00290751	**08/15/06**	**07/31/06**	26,447.00	-15	(396,705)
DAVIES CONSULTING INC	2407259	06 698	**04/15/06**	**07/31/06**	18,332.12	107	1,961,537
ICR	2405483	008859	**08/15/06**	**08/04/06**	11,472.50	-11	(126,198)
EXECUTIVE RELOCATION CORPORATION	2404190	6450 0946 06	**05/15/06**	**07/14/06**	5,357.76	60	321,466
DAVIES CONSULTING INC	2429905	06 707	**07/01/06**	**08/30/06**	27,901.72	60	1,674,103
PENNSYLVANIA ONE CALL SYSTEM INC	2421690	0000224455	**07/31/06**	**08/30/06**	3,115.80	30	93,474
Accenture	2448503	1000094209	**07/01/06**	**09/26/06**	150,000.00	87	13,050,000
Accenture	2450239	1000095484	**09/01/06**	**09/26/06**	117,250.00	25	2,931,250
J D Power and Associates	2438192	49390	**08/22/06**	**09/21/06**	74,200.00	30	2,226,000
Accenture	2450239	1000095484	**09/01/06**	**09/26/06**	57,750.00	25	1,443,750
SIEMENS POWER TRANSMISSION & DIST INC	2447028	50018350	**09/01/06**	**10/02/06**	57,650.00	31	1,787,150
J D Power and Associates	2430876	49134	**07/31/06**	**09/14/06**	47,700.00	45	2,146,500
EXECUTIVE RELOCATION CORPORATION	2420296	6450 0953 06	**06/15/06**	**09/05/06**	31,685.46	82	2,598,208
Electrocon International Inc	2438362	5863	**03/01/07**	**09/25/06**	12,637.32	-157	(1,984,059)
General Electric International Inc	2449903	PSLF 0044 07	**06/30/07**	**10/02/06**	8,400.00	-271	(2,276,400)
EXECUTIVE RELOCATION CORPORATION	2420296	6450 0953 06	**06/15/06**	**09/05/06**	2,755.01	82	225,911
PENNSYLVANIA ONE CALL SYSTEM INC	2441107	0000226360	**08/31/06**	**10/02/06**	1,972.80	32	63,130
					$1,827,750		$36,897,400

Weighted Average Lag (A x B) / A 20.19 days

PPL Electric Utilities Corporation
Lag in Payment of Postage - BI 34
6 Months Ended Sept 30, 2006

Vendor Name	Voucher Number	Invoice Number	Mid-point of Service Date	Payment Date	(A) Amount	(B) Days Lag	(A) x (B) Weighted Amount
DST OUTPUT	2311987	PROCESS POSTAGE BILL-2	**04/17/06**	**04/10/06**	209,000.00	(7)	($1,463,000)
DST OUTPUT	2312089	PROCESS POSTAGE BILLING-3	**05/01/06**	**04/25/06**	209,000.00	(6)	(1,254,000)
DST OUTPUT	2312090	PROCESS POSTAGE BILLING-4	**06/01/06**	**05/25/06**	209,000.00	(7)	(1,463,000)
DST OUTPUT	2311988	PROCESS POSTAGE BILL-3	**05/17/06**	**05/10/06**	209,000.00	(7)	(1,463,000)
DST OUTPUT	2311989	PROCESS POSTAGE BILL-4	**06/17/06**	**06/09/06**	209,000.00	(8)	(1,672,000)
DST OUTPUT	2312091	PROCESS POSTAGE BILLING-5	**07/02/06**	**06/23/06**	209,000.00	(9)	(1,881,000)
UNITED STATES POSTAL SERVICE	2381051	35653955 POSTAGE MAY	**05/15/06**	**06/05/06**	12,000.00	21	252,000
UNITED STATES POSTAL SERVICE	2395158	061506 POSTAGE	**06/15/06**	**06/28/06**	2,000.00	13	26,000
DST OUTPUT *	2311990	PROCESS POSTAGE BILL-5	**07/17/06**	**07/10/06**	209,000.00	-7	(1,463,000)
DST OUTPUT *	2312092	PROCESS POSTAGE BILLING-6	**08/01/06**	**07/25/06**	209,000.00	-7	(1,463,000)
DST OUTPUT *	2311991	PROCESS POSTAGE BILL-6	**08/17/06**	**08/10/06**	209,000.00	-7	(1,463,000)
DST OUTPUT *	2312093	PROCESS POSTAGE BILLING-7	**09/01/06**	**08/25/06**	209,000.00	-7	(1,463,000)
DST OUTPUT *	2311992	PROCESS POSTAGE BILL-7	**09/17/06**	**09/08/06**	209,000.00	-9	(1,881,000)
DST OUTPUT *	2312094	PROCESS POSTAGE BILLING-8	**10/02/06**	**09/25/06**	209,000.00	-7	(1,463,000)
UNITED STATES POSTAL SERVICE	2455349	35653955 POSTAGE SEPTEMBER	**09/15/06**	**10/02/06**	12,000.00	17	204,000
DIRECT MAIL SERVICE & PRESS INC	2410614	AUGPOSTAGE	**08/15/06**	**09/01/06**	5,000.00	17	85,000
					$2,539,000		($17,825,000)

Weighted Average Lag (A x B) / A -7.02 days

PPL Electric U[illegible]ies Corporation
Lag in Payment of [illegible]nes and Wires - BI 35
6 Months Ended Sept 30, 2006

Vendor Name	Voucher Number	Invoice Number	Mid-point of Service Date	Payment Date	(A) Amount	(B) Days Lag	(A) x (B) Weighted Amount
VERIZON WIRELESS	2369057	42806000366	**04/28/06**	**05/19/06**	$53,739.58	21	$1,128,531
VERIZON	2345354	215 190 6820 999 24 Y	**03/01/06**	**04/12/06**	47,550.00	42	1,997,100
VERIZON	2353066	215 190 6820 999 24 Y	**04/01/06**	**05/09/06**	47,550.00	38	1,806,900
VERIZON	2367436	215 190 6820 999 24 Y	**05/01/06**	**06/28/06**	47,550.00	58	2,757,900
VERIZON	2389576	215 190 6820 999 24Y	**06/01/06**	**06/23/06**	47,550.00	22	1,046,100
VERIZON	2398588	71948135	**05/15/06**	**06/29/06**	30,156.00	45	1,357,020
VERIZON	2353066	215 190 6820 999 24 Y	**04/01/06**	**05/09/06**	30,120.00	38	1,144,560
VERIZON	2367436	215 190 6820 999 24 Y	**05/01/06**	**06/28/06**	30,120.00	58	1,746,960
VERIZON	2389576	215 190 6820 999 24Y	**06/01/06**	**06/23/06**	30,120.00	22	662,640
VERIZON	2345354	215 190 6820 999 24 Y	**03/01/06**	**04/12/06**	29,231.60	42	1,227,727
ATX TELECOMMUNICATIONS SERVICES	2353906	8003425775	**03/25/06**	**04/25/06**	22,874.09	31	709,097
VERIZON	2348623	215197856599902Y	**04/01/06**	**04/17/06**	22,764.31	16	364,229
ATX TELECOMMUNICATIONS SERVICES	2353906	8003425775	**03/25/06**	**04/25/06**	10,007.41	31	310,230
MCI	2350203	70007756	**04/10/06**	**06/14/06**	4,677.18	65	304,017
VERIZON	2398588	71948135	**05/15/06**	**06/29/06**	3,769.51	45	169,628
SCHUYLKILL MOBILE FONE INC	2366161	31734569	**05/01/06**	**05/23/06**	3,180.00	22	69,960
VERIZON	2387639	717193346599910Y	**06/01/06**	**06/16/06**	2,542.14	15	38,132
MCI	2350203	70007756	**04/10/06**	**06/14/06**	2,046.27	65	133,008
VERIZON	2406892	71949560	**06/15/06**	**07/14/06**	34,450.21	29	999,056
VERIZON	2406892	71949560	**06/15/06**	**07/14/06**	15,071.97	29	437,087
GRAYBAR ELECTRIC CO INC	2403112	918582413	**06/28/06**	**07/28/06**	7,081.36	30	212,441
VERIZON	2408070	717193346599910Y	**07/01/06**	**07/19/06**	2,522.62	18	45,407
CINGULAR WIRELESS	2377747	2077164	**04/21/06**	**07/05/06**	2,079.13	75	155,935
VERIZON WIRELESS	2419451	52806000366	**05/28/06**	**08/03/06**	59,458.25	67	3,983,703
VERIZON WIRELESS	2419454	72806000366	**07/28/06**	**08/04/06**	50,884.49	7	356,191
VERIZON	2411589	215 190 6820 999 24 Y	**07/01/06**	**08/16/06**	47,550.00	46	2,187,300
MCI	2417792	07656622	**07/10/06**	**08/02/06**	37,019.67	23	851,452
VERIZON	2411589	215 190 6820 999 24 Y	**07/01/06**	**08/16/06**	30,120.00	46	1,385,520
VERIZON	2410964	215197856599902Y	**07/01/06**	**08/08/06**	21,622.15	38	821,642
VERIZON	2425404	215197856599902Y	**08/01/06**	**08/24/06**	21,616.67	23	497,183
MCI	2417792	07656622	**07/10/06**	**08/12/06**	16,196.10	33	534,471
EMBARQ	2416716	7171271000958	**07/25/06**	**08/08/06**	3,908.15	14	54,714
SCHUYLKILL MOBILE FONE INC	2421916	31757571	**08/01/06**	**08/10/06**	3,180.00	9	28,620
VERIZON	2427455	215190682099924Y	**08/01/06**	**09/08/06**	47,550.00	38	1,806,900
MCI	2438113	08297701	**08/10/06**	**09/07/06**	37,701.21	28	1,055,634
VERIZON	2427455	215190682099924Y	**08/01/06**	**09/08/06**	30,120.00	38	1,144,560
MCI	2438113	08297701	**08/10/06**	**09/07/06**	16,494.28	28	461,840
					$950,174		$33,993,395

Weighted Average Lag (A x B) / A

35.78 days

PPL Electric Utilities Corporation
Lag in Pay[redacted]f Rents - BI 36
6 Months Ended Sept 30, 2006

Vendor Name	Voucher Number	Invoice Number	Mid-point of Service Date	Payment Date	(A) Amount	(B) Days Lag	(A) x (B) Weighted Amount
JEDDO-HIGHLAND COAL CO	2019535	LAND RENTS R/W-3	01/01/07	07/03/06	$1,471.00	(182)	($267,722)
Freya Land Company	0404300	ATTACH R/W-9	01/01/07	07/01/06	897.00	(184)	-165,048
MET-ED	2414311	90144632	08/15/06	07/27/06	806.00	(19)	-15,314
HV DIAGNOSTICS		Monthly Lease JE 322	07/15/06	08/01/06	2,609.66	17	44,364
DOBLE ENGINEERING		Monthly Lease JE 322	07/15/06	08/01/06	1,400.53	17	23,809
DILO CO.		Monthly Lease JE 322	07/15/06	08/01/06	1,235.74	17	21,008
IPC INFORMATIONAL SYSTEM		Monthly Lease JE 322	07/15/06	07/31/06	1,164.38	16	18,630
IPC INFORMATION SYSTEMS		Monthly Lease JE 322	07/15/06	07/31/06	4,540.27	16	72,644
HV TECHNOLOGIES		Monthly Lease JE 322	07/15/06	07/31/06	2,082.54	16	33,321
DOBLE EQUIPMENT		Monthly Lease JE 322	07/15/06	08/01/06	1,495.30	17	25,420
CLEVELAND BROS.		Monthly Lease JE 322	07/15/06	08/01/06	1,411.90	17	24,002
CENTRAL PENN DIRECTIONAL DRILLING INC	2415641	865	07/19/06	08/18/06	5,778.00	30	173,340
D L FRY INC.	2416049	I 200653	07/25/06	09/01/06	1,372.28	38	52,147
D L FRY INC.	2413137	I 200650	07/19/06	08/25/06	7,847.00	37	290,339
DILO CO.		Monthly Lease JE 322	08/15/06	09/01/06	1,622.76	17	27,587
IPC INFORMATION SYSTEMS		Monthly Lease JE 322	08/15/06	08/31/06	4,531.84	16	72,509
HV TECHNOLOGIES		Monthly Lease JE 322	08/15/06	08/31/06	2,086.47	16	33,384
DOBLE EQUIPMENT		Monthly Lease JE 322	08/15/06	09/01/06	1,491.52	17	25,356
CLEVELAND BROS.		Monthly Lease JE 322	08/15/06	09/01/06	1,407.62	17	23,930
CITY OF HARRISBURG	2447582	06080008	08/01/06	09/21/06	3,969.00	51	202,419
CLEVELAND BROTHERS EQUIP CO INC	2450711	R5631904	09/12/06	10/02/06	3,705.00	20	74,100
United Rentals Inc.	2438466	58669902 001	08/17/06	09/18/06	2,508.24	32	80,264
HERTZ EQUIPMENT RENTAL	2448341	20941925 005	08/24/06	10/10/06	1,908.00	47	89,676
HERTZ EQUIPMENT RENTAL	2421834	8708541 017	07/15/06	08/29/06	1,200.00	45	54,000
AAT COMMUNCIATIONS SYSTEMS CORPORATION	2445269	665836	08/22/06	09/20/06	2,146.44	29	62,247
IPC INFORMATION SYSTEMS		Monthly Lease JE322	04/15/06	04/30/06	4,566.73	15	68,501
HV DIAGNOSTICS		Monthly Lease JE322	04/15/06	05/01/06	2,554.71	16	40,875
HV TECHNOLOGIES		Monthly Lease JE322	04/15/06	04/30/06	2,076.19	15	31,143
United Rentals Inc.	2341286	42686355 022	03/16/06	04/14/06	1,909.12	29	55,364
CITY OF HARRISBURG	2353899	5110063	03/15/06	04/25/06	1,863.00	41	76,383
DILO CO.		Monthly Lease JE322	04/15/06	05/01/06	1,589.12	16	25,426
CLEVELAND BROTHERS EQUIP CO INC	2352460	R6101133	03/04/06	04/25/06	1,316.00	52	68,432
IPC INFORMATION SYSTEMS		Monthly Lease JE322	05/15/06	05/31/06	4,570.58	16	73,129
NRPC - AMTRAK	2359319	583432	11/01/06	05/31/06	3,162.51	(154)	-487,027
HV DIAGNOSTICS		Monthly Lease JE322	05/15/06	06/01/06	2,589.79	17	44,026
HV TECHNOLOGIES		Monthly Lease JE322	05/15/06	05/30/06	2,088.32	15	31,325
DILO CO.		Monthly Lease JE322	05/15/06	06/01/06	1,612.09	17	27,406
CLEVELAND BROS.		Monthly Lease JE322	05/15/06	06/01/06	1,408.61	17	23,946
IPC INFORMATION SYSTEMS		Monthly Lease JE322	05/15/06	06/01/06	1,195.91	17	20,330
IPC INFORMATIONAL SYSTEM		Monthly Lease JE322	05/15/06	05/31/06	1,171.89	16	18,750
IPC INFORMATION SYSTEMS		Monthly Lease JE322	05/15/06	06/01/06	1,099.55	17	18,692
IPC INFORMATION SYSTEMS		Monthly Lease JE322	06/15/06	06/30/06	4,543.07	15	68,146
CLEVELAND BROTHERS EQUIP CO INC	2372888	T0980801	04/15/06	06/07/06	2,963.55	53	157,068
HV DIAGNOSTICS		Monthly Lease JE322	06/15/06	07/01/06	2,568.30	16	41,093
SONNY'S	2378364	3602	05/02/06	06/02/06	2,370.00	31	73,470
HV TECHNOLOGIES		Monthly Lease JE322	06/15/06	06/30/06	2,074.60	15	31,119
CLEVELAND BROTHERS EQUIP CO INC	2379032	R5556101	05/04/06	06/12/06	2,020.00	39	78,780
CITY OF HARRISBURG	2397375	255 3141	05/15/06	06/30/06	1,782.00	46	81,972
CLEVELAND BROTHERS EQUIP CO INC	2372889	T0984901	04/19/06	06/07/06	1,690.00	49	82,810
DILO CO.		Monthly Lease JE322	06/15/06	07/01/06	1,598.53	16	25,576
CLEVELAND BROTHERS EQUIP CO INC	2395875	P8359901	05/30/06	07/07/06	1,385.00	38	52,630
DILO CO.		Monthly Lease JE322	06/15/06	07/01/06	1,215.14	16	19,442
DOBLE ENGINEERING		Monthly Lease JE322	06/15/06	07/01/06	861.91	16	13,791
					$120,535		$1,939,011

Weighted Average Lag (A x B) / A — *16.09 days*

PPL Electric Utilities Corporation
Lag in Payment of Advertising Expenses - BI 37
6 Months Ended Sept 30, 2006

Vendor Name	Voucher Number	Invoice Number	Mid-point of Service Date	Payment Date	(A) Amount	(B) Days Lag	(A) x (B) Weighted Amount
Precision Design	2382500	D117183	**05/18/06**	**06/19/06**	$7,750.00	32	$248,000
BERKS ECONOMIC PARTNERSHIP	2374793	33195	**05/10/06**	**06/09/06**	4,000.00	30	120,000
THE DUBBS CO	2391430	178070B	**06/07/06**	**07/07/06**	2,600.00	30	78,000
CARBON COUNTY ECON DEV CORP	2349732	40506	**04/05/06**	**05/03/06**	2,500.00	28	70,000
COLUMBIA-MONTOUR PA IMAGE BOOK	2363775	19	**04/27/06**	**06/27/06**	2,495.00	61	152,195
Focus Central Pennsylvania	2351169	5579 078	**03/31/06**	**04/21/06**	2,152.38	21	45,200
Precision Design	2380630	D117154B	**05/19/06**	**06/19/06**	1,725.00	31	53,475
POTTSVILLE REPUBLICAN &	2371439	1618892	**04/30/06**	**05/22/06**	1,650.60	22	36,313
Westlawn Graphic	2393739	61506	**06/15/06**	**07/17/06**	1,572.00	32	50,304
HAZLETON STANDARD-SPEAKER INC	2369942	10070577	**04/30/06**	**05/30/06**	1,560.00	30	46,800
Total Imaging Inc	2330077	34572	**03/09/06**	**04/19/06**	1,475.00	41	60,475
PENN'S NORTHEAST	2413473	071306	**07/13/06**	**07/26/06**	8,250.00	13	107,250
THE SCRANTON PLAN	2401496	JUNE 7 2006	**06/07/06**	**07/19/06**	5,000.00	42	210,000
PENNSYLVANIA ONE CALL SYSTEM INC	2415700	0000215811	**04/27/06**	**07/28/06**	2,855.80	92	262,734
Focus Central Pennsylvania	2413729	5579 084	**07/14/06**	**07/26/06**	2,343.00	12	28,116
HAZLETON STANDARD-SPEAKER INC	2413695	10070577	**06/30/06**	**07/31/06**	1,548.00	31	47,988
CHAMBER OF COMMERCE	2407204	QL07 31	**07/03/06**	**07/18/06**	1,400.00	15	21,000
Greater Hazleton Chamber of Commerce	2416338	632	**07/20/06**	**08/21/06**	975.00	32	31,200
Precision Design	2435877	2	**08/16/06**	**09/15/06**	2,100.00	30	63,000
VERIZON	2410568	0045716338	**11/26/05**	**09/01/06**	540.00	279	150,660
THE LAMAR COMPANIES	2454442	9740718	**08/25/06**	**10/02/06**	6,250.00	38	237,500
THE DUBBS CO	2442105	181758	**08/09/06**	**09/13/06**	2,520.09	35	88,203
					$63,262		$2,208,413

Weighted Average Lag (A x B) / A 34.91 days

PPL Electric [redacted]ies Corporation
Lag in Payment of Mi[redacted]aneous Expenses - BI 49
6 Months Ended Sept 30, 2006

Vendor Name	Voucher Number	Invoice / Reference Number	Mid-point of Service Date	Payment Date	(A) Amount	(B) Days Lag	(A) x (B) Weighted Amount
TIM ROTHERMEL	*2347574*	*83060 43003*	***03/16/06***	***04/13/06***	*$3,386.01*	*28*	*$94,808*
MENNO EBY	2353981	6022	**03/20/06**	**04/25/06**	2,311.29	36	83,206
ALLSTATE INSURANCE CO	2344979	5133140177F2F	**04/01/06**	**04/11/06**	1,700.00	10	17,000
SERGEI SZORTYKA	2343093	6019	**03/20/06**	**04/07/06**	1,514.05	18	27,253
ANDREW SOBACK	2343291	31750 53007	**03/21/06**	**04/07/06**	1,490.00	17	25,330
Credit Card Purchase		243636	**03/07/06**	**04/24/06**	7,950.00	48	381,600
HOMELAND	2355899	HOMELAND SETTLEMENT 0306	**03/21/06**	**05/16/06**	6,404.00	56	358,624
ALLSTATE INSURANCE CO	2369342	5133205483	**11/11/05**	**05/17/06**	4,731.79	187	884,845
THE PHOENIX INSURANCE COMPANY	2357651	278FRUVA0511P	**04/13/06**	**05/01/06**	4,131.30	18	74,363
NATIONWIDE INSURANCE	2359565	58011	**04/25/06**	**05/02/06**	2,479.55	7	17,357
ALLSTATE INSURANCE CO	2369782	5133082007KLA	**07/15/05**	**05/19/06**	2,011.32	308	619,487
DONALD ZEISLOFT	2345014	PD 2006 06	**04/03/06**	**04/10/06**	1,684.32	7	11,790
RELIABILITY FIRST CORPORATION	2382639	165	**08/15/06**	**07/03/06**	74,027.13	(43)	(3,183,167)
PJM Bill		JEF2982378	**06/15/06**	**07/20/06**	16,863.73	35	590,231
PJM Bill		JEF2987775	**06/15/06**	**07/20/06**	15,262.71	35	534,195
NORTH AMERICAN ENERGY STANDARDS	2387757	4591	**03/01/07**	**08/11/06**	5,000.00	(202)	(1,010,000)
ROSENBERG & PARKER INC	2374576	B45420 16 1	**11/03/06**	**06/12/06**	4,500.00	(144)	(648,000)
WHITTAKER ASSOCIATES	2393312	20062189	**06/02/06**	**07/07/06**	3,404.92	35	119,172
JOSEPH KAVITSKI	2385014	1303033008	**05/08/06**	**06/12/06**	3,102.48	35	108,587
ALLSTATE INSURANCE CO	2386143	5133322783 F9Y	**04/18/06**	**06/13/06**	3,079.18	56	172,434
ERIE INSURANCE GROUP	2390662	10180757012	**06/06/06**	**06/22/06**	3,065.00	16	49,040
ERIE INSURANCE GROUP	2391529	10170854643	**06/08/06**	**06/22/06**	2,288.31	14	32,036
SUSAN ZINGARETTI	2393682	2006 10	**06/13/06**	**06/23/06**	1,865.86	10	18,659
CHARLES EBERHARDT	2389296	08821 31017	**06/12/06**	**06/19/06**	1,672.76	7	11,709
ENCOMPASS INSURANCE	2411159	57580 23009 NEBHUT	**04/24/06**	**07/21/06**	4,791.70	88	421,670
POCONO RABBIT FARM	2411147	78165 14009	**07/13/06**	**07/24/06**	4,750.00	11	52,250
LIBERTY MUTUAL	2401611	005972083 01	**06/21/06**	**07/06/06**	3,906.34	15	58,595
ALLEN C HENCH	2402441	PD HAR 06 019	**06/15/06**	**07/07/06**	2,730.08	22	60,062
ROBERT R PALMER	2407521	PD HAR 06 026	**05/23/06**	**07/18/06**	2,728.10	56	152,774
MERCHANTS MUTUAL INSURANCE CO	2415671	H 0016793 01	**02/07/06**	**07/28/06**	2,676.13	171	457,618
CAN DO INC	2404681	7	**06/23/06**	**07/13/06**	2,500.00	20	50,000
CAN DO INC	2413501	8	**07/12/06**	**07/26/06**	2,500.00	14	35,000
COMMONWEALTH OF PENNSYLVANIA	2397462	080187	**06/04/06**	**07/14/06**	1,782.00	40	71,280
PJM Bill		JEF2981850	**08/15/06**	**09/20/06**	25,177.99	36	906,408
COMMONWEALTH OF PA	2433340	18 06 1 138	**07/07/06**	**08/28/06**	24,880.25	52	1,293,773
LORI PEARSON	2428951	91096 88001	**08/08/06**	**08/21/06**	4,292.00	13	55,796
ANGEL RIEPHOFF	2422862	89661 26150	**07/25/06**	**08/10/06**	3,889.11	16	62,226
BKK COMMUNICATIONS INC	2421920	6043	**07/06/06**	**08/10/06**	2,188.37	35	76,593
GLENN G HOLZMANN	2428948	37233 48000	**08/10/06**	**08/21/06**	2,166.67	11	23,833
RELIABILITY FIRST CORPORATION	2447158	0000260	**11/15/06**	**10/02/06**	71,069.14	-44	(3,127,042)
PJM Bill		JEF2987390	**09/15/06**	**10/20/06**	47,867.50	35	1,675,363
RAYMOND PASSANTE	2448145	32545 19486	**08/24/06**	**09/22/06**	5,302.87	29	153,783
PREMIERE SPEAKERS BUREAU INC	2439908	12049	**12/08/06**	**09/08/06**	3,250.00	-91	(295,750)
DALE ROTH	*2454684*	692 9002 028	**09/25/06**	**09/29/06**	3,200.00	4	12,800
WESTFIELD INSURANCE	2448148	NR HOP 1429874 122405 A	**09/06/06**	**09/21/06**	2,475.00	15	37,125
PAUL PANZERA	2442248	2006 016	**08/31/06**	**09/13/06**	2,455.83	13	31,926
					$400,505		$1,656,641

Weighted Average Lag (A x B) / A 4.14 days

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00072155

PPL ELECTRIC UTILITIES CORPORATION

Statement No. 7-R

Rebuttal Testimony of Oliver G. Kasper

Rebuttal Testimony of Oliver G. Kasper

Q. Please state your full name and business address.

A. Oliver G. Kasper, Two North Ninth Street, Allentown, Pennsylvania, 18101.

Q. Have you previously presented testimony in this proceeding?

A. Yes. I submitted my direct testimony, Statement No. 7, on March 29, 2007.

Q. Mr. Kasper, what is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to:

1. Present updated distribution and transmission revenues to reflect the results of the Remand Settlement Agreement described in Mr. Kleha's supplemental direct testimony that was approved by the Public Utility Commission ("PUC" or the "Commission") on July 25, 2007, to be effective August 1, 2007, ("Remand Settlement").
2. Present an updated allocation of the requested rate increase to the customer classes, to reflect that Remand Settlement.
3. Respond to PPLICA witness Steve Baron and Richards Energy witness Frank Richards with regard to Rule 4 of the tariff.
4. Respond to certain rate structure issues and options proposed by OCA witness Richard A. Galligan and Mr. Richards.

Revisions to the Filing

Q. Please list the exhibits and attachments which are being revised to reflect the Remand Settlement Agreement.

A. Attachment 1 - Exhibit Future 1, Schedule D-3 – Summary Proof of Revenue - Revision

Attachment 2 - Attachment IV-C – Proofs of Revenue - Revision

Q. Please explain changes to Exhibit Future 1, Schedule D-3.

A. The revised Exhibit Future 1, Schedule D-3, pages 2 through 6 is included as Attachment 1 to my testimony. This attachment includes an additional page, 2A, sets forth the adjustments to the future test year budget required to reflect the Remand Settlement. The Remand Settlement changed the Distribution base rates as found in PPL Electric's currently effective Supplement No. 57, effective August 1, 2007. The Remand Settlement also modified transmission rates and thus the Transmission budget for the future test year. These rate changes are reflected as a modification of the Present Distribution Revenues and Present Transmission Revenues at Current Rates on page 3 of Exhibit Future 1, Schedule D-3.

For purposes of comparison, Table 1 below illustrates the changes from Exhibit Future 1, page 2, Budgeted for the 12 month period ending December 31, 2007, and the revised page 3 for Distribution and Transmission.

Table 1

Changes to Budget Revenues For Distribution and Transmission
12 Months Ending 12/31/2007

Rate	Page 2 Budget Distribution	Page 3 Remand Distribution	Change Distribution	Page 2 Budget Transmission	Page 3 Remand Transmission	Change Transmission
RS	$375,738,309	$386,343,017	$10,604,708	$77,978,133	$89,235,540	$11,257,407
RTS	3,683,000	3,990,636	307,636	2,183290	2,498,483	315,193
RTD	132,691	136,735	4,044	28,378	32,475	4,097
GS-1	75,415,309	73,585280	(1,830,029)	11,019,603	11,653,749	634,146
GS-3	115,677,144	109,752,651	(5,924,493)	49,129,868	51,897,747	2,767,879
LP-4	30,263,941	28,838,237	(1,425,704)	33,008,249	28,857,948	(4,150,301)
IS-P	1,800,382	1,765,281	(35,101)	1,962,576	1,806,132	(156,443)
LP-5	1,615,397	1,065,194	(550,203)	18,057,516	13,360,616	(4,696,900)
IS-T	713,399	538,503	(173,895)	11,309,318	7,321,987	(3,987,330)
LP-6	139,000	35,596	(103,404)	2,055,141	1,526,702	(528,439)
LPEP	331,000	333,125	2,125	406,884	630,589	223,705
ISA	526,600	526,600	-	1,491,906	529,528	(962,378)
IS-1	31,691	31,691	-	8,179	8,639	460
BL	280,856	280,856	-	36,556	38,615	2,059
SA	3,386,787	3,561,159	174,372	129,397	136,682	7,285
SM	888,622	933,723	45,101	32,236	34,076	1,840
SHS	10,968285	11,548,813	580,528	274,327	290,009	15,682
SE	1,396,986	1,436,561	39,575	201,942	213,319	11,377
TS	20,748	22,029	1,281	1,889	1,995	106
SI-1	14,572	15,337	765	492	520	28
GH-1	5,743,944	5,230,227	(513,716)	1,570,988	1,659,493	88,505
GH-2	1,356,056	1,229,243	(126,813)	363,742	384,235	20,493
Standby	45,000	34,955	(10,045)	37,197	7,859	(29,338)
Totals	$630,169,719	$631,235,451	$1,065,732	$211,287,807	$212,126,939	$839,133

Q. How did you develop this modification to the 2007 future test year budget revenues for the Remand Settlement?

A. In the Remand Settlement, new base rates were using the same data that was used for the original compliance filing submitted in January 2005. A Proof of Revenue (found in Appendix E of the Remand Settlement) was developed for each rate schedule. With approval of the Remand Settlement, these rates will become effective on August 1, 2007, and therefore, will be the new present rates for this case. The current Proofs of Revenue found in Attachment IV-C for the current

proceeding were updated using the Remand Settlement rates, which are included as Attachment 2 to this testimony, labeled Attachment IV-C Revision.

To arrive at a percentage adjustment to the future test year budget for 2007 for each rate schedule, the percent change from the two Proofs of Revenue for each rate schedule (2006 Original filing, Attachment IV-C and 2006 Remand Settlement rates, Attachment IV-C Revision) was calculated for Distribution and Transmission. That percentage change was then applied to the future test year Budget Revenues in Exhibit Future 1, Schedule D-3 on page 2 (adjusted for Hurricane Isabel) to develop the revenues in Exhibit Future 1, Schedule D-3, on page 3. This calculation is shown in detail on page 2A of Exhibit Future 1, Schedule D-3 Revision, found in Attachment 1.

Q. Why is there an add-back of Hurricane Isabel revenues on Exhibit Future 1, Schedule D-3 Revision, page 2A?

A. When this case was filed on March 29, 2007, the Commission had already issued an order on remand relating to the disallowance of Hurricane Isabel costs. As a result, the Budgeted revenues found on page 2 of original Exhibit Future 1, Schedule D-3 reflected the reduction of Hurricane Isabel revenues; however, filed rates, prior to the Remand Settlement, do not. The new rates resulting from the Remand Settlement, effective on August 1, 2007, do reflect this disallowance. To properly adjust revenues from current rates, the Hurricane Isabel disallowance must be added back to arrive at revenues under current rates before adjusting to reflect the Remand Settlement rates.

Q. Are there any other adjustments being made to Exhibit Future 1, Schedule D-3, page 3?

A. Yes. Year-end customer counts and annualization revenues are being adjusted as explained in Mr. Woodruff's rebuttal testimony, Statement No. 4-R. This results in an increase in Distribution annualization revenues on Future 1 D-3, page 3, Line 27 column 5, from $1.7 million in the original filing to $2.9 million in this revision.

Q. Are these new present rate revenues used in any other exhibits being revised for this case?

A. Yes, these are the basis for Exhibit JMK 2A Revised, the revised cost allocation study being submitted by Mr. Kleha as part of his rebuttal testimony.

REVISIONS TO ALLOCATION OF THE REVENUE INCREASE

Q. Have the principles that PPL Electric followed in allocating the distribution rate increase for this revision changed?

A. No. As discussed by Mr. Krall, PPL Electric allocated the proposed revenue increase in this proceeding on the basis of cost of service and gradualism. In addition, as Mr. Krall explains, allocation of the proposed increase also reflects the Commonwealth Court's decision in the Lloyd case.

Q. Has the Company revised its proposed allocation of the distribution rate increase?

A. Yes, we have allocated the increase to reflect the effect of the new distribution rates approved in the Remand Settlement.

Q. How does the Company propose to allocate the distribution rate increase in this proceeding?

A. As described in more detail by Mr. Krall in his direct and rebuttal testimony, the increase has been allocated in a way that is designed to move each rate schedule one-half of the way to full cost of service as measured by indexed rate of return, with the constraint that no rate schedule would receive a distribution rate increase more than twice the system average distribution increase.

Q. Have you prepared a table to show the results of your proposed revenue allocation?

A. Yes. Appendix A-Revised included as Attachment 3 of this testimony provides the rate of return for each rate schedule at the adjusted present rates described previously and at proposed rates, and the movement toward cost of service on a relative rate of return basis. As shown on this table, with three exceptions, all rate schedules were moved one-half of the way to full cost of service. The three exceptions are Rate Schedules RTS, LP-6, and the Street Lighting rates. In each case these rates were so far below cost of service that they could not be moved half-way to cost of service without imposing very large rate increases, out of proportion to the overall rate increase requested in this proceeding. Although not shown on Appendix A, Street Lighting customers would require a 36.8 percent

distribution rate increase and Rate Schedule RTS customers would require a 108.24 percent distribution rate increase to achieve the 50 percent move to system average rate of return. The rate reduction for LP-6 in the Remand Settlement moved this class well below cost of service in this proceeding, and as a result the condition that no increase exceed twice the system average increase was applied.

Q. How is this revised allocation reflected in Exhibit Future 1, Schedule D-3?

A. The revised allocation or revenue change is found on page 6 of Exhibit Future 1, Schedule D-3, in column 13.

Q. Can you demonstrate the difference that resulted from the Remand Settlement, the revised revenue requirements, and this revised reallocation compared with the original filing?

A. Yes. Table 2 illustrates the effects:

Table 2

Revised Allocation of the Increase

Rate	Original Filing Increase Allocation	Revised Filing Increase Allocation	Change
RS	$ 76,779,736	$ 71,850,985	($4,928,751)
RTS	$ 982,822	$ 997,804	$14,982
RTD	$ 7,323	$ 25,685	$18,362
GS-1	$ 827,668	$ 164,698	($662,970)
GS-3	$ 370,602	$ (959,472)	($1,330,074)
LP-4	$ (195,962)	$ (347,707)	($151,745)
IS-P	$ (119,806)	$ (124,833)	($5,027)
LP-5	$ (131,416)	$ 7,996	$139,412
IS-T	$ 129,939	$ (85,958)	($215,897)
LP6	$ (7,547)	$ 9,810	$17,357

LPEP	$	(547)	$ (6,835)	($6,288)
ISA	$	0	$ -	$0
IS-1	$	383	$ (266)	($649)
BL	$	1,638	$ 526	($1,112)
SA	$	830,078	$ 890,207	$60,129
SM	$	221,362	$ 173,409	($47,953)
SHS	$	2,705,956	$ 2,886,936	$180,980
SE	$	341,190	$ 359,107	$17,917
TS	$	5,771	$ 5,507	($264)
SI-1	$	3,887	$ 3,834	($53)
GH-1	$	435,498	$ 440,214	$4,716
GH-2	$	101,138	$ 106,440	$5,302
Standby	$	3,730	$ (0)	($3,730)
Total	$	83,293,441	$ 76,398,087	($6,895,354)

Note that while the revised rate changes generally are different from the amounts originally proposed by the Company, they are measured off of a new base – the Remand Settlement rates and resulting test year revenues. As a result, the movement toward cost as measured on an indexed basis is greater than originally proposed.

For example, while the RS class is shown receiving a $4.9 million lower allocated increase, the distribution revenues at present rates increased approximately $10.6 million (see Table 1) due to the Remand Settlement. As a result, the RS class indexed return at proposed rates will move from 0.65 to 0.84.

Finally, as noted above, Street Lighting and Rate Schedule RTS are still limited by twice the system average increase proposed in the case, as is LP-6.

Tariff Rule 4 Changes

Q. PPLICA witness Stephen J. Baron challenges PPL Electric's proposed definition of distribution lines in Tariff Rule 4A, contending that it would eliminate the

Company's obligation to provide service to retail customers taking service at 69 kV and above. Do you agree?

A. No. In proposing this change, the Company is not intending to limit its basic obligation under the Public Utility Code to provide retail service to customers who take service at 69 kV and above. PPL Electric will continue to extend service facilities to these customers, will continue to deliver electricity to them and, if they do not elect to purchase supply from an Electric Generation Supplier, will continue to provide default service supply to them.

Q. Can you explain why the Company is proposing this change to Tariff Rule 4A?

A. PPL Electric is proposing this change for two reasons. First, this change will make the definition of a distribution line in Tariff Rule 4 consistent with the definition in existing Tariff Rule 3. The term "distribution system" is not defined in the current provisions of Tariff Rule 4. Tariff Rule 3 currently defines as follows: "The distribution system is defined, for the purposes of this rule, as including all lines energized at voltages less than the nominal 69,000 volts and excluding service extensions and lines energized at voltages of nominal 69,000 volts or higher." In order to maintain consistency between both rules, distribution service extensions are provided from all lines energized at voltages less than the nominal 69,000 volts. Second, this change will accurately reflect the Company's current Commission - approved practice of classifying all lines at voltages 69 kV and higher as transmission facilities and classifying all lines at voltages below 69 kV as distribution facilities.

Q. Mr. Baron contends that there is no legitimate justification for the proposed change. Do you agree?

A. No. As I indicated, one of the reasons for this change is to accurately reflect the Company's current practice regarding the classification of lines as either transmission or distribution. That practice was reviewed and approved by the Commission and has been followed by PPL Electric for almost ten years. Effective on January 1, 1997, the Electricity Generation Customer Choice and Competition Act restructured Pennsylvania law regarding retail electric service so that retail customers have the ability to choose their Electric Generation Supplier. The Act required, among other things, Electric Distribution Companies to file restructuring plans that addressed unbundled rates for generation, transmission, distribution and other services. PPL Electric's predecessor filed its restructuring plan in April 1997 and the PUC approved the plan in June 1998. In its order, the Commission noted that, under Federal Energy Regulatory Commission ("FERC") Order No. 888, there was a need to distinguish between facilities used for transmission and those used for distribution. To address that issue, the Commission accepted PPL Electric's proposed approach and found that "facilities operating at voltages of 69 kV and above are transmission facilities; and facilities operating at less than 69 kV are local distribution facilities." This finding is the primary justification for the proposed change to Tariff Rule 4A.

Q. How would you propose to address Mr. Baron's concerns that this change somehow reduces or eliminates PPL Electric's obligation to provide retail service to these customer?

A. As I stated previously, it is not the Company's intent to limit its obligations to provide service to customers taking service at voltages of 69 kV and above. However, to address Mr. Baron's concern, PPL Electric would be willing to add the following clarification to Tariff Rule 4A(2): "However, this definition does not affect the Company's obligations under the Public Utility Code, Commission regulations and Commission orders to provide safe, reliable and adequate retail electric service to customers taking service at voltages of 69 kV and above."

Q. If the Commission were to reject this proposed change, how would the Company be affected?

A. If the Commission simply rejected the proposed tariff change, but allowed the Company to continue its current practice of classifying transmission and distribution lines, the effect would be minimal. Tariff Rule 3 and Tariff Rule 4 would not be worded exactly the same, but PPL Electric's operations and financial record keeping would not be affected. However, if the Commission were to reject the proposed tariff change and, at the same time, reject PPL Electric's current practice of classifying transmission and distribution lines, the adverse impact on the Company could be significant. If the Commission rejects the Company's current approach to classification of line, PPL Electric would be forced to re-classify a

significant number of its transmission and distribution facilities. This would be an extremely time consuming task, as it is my understanding that available records would not provide this information. Such a reclassification also may have substantial jurisdictional ratemaking ramifications as additional rate-base would be allocated to the large (LP-5, LP-6, and IST) rate classes. For these reasons, Mr. Baron's proposal should be rejected. Moreover, were his recommendation to be adopted the Commission must also provide the Company the opportunity to re-file its rates to reflect this additional distribution cost of service.

Q. With regard to the Company's proposal to add the term "Institutional Complex" to Tariff Rule 4A(7), Mr. Baron states that the new term is not defined and recommends that it be defined. Do you agree?

A. Yes. To avoid confusion regarding the definition of "Institutional Complex" and to clarify the Company's intention, the Company proposes to delete the phrase "to an Institutional Complex" and add the following to the end of the rule: "For application of this rule, services to more than one building or facility located on the same property and owned by the same entity will be considered service to a single premise; each individual building or facility will not be considered a separate premise."

Q. Does this proposed addition reflect any change to PPL Electric's existing line extension policies?

A. No, it does not. This revisions simply reflects how the Company has applied the rule for many years.

Q. Does the proposed revision have any effect on how the Company provides service to an individual building or facility on a customer's property?

A. No. The revision deals only with service extensions to multiple buildings or facilities on a single property. Rules and practices for individual buildings and facilities are not affected.

Q. In Rule 4C(1)(B), why is there no reference to "wires" in "Poles and Guys" as being supplied when, in fact, PPL Electric supplies these facilities?

A. Rule 4C(1) states that, "The Company furnishes and installs all electric service line facilities extending from its distribution supply lines to the customer's point of delivery using normal construction for load conditions according to Company standards except as follows:" The "electric service line facilities" include wires, poles, and guys.

Q. In Rule 4C, PPL Electric has proposed to delete the terms "at or near the customer's property line" and "on his property".

A. PPL will add this language back into the proposed tariff in the compliance filing.

Rate Structure and Options

Time of Day Metering

Q. Mr. Richards appears to believe that PPL Electric is proposing to eliminate the Time-of-Day (TOD) metering and billing rate provisions for Rate Schedules GS-1, GS-3, LP-4, LP-5, LP-6, and GH-1(R) in Supplement No. 54 its Tariff - to Electric Pa. P.U.C. No. 201. Is this accurate?

A. No. PPL Electric will maintain the TOD pricing provisions in these Rate Schedules until the end of the rate cap period, consistent with the Restructuring Settlement effective January 1, 1999. PPL Electric is not proposing to eliminate the TOD rates; it simply is proposing to eliminate the additional charge of $14.95 per month for TOD metering in the future. PPL Electric proposed to delete the following sentence to eliminate additional TOD charges: *"Time-of-Day metering and billing is available on request for an additional charge of $14.95 per month for a minimum period of one year."* Other than the removal, of the quoted provision, all other language in the TOD provisions remain intact.

Q. Mr. Richards also seems to be recommending that TOD rates be re-opened to new applicants. Do you agree?

A. No. In the Restructuring Settlement, which became effective January 1, 1999, availability of the TOD rates was limited to new or existing customers of the Company, who did not have the opportunity to purchase capacity and energy from their choice of electric generation suppliers. All customers now have the opportunity to shop and, accordingly, the TOD rates are closed to new applicants.

Q. Do you believe the current TOD rates should remain closed to new applicants?

A Yes. The current TOD rates are economic development rates that were designed to assist new customers to locate and existing customers to remain and increase production in Pennsylvania. The rate decreased customer bills by reducing off-peak billing demands and reducing the on-peak billing period to 8 hours. Currently, the billing on-peak periods do not correspond to the PJM system on-peak periods, and the TOD rates will not reduce the PPL Electric and PJM system peak demands. Accordingly, it would not be appropriate to add more customers to these rates.

Q. Can PPL Electric's Time-of-Use Pricing Program extensions discussed by Mr. Krall provide an alternative to other TOD provisions in the tariff?

A. Yes. The Company is proposing to extend the Demand Side Initiative and Demand Side Response Riders to the end of the rate cap period. These market-based pricing structure programs are designed to increase customers' awareness of market price volatility. These programs will assist the customer in managing their costs in competitive markets that utilize demand response mechanisms. Both PPL Electric and PJM can benefit from this customer participation through reduced on-peak demands.

Data Availability

Q. In response to Mr. Richards, does PPL Electric plan to charge customers for load profile data access in the future?

A. Starting on page 5 line 17 and continuing through page 6 line 12 Mr. Richards discusses the need for customers to be aware of their usage patterns in order to "make informed shopping and demand side response decisions". The Company agrees with Mr. Richards on this point and with Mr. Richards' observation that helping to inform and educate customers is an important reason why the Company has undertaken the installation of an Advanced Metering Infrastructure. However, certain of Mr. Richards' assertions about that system and the data that will be available are not accurate. On page 5 line 20, Mr. Richards asserts that customers will have the ability to view histories of their usage on the basis of 15 minute intervals. PPL Electric's infrastructure does have the capability to collect and store data so that, when completed, all customers will be able to view two years of usage data on an hourly basis. However, the system, as currently configured, is not capable of collecting and storing 15 minute interval data for all of its customers. The Company does have a number of rates that require 15 minute interval data for the calculation of demand and the system does collect that data, however, the Company believes that the collection of hourly data for other customers is compatible with the evolving structure of electricity markets. For example, in its Competitive Bridge Plan filed at Docket No. P-00062227, the Commission approved rates for default generation service in 2010 that reflect cent per kWh charges, but no demand charges which might provide a rationale for the collection of 15 minute interval data. Further, the PJM Interconnection operates an energy market that reports prices on an hourly basis, not a quarter hour basis. As a consequence, while customers and, with the approval of the customers their

consultants, will be able to obtain hourly usage histories, those who desire data on a 15 minute basis will continue to pay a fee for the additional costs required to obtain data on a non-standard basis.

Q. Mr. Richards asserts that his firm is disadvantaged relative to larger, more sophisticated suppliers in being able to obtain 15 minute interval data. Do you agree?

A. No, I do not. In accordance with the Commission's rules on electronic data transfer, suppliers can obtain data that is consistent with the customer's billing parameters via Electronic Data Interchange protocols (or "EDI"). If a customer is on a rate that requires 15 minute interval data for the billing of its PPL Electric rate, then that data is also available to the customer's supplier. If monthly data is used for billing, then only monthly data is available. If any supplier desires 15 minute interval data for a customer where 15 minute interval data is not used for billing, then that supplier will be required to pay a fee for the additional costs required to obtain data on a non-standard basis. Furthermore, in such an instance, the data will be provided via a means other than EDI.

Q. Finally, Mr. Richards states that "this data should be made available to all supplier/marketers". *Do you agree?*

A. The Commission has established rules regarding the confidentiality of customer information and the Company believes that those rules are very important. The Company views each individual customer as the ultimate decision maker as to who

gets their data and who does not. Therefore, the Company would agree with Mr. Richards if he were to add the qualifier that the data be made available with the customers consent.

Rate Schedules GS-1 and GS-3

Q. What is the difference between a single phase service and a multi or poly phase service?

A. Single phase service, such as supply to a residential customer, requires only one transformer and a single overhead high voltage supply from the utility. A multi or poly phase (usually referred to as three phase) service requires at least two transformers and at least two high voltage supply lines from the utility.

Q. Why does PPL Electric propose to restrict Rate Schedule GS-1 to new single phase customers and Rate Schedule GS-3 to new polyphase customers?

A. PPL Electric is proposing this change because the costs to provide service to a single phase customer compared to a polyphase customer are different, and cost of service principles support the separation of these different services into different rate schedules. Single phase is less expensive, requiring a single transformer and usually a self-contained, single phase meter. Polyphase requires at least one additional transformer (usually two) and more expensive metering. Based on a three year weighted average of the cost of single and three phase installations, the Company has determined that three phase is about twice as costly as single phase to install.

However, this proposed change to the Tariff will be prospective only; existing customers are grandfathered on their present rate schedule. By restricting the prospective application of these rates to either single phase (Rate Schedule GS-1) or polyphase (Rate Schedule GS-3), over time, the cost to provide service under these rate schedules will align with the customers served.

Other utilities recognize there is a cost difference between single phase and polyphase service and charge accordingly. PECO, Met Ed, and Penelec all apply an additional customer charge for polyphase metering.

Q. Mr. Richards asserts that restricting future qualification for Rate Schedules GS-1 and GS-3 will affect customers' shopping options. Please comment.

A. A customer's decision whether to shop should not be determined by differences in distribution costs. The intention of restructuring was to establish rates that provided customers with the option to shop based upon competitive differences in energy costs. Allowing customers to save money by shifting back and forth from one rate schedule for POLR service to another schedule for service from an EGS because of distribution cost differences is not a proper way to encourage cost effective shopping for alternative energy sources.

Q. OSBA witness Knecht proposes that the Company advise customers on Rate Schedule GH-1 whether it would be beneficial to migrate to Rate Schedule GS-3. What is PPL Electric's position on this issue?

A. First, I would note that PPL Electric has proposed in this case that Rate Schedule GS-3 be limited to new customers with polyphase service. Only customers that meet this requirement should be permitted to transfer service from Rate Schedule GH-1 to Rate Schedule GS-3.

PPL Electric would be willing to prepare rate comparisons for all customers currently taking service on Rate Schedule GH-1 who qualify to take service Rate Schedule GS-3, to show the current rate differences based upon their prior year's usage. However, any such comparison should not include any recommendation regarding whether the customer should change rate schedules. This is the customer's choice, and PPL Electric would not want to be required to offer recommendations that subsequently might not be in the customer's best interest.

I note that OSBA has not quantified any lost revenue to PPL Electric from such rate schedule switches. PPL Electric estimates a $670,000 in distribution revenues if customers switched rates as shown below. This revenue loss should be reflected in the final revenue allowance in this case.

Customers moving from GH-1 TOD would not receive GS-3 TOD; TOD is now closed to new applicants. This results in greater kW billing units under GS-3 as shown below.

Table 4

Customer Changing Rates – GH-1 to GS-3
Estimated Revenue Reduction
Year Ending 12/31/2006

	Proposed GH-1	Proposed GS-3
Billing Units - kW	1,107,326	1,134,430
Proposed Distribution Rate - $/KW	$5.48/kW	$4.76/kW
Total Proposed Revenue	$6,068,147	$5,399,887

Estimated Revenue Loss		$(668,260)

Q. On page 18 of his testimony, Mr. Knecht expresses certain concerns about the impact of raising demand charges upon low load factor customers. Do you have any comment?

A. Yes. Initially, I note that load factor differences among rate classes is an important contributor to the differences in cost of service and rates between large and small customer classes. Mr. Knecht should not be surprised that when applying cost of service principles, differences in load factor will result in higher effective rates to serve lower load factor customers than to serve higher load factor customers within the same class as well. The recovery of a greater percentage of essentially fixed, non-variable costs through demand charges or the first block of customer charges is consistent with cost causation and should be approved.

Q. Should PPL Electric be required to prepare an analysis of demand diversity within the GS-1 rate class before reducing tail block distribution charges in future proceedings?

A. No. The Commission should not impose additional filing requirements on a single utility. This proceeding should not be used to define PPL Electric's burden of proof as to future rate cases. If OSBA, or any other party, believes information, such as class load diversity, is relevant to deciding an issue, that party can obtain such information through discovery and prepare its own analysis of what it believes is relevant data.

SE Rate Application

Q. The City of Scranton ("City") objects to PPL Electric's proposal to expand the availability of Rate SE to non-municipal customers. What is PPL Electric's reason for the proposed change?

A. PPL Electric proposed this change in order to give developers or private owners the opportunity for expanded choice in lighting facilities, while removing PPL Electric from the duties of operating or maintaining such facilities. There is increasing interest in different lighting equipment, including halogen, sodium, and Light Emitting Diodes (LEDs). Many of these systems hold promise for reducing energy usage. However, PPL Electric does not consider it to be cost effective for it to own and maintain all of the types of equipment that might be chosen, and wants to give developers/landowners the option to choose to own and maintain these facilities. This is consistent with service provided under all other rate schedules where the customer owns its electric wiring equipment and lighting fixtures.

Q. What is your understanding of the City's concern?

A. As I understand it, the City is concerned that developers would install these facilities along roads that are not dedicated to the municipality, and then would cease to maintain the facilities, or not construct them to proper standards. Then, the developer would walk away from the project, effectively forcing the City to take over and maintain these lighting systems.

Q. Is this a valid concern on the part of the City?

A. It is an understandable concern, but I believe one that can be handled by PPL Electric and the City without depriving developers of the opportunity to consider service under Rate SE.

Q. Please explain.

A. In discovery, the City confirmed that it has the power to dictate lighting requirements for new developments under its zoning and subdivision ordinances. As a result, the City can always deny subdivision approval for proposed lighting facilities that do not meet its standards. In addition, it is my understanding that municipal subdivision and zoning ordinances generally provide for bonding requirements to ensure that infrastructure facilities are constructed up to Code. The bond should cover the cost of lighting facilities installed at the developer's cost and to be owned by the developer.

However, PPL Electric recognizes that Rate SE, as currently drafted, does not include any requirement of municipal review of lighting plans, and it could be the case that an unscrupulous developer could install substandard facilities without either PPL Electric's or the City's consent. Therefore, PPL Electric proposes that Rate SE be revised to include the following additional language: "Any non-municipal customer will be required to demonstrate that it has complied with all municipal requirements pertaining to lighting before being eligible for Rate SE. In addition, the customer will be required to provide PPL Electric and the municipality with an inspector's certification that the street lighting facilities are constructed to applicable electrical code requirements before the facilities may be energized."

Residential Customer Charge and Block Rates

Q. Do you agree with OCA witness Mr. Galligan on his derivation of the customer charge?

A. No. Mr. Kleha discusses the Customer component in his rebuttal testimony. Based on Mr. Kleha's data, there is justification for a Customer charge as high as $24. Even considering only direct customer costs, Mr. Kleha demonstrates that a $13.49 charge is justified. The $10 that PPL Electric is requesting is a conservative movement in the customer charge.

Q. Do you have any comments on Mr. Galligan's approach to increasing the kWh steps of the Rate Schedule RS?

A. Yes. His method of a equal across the board increase to the kWh charges increases the dependence on kWh charges for the Company's Distribution function. PPL Electric's Distribution services are not driven by kWh throughput, but are predominately fixed costs. Mr. Galligan's approach increases revenue volatility to the Company's Distribution function due to weather conditions, conservation programs, and potential usage effects of high POLR energy costs in the future, which likely will give customers an incentive to reduce usage. However, reduced usage will not reduce the cost to operate the distribution system.

PPL Electric's proposed designs are moving in the direction supported by the cost of service while reducing dependency on the kWh throughput as a revenue driver.

Q. Does this complete your testimony?

A. Yes.

ATTACHMENT 1

PPL Electric Utilities Corporation
12 month Period Ended December 31, 2007 Budget

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line Number	Rate Schedule	Number of Customers	Sales (KWH)	Distribution Present Rate Revenue	USR (Universal Service Rider)	EER (Energy Efficiency Rider)	Transmission Present Rate Revenue	CTC Present Rate Revenue	ITC Present Rate Revenue	E&C Present Rate Revenue	Present Rate Revenue	State Tax Adjustment Surcharge (STAS) Distribution	State Tax Adjustment Surcharge (STAS) Other	Total Revenue
1	RS	1,193,652	13,782,976,000	$ 375,738,309	$ -	$ -	$ 77,976,133	$ 26,849,832	$ 131,640,768	$ 688,169,807	$ 1,300,376,849	$ (200,456)	$ 29,439	$ 1,300,205,832
2	RTS	14,157	385,602,000	$ 3,663,000	$ -	$ -	$ 2,183,290	$ 627,715	$ 3,074,619	$ 16,895,636	$ 26,464,260	$ (1,892)	$ 839	$ 26,463,207
3	RTD	289	5,013,000	$ 132,691	$ -	$ -	$ 26,378	$ 12,504	$ 61,202	$ 225,437	$ 460,212	$ (71)	$ 12	$ 460,153
4	GS-1	146,161	1,966,887,000	$ 75,415,309	$ -	$ -	$ 11,019,603	$ 4,864,555	$ 23,829,428	$ 121,161,809	$ 236,310,704	$ (38,394)	$ 4,048	$ 236,276,358
5	GS-3	22,521	6,734,385,000	$ 115,677,144	$ -	$ -	$ 49,129,868	$ 18,475,321	$ 90,353,603	$ 466,734,879	$ 740,371,015	$ (59,186)	$ 15,490	$ 740,327,319
6	LP-4	1,011	5,824,347,220	$ 30,263,941	$ -	$ -	$ 33,008,249	$ 9,546,644	$ 46,737,611	$ 271,683,756	$ 391,240,200	$ (15,600)	$ 8,756	$ 391,233,356
7	IS-P	28	350,179,965	$ 1,800,382	$ -	$ -	$ 1,962,576	$ 615,632	$ 3,006,678	$ 13,247,870	$ 20,633,338	$ (926)	$ 433	$ 20,632,843
8	LP-5	104	3,203,809,537	$ 1,615,397	$ -	$ -	$ 18,057,516	$ 5,325,890	$ 26,024,214	$ 136,217,290	$ 187,240,308	$ (881)	$ 4,335	$ 187,243,762
9	IS-T	25	2,028,985,247	$ 713,399	$ -	$ -	$ 11,309,318	$ 2,838,172	$ 13,877,496	$ 63,869,215	$ 92,607,600	$ (379)	$ 2,057	$ 92,609,278
10	LP-6	3	363,850,000	$ 139,000	$ -	$ -	$ 2,055,141	$ 1,157,228	$ 5,655,761	$ 16,119,588	$ 25,126,718	$ (71)	$ 604	$ 25,127,251
11	LPEP	1	72,000,000	$ 331,000	$ -	$ -	$ 406,884	$ 328,789	$ 1,609,563	$ 2,787,456	$ 5,463,692	$ (169)	$ 122	$ 5,463,645
12	ISA	1	264,373,863	$ 526,600	$ -	$ -	$ 1,491,906	$ 501,308	$ 2,460,059	$ 11,449,120	$ 16,428,993	$ (275)	$ 596	$ 16,429,314
13	IS-1	3	1,447,000	$ 31,691	$ -	$ -	$ 8,179	$ 11,504	$ 56,381	$ 39,574	$ 147,329	$ (16)	$ 3	$ 147,316
14	BL	46	6,468,000	$ 280,856	$ -	$ -	$ 36,556	$ 12,400	$ 60,788	$ 264,432	$ 655,032	$ (144)	$ 9	$ 654,897
15	SA	0	23,015,000	$ 3,386,787	$ -	$ -	$ 129,397	$ 55,265	$ 260,737	$ 1,024,286	$ 4,856,472	$ (1,731)	$ 37	$ 4,854,778
16	SM	104	5,733,000	$ 888,622	$ -	$ -	$ 32,236	$ 14,478	$ 68,261	$ 284,007	$ 1,287,604	$ (454)	$ 10	$ 1,287,160
17	SHS	1,163	48,806,000	$ 10,968,285	$ -	$ -	$ 274,327	$ 126,294	$ 596,495	$ 3,735,967	$ 15,701,368	$ (5,602)	$ 116	$ 15,695,882
18	SE	88	35,699,000	$ 1,396,986	$ -	$ -	$ 201,942	$ 9,298	$ 104,435	$ 181,415	$ 1,894,076	$ (723)	$ 14	$ 1,893,367
19	TS	9	334,000	$ 20,748	$ -	$ -	$ 1,889	$ 1,036	$ 4,899	$ 16,203	$ 44,775	$ (11)	$ 1	$ 44,765
20	SI-1	3	87,000	$ 14,572	$ -	$ -	$ 492	$ 389	$ 1,838	$ 5,340	$ 22,631	$ (7)	$ -	$ 22,624
21	GH-1	957	299,775,000	$ 5,743,944	$ -	$ -	$ 1,570,988	$ 1,323,507	$ 6,487,607	$ 13,312,104	$ 28,438,150	$ (2,931)	$ 566	$ 28,435,785
22	GH-2	2,481	64,845,000	$ 1,356,056	$ -	$ -	$ 383,742	$ 289,954	$ 1,418,549	$ 3,007,900	$ 6,436,201	$ (688)	$ 131	$ 6,435,644
23	Standby(LP5-S)	6	8,581,000	$ 45,000	$ -	$ -	$ 37,197	$ 51,223	$ 250,359	$ 712,050	$ 1,095,829	$ (23)	$ 27	$ 1,095,833
24	PRS	0	141,624,168	$ 421,281	$ -	$ -	$ (56,906)	$ -	$ -	$ 8,506,065	$ 8,870,440	$ -	$ -	$ 8,870,440
25	Rate Revenue	1,382,796	37,618,625,000	$ 630,591,000	$ -	$ -	$ 211,230,901	$ 73,039,138	$ 357,641,551	$ 1,839,671,206	$ 3,112,173,798	$ (330,632)	$ 67,645	$ 3,111,910,809
26														
27	Annualization Adjustment		0	0			0	0	0	0	$ -	$ -	$ -	$ -
28												$ -		
29	Total PUC Tariff Revenue		37,618,625,000	$ 630,591,000	$ -	$ -	$ 211,230,901	$ 73,039,138	$ 357,641,551	$ 1,839,671,206	$ 3,112,173,798	$ (330,632)	$ 67,645	$ 3,111,910,809
30														
31	Other Electric Revenues													
32	Late Payment			$ 9,262,000			$ -							$ 9,262,000
33	Misc. Revenue			$ 369,000			$ -							$ 369,000
34	Rent			$ 29,693,492			$ 903,303							$ 30,596,795
35	Other			$ 2,686,087			$ -	(a)						$ 2,686,087
36	Total Other			$ 42,010,579			$ 903,303					$ -	$ -	$ 42,913,882
37														
38	Total Operating Revenue		$ 37,618,625,000	$ 672,601,579			$ 212,134,204	$ 73,039,138	$ 357,641,551	$ 1,839,671,206	$ 3,112,173,798	$ (330,632)	$ 67,645	$ 3,154,824,691

(a): $149,005,912 was removed from Page 1. This revenue is received from PJM and is not related to charges for retail service.

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J.R. Schadt
O.G. Kaspar

PPL Electric Utilities Corporation
Remand Adjustments to Budget at Present Rates
12 month Period Ended December 31, 2007

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line Number	Rate Schedule	Number of Customers	Sales (KWH)	Huricane Isabel adjustment	Distribution Present Rate Revenue (page 2 col. 5)	Distribution Remand rate change.	Adjusted Distribution Revenues	Transmission Present Rate Revenue (page 2 col. 8)	Transmission Remand Rate change	Adjusted Trans mission Revenue
1	RS	1,193,652	13,782,978,000	$ 795,709	$ 375,738,309	2.61%	$ 386,343,017	$ 77,978,133	14.44%	$ 89,235,540
2	RTS	14,157	385,602,000	$ 22,000	$ 3,683,000	7.71%	$ 3,990,636	$ 2,183,290	14.44%	$ 2,498,483
3	RTD	269	5,013,000	$ 291	$ 132,691	2.82%	$ 136,735	$ 28,378	14.44%	$ 32,475
4	GS-1	146,161	1,968,887,000	$ 111,582	$ 75,415,309	-2.57%	$ 73,585,280	$ 11,019,603	5.75%	$ 11,653,749
5	GS-3	22,521	8,734,385,000	$ 120,967	$ 115,677,144	-5.22%	$ 109,752,651	$ 49,129,868	5.63%	$ 51,897,747
*6	LP-4	1,011	5,824,347,220	$ 29,000	$ 30,263,941	-4.80%	$ 28,838,237	$ 33,008,249	-12.57%	$ 28,857,948
*7	IS-P	28	350,179,965	$ 2,000	$ 1,800,382	-2.06%	$ 1,765,281	$ 1,962,576	-7.97%	$ 1,806,132
*8	LP-5	104	3,203,809,537	$ 1,000	$ 1,615,397	-34.10%	$ 1,065,194	$ 18,057,516	-26.01%	$ 13,360,616
*9	IS-T	25	2,028,985,247	$ -	$ 713,399	-24.52%	$ 538,503	$ 11,309,318	-35.26%	$ 7,321,987
10	LP-6	3	363,650,000	$ -	$ 139,000	-74.39%	$ 35,596	$ 2,055,141	-25.71%	$ 1,526,702
11	LPEP	1	72,000,000	$ 1,000	$ 331,000	0.34%	$ 333,125	$ 406,884	54.98%	$ 630,589
*12	ISA	1	264,373,863	$ -	$ 526,600	0.00%	$ 526,600	$ 1,491,906	-64.51%	$ 529,528
13	IS-1	3	1,447,000	$ -	$ 31,691	0.00%	$ 31,691	$ 8,179	5.63%	$ 8,639
14	BL	46	6,468,000	$ -	$ 280,856	0.00%	$ 280,856	$ 36,556	5.63%	$ 38,615
15	SA	0	23,015,000	$ 6,296	$ 3,386,787	4.95%	$ 3,561,159	$ 129,397	5.63%	$ 136,682
16	SM	104	5,733,000	$ 1,652	$ 888,622	4.88%	$ 933,723	$ 32,236	5.71%	$ 34,076
17	SHS	1,163	48,806,000	$ 20,390	$ 10,968,285	5.10%	$ 11,548,813	$ 274,327	5.72%	$ 290,009
18	SE	88	35,699,000	$ 2,597	$ 1,396,986	2.64%	$ 1,436,561	$ 201,942	5.63%	$ 213,319
19	TS	9	334,000	$ 39	$ 20,748	5.98%	$ 22,029	$ 1,889	5.62%	$ 1,995
20	SI-1	3	87,000	$ 27	$ 14,572	5.06%	$ 15,337	$ 492	5.79%	$ 520
21	GH-1	957	299,775,000	$ 7,281	$ 5,743,944	-9.06%	$ 5,230,227	$ 1,570,988	5.63%	$ 1,659,493
22	GH-2	2,481	64,845,000	$ 1,719	$ 1,356,056	-9.47%	$ 1,229,243	$ 363,742	5.63%	$ 384,235
23	Standby(LP5-S)	6	6,581,000	$ -	$ 45,000	-22.32%	$ 34,955	$ 37,197	-78.87%	$ 7,859
24	PRS		141,624,168		$ 421,281			$ (56,906)	$ -	$ -
25	**Rate Revenue**	**1,382,796**	**37,618,625,000**		**$ 630,591,000**		**$ 631,235,451**	**$ 211,230,901**		**$ 212,126,939**
26										

D3
Revision
Page 2A
O.G. Kasper

PPL Electric Utilities Corporation
12 month Period Ended December 31, 2007 Budget at Present Rates, Annualized

(1) Line Number	(2) Rate Schedule	(3) Number of Customers	(4) Sales (KWH)	(5) Distribution Present Rate Revenue	(6) USR (Universal Service Rider)	(7) EER (Energy Efficiency Rider)	(8) Transmission Present Rate Revenue	(9) CTC Present Rate Revenue	(10) ITC Present Rate Revenue	(11) E&C Present Rate Revenue	(12) Present Rate Revenue	(13) State Tax Adjustment Surcharge (STAS) Distribution -0.049%	(14) State Tax Adjustment Surcharge (STAS) Other 0.126%	(15) Total Revenue
1	RS	1,193,652	13,782,978,000	$ 386,343,017			$ 89,235,540	$ 26,849,832	$ 131,640,768	$ 688,169,807	$ 1,322,238,964	$ (195,629)	$ 1,179,229	$ 1,323,222,563
2	RTS	14,157	385,602,000	$ 3,990,636			$ 2,498,483	$ 627,715	$ 3,074,619	$ 16,895,636	$ 27,087,089	$ (1,955)	$ 29,102	$ 27,114,235
3	RTD	269	5,013,000	$ 136,735			$ 32,475	$ 12,504	$ 61,202	$ 225,437	$ 468,354	$ (67)	$ 418	$ 468,704
4	GS-1	146,161	1,968,687,000	$ 73,585,280			$ 11,653,749	$ 4,864,555	$ 23,829,428	$ 121,181,809	$ 235,114,821	$ (36,057)	$ 203,527	$ 235,282,292
5	GS-3	22,521	8,734,385,000	$ 109,752,651			$ 51,897,747	$ 18,475,321	$ 90,353,803	$ 466,734,879	$ 737,214,401	$ (53,779)	$ 790,602	$ 737,951,224
6	LP-4	1,011	5,824,347,220	$ 28,838,237			$ 28,857,948	$ 9,546,644	$ 46,737,611	$ 271,683,756	$ 385,664,196	$ (14,131)	$ 449,601	$ 386,099,666
7	IS-P	28	350,179,965	$ 1,765,281			$ 1,806,132	$ 615,832	$ 3,006,678	$ 13,247,870	$ 20,441,793	$ (865)	$ 23,532	$ 20,464,461
8	LP-5	104	3,203,809,537	$ 1,065,194			$ 13,360,616	$ 5,325,890	$ 26,024,214	$ 136,217,290	$ 181,993,204	$ (522)	$ 227,969	$ 182,220,651
9	IS-T	25	2,028,985,247	$ 538,503			$ 7,321,987	$ 2,838,172	$ 13,877,496	$ 63,869,215	$ 88,445,374	$ (264)	$ 110,763	$ 88,555,873
10	LP-6	3	363,650,000	$ 35,596			$ 1,526,702	$ 1,157,228	$ 5,655,761	$ 16,119,588	$ 24,494,875	$ (17)	$ 30,819	$ 24,525,676
11	LPEP	1	72,000,000	$ 333,125			$ 630,589	$ 328,789	$ 1,609,563	$ 2,787,456	$ 5,689,522	$ (163)	$ 6,749	$ 5,696,108
12	ISA	1	264,373,863	$ 526,600			$ 529,528	$ 501,308	$ 2,460,059	$ 11,449,120	$ 15,466,615	$ (258)	$ 18,824	$ 15,485,182
13	IS-1	3	1,447,000	$ 31,691			$ 8,639	$ 11,504	$ 56,381	$ 39,574	$ 147,789	$ (16)	$ 146	$ 147,920
14	BL	46	6,468,000	$ 280,856			$ 38,615	$ 12,400	$ 60,788	$ 264,432	$ 657,091	$ (138)	$ 474	$ 657,428
15	SA	0	23,015,000	$ 3,561,159			$ 136,682	$ 55,265	$ 260,737	$ 1,024,286	$ 5,038,129	$ (1,745)	$ 1,861	$ 5,038,245
16	SM	104	5,733,000	$ 933,723			$ 34,076	$ 14,478	$ 68,261	$ 284,007	$ 1,334,545	$ (458)	$ 505	$ 1,334,593
17	SHS	1,163	48,806,000	$ 11,548,813			$ 290,009	$ 126,294	$ 596,495	$ 3,735,967	$ 16,297,578	$ (5,659)	$ 5,983	$ 16,297,902
18	SE	88	35,699,000	$ 1,436,561			$ 213,319	$ 9,298	$ 104,435	$ 181,415	$ 1,945,028	$ (704)	$ 641	$ 1,944,965
19	TS	9	334,000	$ 22,029			$ 1,995	$ 1,036	$ 4,899	$ 16,203	$ 46,162	$ (11)	$ 30	$ 46,182
20	SI-1	3	87,000	$ 15,337			$ 520	$ 389	$ 1,838	$ 5,340	$ 23,425	$ (8)	$ 10	$ 23,427
21	GH-1	957	299,775,000	$ 5,230,227			$ 1,659,493	$ 1,323,507	$ 6,487,607	$ 13,312,104	$ 28,012,939	$ (2,563)	$ 28,706	$ 28,039,082
22	GH-2	2,481	64,845,000	$ 1,229,243			$ 384,235	$ 289,954	$ 1,418,549	$ 3,007,900	$ 6,329,881	$ (602)	$ 6,427	$ 6,335,705
23	Standby(LP5-S)	6	6,581,000	$ 34,955			$ 7,859	$ 51,223	$ 250,359	$ 712,050	$ 1,056,447	$ (17)	$ 1,287	$ 1,057,716
24	PRS		141,624,168	$ 421,281			$ (56,906)	$ -	$ -	$ 8,506,065	$ 8,870,440	$ (206)	$ 10,646	$ 8,880,879
25	Rate Revenue	1,382,796	37,618,625,000	$ 631,656,732	$ -	$ -	$ 212,070,034	$ 73,039,138	$ 357,641,551	$ 1,839,671,206	$ 3,114,078,661	$ (315,833)	$ 3,127,852	$ 3,116,890,680
26														
27	Annualization Adjustment		255,002,796	$ 2,916,897	$ -	$ -	$ 1,478,192	$ 432,439	$ 2,124,401	$ 10,875,885	$ 17,827,814	$ -	$ -	$ 17,827,814
28														
29	Total PUC Tariff Revenue		37,873,627,796	$ 634,573,629	$ -	$ -	$ 213,548,226	$ 73,471,577	$ 359,765,952	$ 1,850,547,091	$ 3,131,906,475	$ (315,833)	$ 3,127,852	$ 3,134,718,494
30														
31	Other Electric Revenues													
32	Late Payment			$ 9,262,000			$ -				$ 9,262,000			$ 9,262,000
33	Misc. Revenue			$ 369,000			$ -				$ 369,000			$ 369,000
34	Rent			$ 29,693,492			$ 903,303				$ 30,596,795			$ 30,596,795
35	Other			$ 2,686,087			$ -				$ 2,686,087			$ 2,686,087
36	Total Other			$ 42,010,579			$ 903,303	$ -	$ -	$ -	$ 42,913,882	$ -	$ -	$ 42,913,882
37														
38	Total Operating Revenue			$ 676,584,208			$ 214,451,529	$ 73,471,577	$ 359,765,952	$ 1,850,547,091	$ 3,174,820,358	$ (315,833)	$ 3,127,852	$ 3,177,632,376

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PPL Electric Utilities Corporation
12 month Period Ended December 31, 2007 Pro Forma Budget at Present Rates

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line Number	Rate Schedule	Distribution Present Rate Revenue	USR (Universal Service Rider)	EER (Energy Efficiency Rider)	Transmission Rate Revenue	CTCRate Revenue	ITC Rate Revenue	E&CRate Revenue	Present Rate Revenue	State Tax Adjustment Surcharge (STAS) Distribution -0.049%	State Tax Adjustment Surcharge (STAS) Other 0.126%	Total Revenue
		(Note 1)	(Note 2)		(Note 3)	(Note4)	(Note 5)	(Note 6)				
1	RS	$ 365,875,461	$ 20,467,556		$ 89,235,540	$ 26,849,832	$ 131,640,768	$ 688,169,807	$ 1,322,238,964	$ (195,629)	$ 1,179,229	$ 1,323,222,563
2	RTS	$ 3,795,919	$ 194,717		$ 2,498,483	$ 627,715	$ 3,074,619	$ 16,895,636	$ 27,087,089	$ (1,955)	$ 29,102	$ 27,114,235
3	RTD	$ 129,507	$ 7,228		$ 32,475	$ 12,504	$ 61,202	$ 225,437	$ 468,354	$ (67)	$ 418	$ 468,704
4	GS-1	$ 73,585,280	$ -		$ 11,653,749	$ 4,864,555	$ 23,829,428	$ 121,181,809	$ 235,114,821	$ (36,057)	$ 203,527	$ 235,282,292
5	GS-3	$ 109,752,651	$ -		$ 51,897,747	$ 18,475,321	$ 90,353,803	$ 466,734,879	$ 737,214,401	$ (53,779)	$ 790,602	$ 737,951,224
6	LP-4	$ 28,838,237	$ -		$ 28,857,948	$ 9,546,644	$ 46,737,611	$ 271,683,756	$ 385,664,196	$ (14,131)	$ 449,601	$ 386,099,666
7	IS-P	$ 1,765,281	$ -		$ 1,806,132	$ 615,832	$ 3,006,678	$ 13,247,870	$ 20,441,793	$ (865)	$ 23,532	$ 20,464,461
8	LP-5	$ 1,065,194	$ -		$ 13,360,616	$ 5,325,690	$ 26,024,214	$ 136,217,290	$ 181,993,204	$ (522)	$ 227,969	$ 182,220,651
9	IS-T	$ 538,503	$ -		$ 7,321,987	$ 2,838,172	$ 13,877,496	$ 63,869,215	$ 88,445,374	$ (264)	$ 110,763	$ 88,555,873
10	LP-6	$ 35,596	$ -		$ 1,526,702	$ 1,157,228	$ 5,655,761	$ 16,119,588	$ 24,494,875	$ (17)	$ 30,819	$ 24,525,676
11	LPEP	$ 333,125	$ -		$ 630,589	$ 328,789	$ 1,609,563	$ 2,787,456	$ 5,689,522	$ (163)	$ 6,749	$ 5,696,108
12	ISA	$ 526,600	$ -		$ 529,528	$ 501,308	$ 2,460,059	$ 11,449,120	$ 15,466,615	$ (258)	$ 18,824	$ 15,485,182
13	IS-1	$ 31,691	$ -		$ 8,639	$ 11,504	$ 56,381	$ 39,574	$ 147,789	$ (16)	$ 146	$ 147,920
14	BL	$ 280,856	$ -		$ 38,615	$ 12,400	$ 60,788	$ 264,432	$ 657,091	$ (138)	$ 474	$ 657,428
15	SA	$ 3,561,159	$ -		$ 136,682	$ 55,265	$ 260,737	$ 1,024,286	$ 5,038,129	$ (1,745)	$ 1,861	$ 5,038,245
16	SM	$ 933,723	$ -		$ 34,076	$ 14,478	$ 68,261	$ 284,007	$ 1,334,545	$ (458)	$ 505	$ 1,334,593
17	SHS	$ 11,548,813	$ -		$ 290,009	$ 126,294	$ 596,495	$ 3,735,967	$ 16,297,578	$ (5,659)	$ 5,983	$ 16,297,902
18	SE	$ 1,436,561	$ -		$ 213,319	$ 9,298	$ 104,435	$ 181,415	$ 1,945,028	$ (704)	$ 641	$ 1,944,965
19	TS	$ 22,029	$ -		$ 1,995	$ 1,036	$ 4,899	$ 16,203	$ 46,162	$ (11)	$ 30	$ 46,182
20	SI-1	$ 15,337	$ -		$ 520	$ 389	$ 1,838	$ 5,340	$ 23,425	$ (8)	$ 10	$ 23,427
21	GH-1	$ 5,230,227	$ -		$ 1,659,493	$ 1,323,507	$ 6,487,607	$ 13,312,104	$ 28,012,939	$ (2,563)	$ 28,706	$ 28,039,082
22	GH-2	$ 1,229,243	$ -		$ 384,235	$ 289,954	$ 1,418,549	$ 3,007,900	$ 6,329,881	$ (602)	$ 6,427	$ 6,335,705
23	Standby(LP5-S)	$ 34,955	$ -		$ 7,659	$ 51,223	$ 250,359	$ 712,050	$ 1,056,447	$ (17)	$ 1,287	$ 1,057,716
24	PRS	$ 421,281	$ -		$ (56,906)	$ -	$ -	$ 8,506,065	$ 8,870,440	$ (206)	$ 10,646	$ 8,880,879
25	Rate Revenue	$ 610,987,231	$ 20,669,501	$ -	$ 212,070,034	$ 73,039,138	$ 357,641,551	$ 1,839,671,206	$ 3,114,078,661	$ (315,833)	$ 3,127,852	$ 3,116,890,680
26												
27	Annualization Adjustment	$ 2,916,897			$ 1,478,192	$ 432,439	$ 2,124,401	$ 10,875,885	$ 17,827,814	$ -	$ -	$ 17,827,814
28												
29	Total PUC Tariff Revenue	$ 613,904,128	$ 20,669,501	$ -	$ 213,548,226	$ 73,471,577	$ 359,765,952	$ 1,850,547,091	$ 3,131,906,475	$ (315,833)	$ 3,127,852	$ 3,134,718,494
30												
31	Other Electric Revenues											
32	Late Payment	$ 9,262,000			$ -				$ 9,262,000			$ 9,262,000
33	Misc. Revenue	$ 369,000			$ -				$ 369,000			$ 369,000
34	Rent	$ 29,693,492			$ 903,303				$ 30,596,795			$ 30,596,795
35	Other	$ 2,686,087			$ -				$ 2,686,087			$ 2,686,087
36	Total Other	$ 42,010,579	$ -	$ -	$ 903,303				$ 42,913,882	$ -	$ -	$ 42,913,882
37												
38	Total Operating Revenue	$ 655,914,707	$ 20,669,501	$ -	$ 214,451,529	$ 73,471,577	$ 359,765,952	$ 1,850,547,091	$ 3,174,820,358	$ (315,833)	$ 3,127,852	$ 3,177,632,376

Note 1: Col 5, page 3- Column 4 and Column5
Note 2: USR Current Budget
Note 3: Col 8, page 3
Note 4: Col 9, page 3
Note 5: Col 10, page 3
Note 6: Col 11, page 3

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PPL Electric Utilities Corporation
12 month Period Ended December 31, 2007 Pro Forma Budget at Present Rates, Without Shopping

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Line Number	Rate Schedule	Distribution Present Rate Revenue	USR (Universal Service Rider)	EER (Energy Efficiency Rider)	Transmission Rate Revenue	CTC Rate Revenue	ITC Rate Revenue	E&C Rate Revenue	Present Rate Revenue	State Tax Adjustment Surcharge (STAS) -0.049% Distribution	State Tax Adjustment Surcharge (STAS) 0.126% Other	Total Revenue	Shopping Factor
		(Note 1)	(Note 2)		(Note 3)	(Note 4)	(Note 5)	(Note 6)					(Note 7)
1	RS	$ 365,875,461	$ 20,467,556	$ -	$ 89,235,540	$ 26,849,832	$ 131,640,768	$ 688,169,807	$ 1,322,238,964	$ (195,629)	$ 1,179,229	$ 1,323,222,563	0.000%
2	RTS	$ 3,795,919	$ 194,717	$ -	$ 2,498,483	$ 627,715	$ 3,074,619	$ 16,895,638	$ 27,087,089	$ (1,955)	$ 29,102	$ 27,114,235	0.000%
3	RTD	$ 129,507	$ 7,228	$ -	$ 32,475	$ 12,504	$ 61,202	$ 225,437	$ 468,354	$ (67)	$ 418	$ 468,704	0.000%
4	GS-1	$ 73,585,280	$ -	$ -	$ 11,653,749	$ 4,864,555	$ 23,829,428	$ 121,181,809	$ 235,114,821	$ (36,057)	$ 203,527	$ 235,282,292	0.000%
5	GS-3	$ 109,752,651	$ -	$ -	$ 51,908,128	$ 18,475,321	$ 90,353,803	$ 466,828,245	$ 737,318,148	$ (53,779)	$ 790,733	$ 738,055,102	0.020%
6	LP-4	$ 28,838,237	$ -	$ -	$ 28,881,053	$ 9,546,644	$ 46,737,611	$ 271,901,277	$ 385,904,822	$ (14,131)	$ 449,904	$ 386,340,595	0.080%
7	IS-P	$ 1,765,281	$ -	$ -	$ 1,806,132	$ 615,832	$ 3,006,878	$ 13,247,870	$ 20,441,793	$ (865)	$ 23,532	$ 20,464,461	0.000%
8	LP-5	$ 1,065,194	$ -	$ -	$ 13,383,368	$ 5,325,890	$ 26,024,214	$ 136,449,254	$ 182,247,920	$ (522)	$ 228,290	$ 182,475,688	0.170%
9	IS-T	$ 538,503	$ -	$ -	$ 7,330,784	$ 2,836,172	$ 13,877,496	$ 63,945,950	$ 88,530,906	$ (264)	$ 110,870	$ 88,641,513	0.120%
10	LP-6	$ 35,596	$ -	$ -	$ 1,526,702	$ 1,157,228	$ 5,655,761	$ 16,119,588	$ 24,494,875	$ (17)	$ 30,819	$ 24,525,678	0.000%
11	LPEP	$ 333,125	$ -	$ -	$ 630,589	$ 328,789	$ 1,609,563	$ 2,787,456	$ 5,689,522	$ (163)	$ 6,749	$ 5,696,108	0.000%
12	ISA	$ 526,600	$ -	$ -	$ 529,528	$ 501,308	$ 2,460,059	$ 11,449,120	$ 15,466,815	$ (258)	$ 18,824	$ 15,485,182	0.000%
13	IS-1	$ 31,691	$ -	$ -	$ 8,639	$ 11,504	$ 56,381	$ 39,574	$ 147,789	$ (16)	$ 146	$ 147,920	0.000%
14	BL	$ 280,856	$ -	$ -	$ 38,615	$ 12,400	$ 60,788	$ 264,432	$ 657,091	$ (138)	$ 474	$ 657,428	0.000%
15	SA	$ 3,561,159	$ -	$ -	$ 136,882	$ 55,265	$ 260,737	$ 1,024,286	$ 5,038,129	$ (1,745)	$ 1,861	$ 5,038,245	0.000%
16	SM	$ 933,723	$ -	$ -	$ 34,078	$ 14,478	$ 68,261	$ 284,007	$ 1,334,545	$ (458)	$ 505	$ 1,334,593	0.000%
17	SHS	$ 11,548,813	$ -	$ -	$ 290,009	$ 126,294	$ 596,495	$ 3,735,967	$ 16,297,578	$ (5,659)	$ 5,983	$ 16,297,902	0.000%
18	SE	$ 1,436,561	$ -	$ -	$ 213,319	$ 9,298	$ 104,435	$ 181,415	$ 1,945,028	$ (704)	$ 641	$ 1,944,965	0.000%
19	TS	$ 22,029	$ -	$ -	$ 1,995	$ 1,036	$ 4,899	$ 16,203	$ 46,162	$ (11)	$ 30	$ 46,182	0.000%
20	SI-1	$ 15,337	$ -	$ -	$ 520	$ 389	$ 1,838	$ 5,340	$ 23,425	$ (8)	$ 10	$ 23,427	0.000%
21	GH-1	$ 5,230,227	$ -	$ -	$ 1,659,493	$ 1,323,507	$ 6,487,607	$ 13,312,104	$ 28,012,939	$ (2,563)	$ 28,706	$ 28,039,082	0.000%
22	GH-2	$ 1,229,243	$ -	$ -	$ 384,235	$ 289,954	$ 1,418,549	$ 3,007,900	$ 6,329,881	$ (602)	$ 6,427	$ 6,335,705	0.000%
23	Standby(LPS-S)	$ 34,955	$ -	$ -	$ 7,859	$ 51,223	$ 250,359	$ 712,050	$ 1,056,447	$ (17)	$ 1,287	$ 1,057,718	0.000%
24	PRS	$ 421,281	$ -	$ -	$ (56,906)	$ -	$ -	$ 8,506,065	$ 8,870,440	$ (206)	$ 10,646	$ 8,880,879	
25	Rate Revenue	$ 610,987,231	$ 20,669,501	$ -	$ 212,135,069	$ 73,039,138	$ 357,641,551	$ 1,840,290,792	$ 3,114,763,281	$ (315,833)	$ 3,128,714	$ 3,117,576,163	
26													
$ 27	Annualization Adjustment	$ 2,916,897			$ 1,478,769	$ 432,439	$ 2,124,401	$ 10,879,523	$ 17,832,029	$ (1,429)	$ 18,793	$ 17,849,393	
28													
29	Total PUC Tariff Revenue	$ 613,904,128	$ 20,669,501	$ -	$ 213,613,838	$ 73,471,577	$ 359,765,952	$ 1,851,170,315	$ 3,132,595,311	$ (317,262)	$ 3,147,507	$ 3,135,425,556	
30													
31	Other Electric Revenues												
32	Late Payment	$ 9,262,000			$ -				$ 9,262,000			$ 9,262,000	
33	Misc. Revenue	$ 369,000			$ -				$ 369,000			$ 369,000	
34	Rent	$ 29,693,492			$ 903,303				$ 30,596,795			$ 30,596,795	
35	Other	$ 2,686,087			$ -				$ 2,686,087			$ 2,686,087	
36	Total Other	$ 42,010,579			$ 903,303	$ -	$ -	$ -	$ 42,913,882	$ -	$ -	$ 42,913,882	
37													
38	Total Operating Revenue	$ 655,914,707			$ 214,517,141	$ 73,471,577	$ 359,765,952	$ 1,851,170,315	$ 3,175,509,193	$ (317,262)	$ 3,147,507	$ 3,178,339,438	

Note 1: Col 3, page 4
Note 2: Col 4, page 4
Note 3: Col 6, page 4 / (1-Col 14)
Note 4: Col 7, page 4
Note 5: Col 8, page 4
Note 6: Col 9, page 4 / (1-Col 14)
Note 7: Percent customer shopping usage.

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PPL Electric Utilities Corporation
12 month Period Ended December 31, 2007 Proforma Budget at Proposed Rates, Without Shopping

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Line Number	Rate Schedule	Proposed Distribution Rate Revenue	USR (Universal Service Rider)	EER (Energy Efficiency Rider)	Transmission Rate Revenue	CTC Rate Revenue	ITCRate Revenue	E&CRate Revenue	Total Proposed Rate Revenue		State Tax Adjustment Surcharge (STAS) Distribution -0.049%	State Tax Adjustment Surcharge (STAS) Other 0.126%	Total Revenue	Total Revenue $ Change	Total Revenue % Change
			(Note 1)	(Note 2)	(Note 3)	(Note4)	(Note 5)	(Note 6)						(Note 7)	(Note 8)
1	RS	$ 428,241,490	$ 27,619,248	$ 2,382,188	$ 89,235,540	$ 26,849,832	$ 131,840,788	$ 668,169,607	$ 1,394,118,848	$ 1,394,118,848	$ (224,529)	$ 1,179,229	$ 1,395,073,548	$ 71,850,985	5.43%
2	RTS	$ 4,898,929	$ 267,000	$ 23,000	$ 2,498,483	$ 627,715	$ 3,074,619	$ 16,895,636	$ 28,085,382	$ 28,085,382	$ (2,445)	$ 29,102	$ 28,112,039	$ 997,804	3.68%
3	RTD	$ 151,844	$ 9,754	$ 834	$ 32,475	$ 12,504	$ 61,202	$ 225,437	$ 494,051	$ 494,051	$ (80)	$ 418	$ 494,389	$ 25,685	5.48%
4	GS-1	$ 73,279,059	$ -	$ 471,000	$ 11,653,749	$ 4,864,555	$ 23,829,428	$ 121,181,809	$ 235,279,600	$ 235,279,600	$ (36,138)	$ 203,527	$ 235,446,990	$ 164,898	0.07%
5	GS-3	$ 108,762,709	$ -		$ 51,908,128	$ 18,475,321	$ 90,353,803	$ 466,828,245	$ 736,358,206	$ 736,358,206	$ (53,308)	$ 790,733	$ 737,095,630	$ (959,472)	-0.13%
6	LP-4	$ 28,490,359	$ -		$ 28,881,053	$ 9,548,644	$ 46,737,811	$ 271,901,277	$ 385,556,944	$ 385,556,944	$ (13,980)	$ 449,004	$ 385,992,868	$ (347,707)	-0.09%
7	LP-P	$ 1,640,367	$ -		$ 1,808,132	$ 615,832	$ 3,006,676	$ 13,247,870	$ 20,318,899	$ 20,318,899	$ (804)	$ 23,532	$ 20,339,626	$ (124,833)	-0.61%
8	LP-5	$ 1,065,194	$ -		$ 13,383,368	$ 5,325,690	$ 26,024,214	$ 136,449,254	$ 182,247,920	$ 182,247,920	$ (522)	$ 228,290	$ 182,475,688	$ -	0.00%
9	LP-T	$ 449,818	$ -		$ 7,330,784	$ 2,838,172	$ 13,877,496	$ 63,945,950	$ 88,442,221	$ 88,442,221	$ (220)	$ 110,670	$ 88,552,671	$ (88,642)	-0.10%
10	LP-6	$ 45,411	$ -		$ 1,526,702	$ 1,157,228	$ 5,655,761	$ 16,119,588	$ 24,504,690	$ 24,504,690	$ (22)	$ 30,810	$ 24,535,486	$ 9,810	0.04%
11	LPEP	$ 326,287	$ -		$ 830,589	$ 328,789	$ 1,609,583	$ 2,787,456	$ 5,882,684	$ 5,882,684	$ (180)	$ 8,749	$ 5,889,273	$ (6,835)	-0.12%
12	ISA	$ 526,600	$ -		$ 529,528	$ 501,308	$ 2,460,059	$ 11,449,120	$ 15,466,615	$ 15,466,615	$ (258)	$ 18,824	$ 15,485,182	$ -	0.00%
13	IS-1	$ 31,425	$ -		$ 8,639	$ 11,504	$ 56,381	$ 39,574	$ 147,523	$ 147,523	$ (15)	$ 146	$ 147,654	$ (268)	-0.18%
14	BL	$ 281,383	$ -		$ 38,615	$ 12,400	$ 60,788	$ 264,432	$ 657,618	$ 657,618	$ (138)	$ 474	$ 657,954	$ 526	0.08%
15	SA	$ 4,451,802	$ -		$ 136,682	$ 55,265	$ 269,737	$ 1,024,286	$ 5,928,772	$ 5,928,772	$ (2,181)	$ 1,881	$ 5,928,452	$ 890,207	17.67%
16	SM	$ 1,107,217	$ -		$ 34,076	$ 14,478	$ 68,261	$ 284,007	$ 1,508,040	$ 1,508,040	$ (543)	$ 505	$ 1,508,002	$ 173,409	12.99%
17	SHS	$ 14,437,164	$ -		$ 290,009	$ 126,294	$ 596,495	$ 3,735,967	$ 19,185,929	$ 19,185,929	$ (7,074)	$ 5,983	$ 19,184,838	$ 2,686,936	17.71%
18	SE	$ 1,795,644	$ -		$ 213,319	$ 9,268	$ 104,435	$ 181,415	$ 2,304,311	$ 2,304,311	$ (880)	$ 641	$ 2,304,072	$ 359,107	18.46%
19	TS	$ 27,539	$ -		$ 1,995	$ 1,036	$ 4,899	$ 16,203	$ 51,672	$ 51,672	$ (13)	$ 30	$ 51,689	$ 5,507	11.92%
20	SI-1	$ 19,173	$ -		$ 520	$ 389	$ 1,838	$ 5,340	$ 27,260	$ 27,260	$ (9)	$ 10	$ 27,261	$ 3,834	16.36%
21	GH-1	$ 5,670,657	$ -		$ 1,659,493	$ 1,323,507	$ 6,487,607	$ 13,312,104	$ 28,453,368	$ 28,453,368	$ (2,779)	$ 5,706	$ 28,479,296	$ 440,214	1.57%
22	GH-2	$ 1,335,735	$ -		$ 384,235	$ 289,954	$ 1,418,549	$ 3,007,900	$ 6,436,373	$ 6,436,373	$ (655)	$ 6,427	$ 6,442,145	$ 106,440	1.68%
23	Standby(LP5-S)	$ 34,955	$ -		$ 7,859	$ 51,223	$ 250,359	$ 712,050	$ 1,056,446	$ 1,056,446	$ (17)	$ 1,267	$ 1,057,716	$ -	0.00%
24	PRS	$ 421,281	$ -	$ -	$ (56,906)	$ -	$ -	$ 8,506,065	$ 8,870,440		$ (206)	$ 10,648	$ 8,880,879	$ -	0.00%
25	Rate Revenue	$ 677,322,263	$ 27,896,000	$ 2,857,000	$ 212,135,069	$ 73,039,138	$ 357,841,551	$ 1,840,290,792	$ 3,191,181,812		$ (346,957)	$ 3,128,714	$ 3,193,963,570	$ 76,387,407	2.45%
26															
27	Annualization Adjustment	$ 3,283,369			$ 1,478,769	$ 432,439	$ 2,124,491	$ 10,879,523	$ 18,178,581		$ (1,599)	$ 18,783	$ 18,195,665	$ 346,302	
28															
29	Total PUC Tariff Revenue	$ 680,585,632	$ 27,896,000	$ 2,857,000	$ 213,613,838	$ 73,471,577	$ 359,765,952	$ 1,851,170,315	$ 3,209,360,314		$ (348,556)	$ 3,147,507	$ 3,212,159,265	$ 76,733,709	2.45%
30															
31	Other Electric Revenues														
32	Late Payment	$ 9,507,443			$ -				$ 9,507,443				$ 9,507,443	$ 245,443	2.65%
33	Misc. Revenue	$ 369,000			$ -				$ 369,000				$ 369,000	$ -	0.00%
34	Rent	$ 29,893,492			$ 903,303				$ 30,796,795				$ 30,796,795	$ -	0.00%
35	Other	$ 2,686,087							$ 2,686,087				$ 2,686,087	$ -	0.00%
36	Total Other	$ 42,256,022			$ 903,303	$ -	$ -	$ -	$ 43,159,325		$ -	$ -	$ 43,159,325	$ 245,443	0.57%
37															
38	Total Operating Revenue	$ 722,841,654			$ 214,517,141	$ 73,471,577	$ 359,765,952	$ 1,851,170,315	$ 3,252,519,639		$ (348,556)	$ 3,147,507	$ 3,255,318,590	$ 76,979,152	2.42%

Note 1: USR As Proposed with GRT
Note 2: EER As Proposed with GRT
Note 3: Col 6, page 5
Note 4: Col 7, page 4
Note 5: Col 8, page 4
Note 6: Col 9, page 5
Note 7: Col 13 - Col 13, page 5
Note 8: Col 14 / Col 13, page 5 (%)
Note 9: Percent customer shopping usage.

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Revision
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O.G. Kasper

ATTACHMENT 2

Rate Schedule RS
Residential Service
Calculation of Effect of Proposed Rate vs. Current Tariff
Based on bill frequency distribution for 12 months ended December 2006

PRESENT RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	13,307,098,330	$0.00650	$86,496,139
Distribution			
Total Bills	14,082,483	$7.96	$112,096,565
First 200 KWH	2,668,989,214	$0.02265	$60,452,606
Next 600 KWH	5,714,018,120	$0.02048	$117,023,091
Excess KWH	4,924,090,996	$0.01924	$94,739,511
Subtotal	13,307,098,330		$384,311,773
Energy & Capacity			
First 200 KWH	2,668,989,214	$0.05728	$152,879,702
Next 600 KWH	5,714,018,120	$0.05034	$287,643,672
Excess KWH	4,924,090,996	$0.04618	$227,394,522
Subtotal	13,307,098,330		$667,917,896
Competitive Transition Charge			
First 200 KWH	2,668,989,214	$0.00237	$6,325,504
Next 600 KWH	5,714,018,120	$0.00210	$11,999,438
Excess KWH	4,924,090,996	$0.00194	$9,552,737
Subtotal	13,307,098,330		$27,877,679
Intangible Transition Charge			
First 200 KWH	2,668,989,214	$0.01101	$29,385,571
Next 600 KWH	5,714,018,120	$0.00976	$55,768,817
Excess KWH	4,924,090,996	$0.00901	$44,366,060
Subtotal	13,307,098,330		$129,520,448
RWO			$76,718
RWI			$155,353
Total Rate Revenue			$1,296,356,006

PROPOSED RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	13,307,098,330	$0.00650	$86,496,139
Distribution			
Total Bills	14,082,483	$10.00	$140,824,830
First 200 KWH	2,668,989,214	$0.03058	$81,617,690
Next 600 KWH	5,714,018,120	$0.02540	$145,136,060
Excess KWH	4,924,090,996	$0.01770	$87,156,411
Subtotal	13,307,098,330		$454,734,991
Energy & Capacity			
First 200 KWH	2,668,989,214	$0.05728	$152,879,702
Next 600 KWH	5,714,018,120	$0.05034	$287,643,672
Excess KWH	4,924,090,996	$0.04618	$227,394,522
Subtotal	13,307,098,330		$667,917,896
Competitive Transition Charge			
First 200 KWH	2,668,989,214	$0.00237	$6,325,504
Next 600 KWH	5,714,018,120	$0.00210	$11,999,438
Excess KWH	4,924,090,996	$0.00194	$9,552,737
Subtotal	13,307,098,330		$27,877,679
Intangible Transition Charge			
First 200 KWH	2,668,989,214	$0.01101	$29,385,571
Next 600 KWH	5,714,018,120	$0.00976	$55,768,817
Excess KWH	4,924,090,996	$0.00901	$44,366,060
Subtotal	13,307,098,330		$129,520,448
RWO			$68,265
RWI			$152,261
Total Rate Revenue			$1,366,767,679

Summary of Total Revenues	
Total from bill distributions Proposed Rates	$1,366,767,679
Total from bill distributions Present Rates	$1,296,356,006
Rate Change Amount	$70,411,673
Percent	5.43%
2006 Rate revenue under Present Rates	$1,274,369,059
Rate Change Percent	5.43%
Amount	$69,198,240
2006 Projected Revenue under Proposed Rates	$1,343,567,299
2007 Rate revenue under Present Rates	$1,323,222,563
Rate Change Percent	5.43%
Amount	$71,850,985
2007 Projected Revenue under Proposed Rates	$1,395,073,548

PPL Electric Utilities Corporation
Rate Schedule RS with Off-Peak Water Heating-Separate Meter (RWO)
Residential Service
Calculation of Effect of Proposed Rate vs. Current Tariff
Based on bill frequency distribution for 12 months ended December 2006

PRESENT RATE	Units	Rate	Rate Revenue
Transmission			
Transmission - All KWH	696,379	$0.00650	$4,526
Distribution			
Total Bills	2,835	$15.45	$43,801
All KWH	696,379	$0.01855	$12,918
Subtotal	696,379		$56,719
Energy & Capacity			
All KWH	696,379	$0.00965	$6,720
Competitive Transition Charge			
All KWH	696,379	$0.00213	$1,483
Intangible Transition Charge			
All KWH	696,379	$0.01044	$7,270
Total Rate Revenue			$76,718

PROPOSED RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	696,379	$0.00650	$4,526
Distribution			
Total Bills	2,835	$10.00	$28,350
First 200 KWH	460,539	$0.03058	$14,083
Next 600 KWH	215,341	$0.02540	$5,470
Excess KWH	20,499	$0.01770	$363
Subtotal	696,379		$48,266
Energy & Capacity			
All KWH	696,379	$0.00965	$6,720
Competitive Transition Charge			
All KWH	696,379	$0.00213	$1,483
Intangible Transition Charge			
All KWH	696,379	$0.01044	$7,270
Total Rate Revenue			$68,265

PPL Electric Utilities Corporation
Rate Schedule RS with Off-Peak Water Heating-Single Meter (RW1)
Residential Service
Calculation of Effect of Proposed Rate vs. Current Tariff
Based on bill frequency distribution for 12 months ended December 2006

PRESENT RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	1,721,533	$0.00650	$11,190
Distribution			
Total Bills	1,161	$15.45	$17,937
First 200 KWH	229,648	$0.02265	$5,202
Next 400 KWH	437,638	$0.02048	$8,963
Next 600 KWH	504,228	$0.02048	$10,327
Excess KWH	550019	$0.01924	$10,582
Subtotal	1,721,533		$53,011
Energy & Capacity			
First 200 KWH	229,648	$0.05728	$13,154
Next 400 KWH	437,638	$0.01517	$6,639
Next 600 KWH	504,228	$0.05034	$25,383
Excess KWH	550,019	$0.04618	$25,400
Subtotal	1,721,533		$70,576
Competitive Transition Charge			
First 200 KWH	229,648	$0.00237	$544
Next 400 KWH	437,638	$0.00213	$932
Next 600 KWH	504,228	$0.00210	$1,059
Excess KWH	550,019	$0.00194	$1,067
Subtotal	1,721,533		$3,602
Intangible Transition Charge			
First 200 KWH	229,648	$0.01101	$2,528
Next 400 KWH	437,638	$0.01044	$4,569
Next 600 KWH	504,228	$0.00976	$4,921
Excess KWH	550,019	$0.00901	$4,956
Subtotal	1,721,533		$16,974
Total Rate Revenue			$155,353

PROPOSED RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	1,721,533	$0.00650	$11,190
Distribution			
Total Bills	1,161	$10.00	$11,610
First 200 KWH	229,648	$0.03058	$7,023
Next 600 KWH	633,749	$0.02540	$16,097
Excess KWH	858,137	$0.01770	$15,189
Subtotal	1,721,534		$49,919
Energy & Capacity			
First 200 KWH	229,648	$0.05728	$13,154
Next 400 KWH	437,638	$0.01517	$6,639
Next 600 KWH	504,228	$0.05034	$25,383
Excess KWH	550,019	$0.04618	$25,400
Subtotal	1,721,533		$70,576
Competitive Transition Charge			
First 200 KWH	229,648	$0.00237	$544
Next 400 KWH	437,638	$0.00213	$932
Next 600 KWH	504,228	$0.00210	$1,059
Excess KWH	550,019	$0.00194	$1,067
Subtotal	1,721,533		$3,602
Intangible Transition Charge			
First 200 KWH	229,648	$0.01101	$2,528
Next 400 KWH	437,638	$0.01044	$4,569
Next 600 KWH	504,228	$0.00976	$4,921
Excess KWH	550,019	$0.00901	$4,956
Subtotal	1,721,533		$16,974
Total Rate Revenue			$152,261

PPL Electric Utilities Corporation
Rate Schedule RTS (R)
Residential Service - Thermal Storage
Calculation of Effect of Proposed Rate vs. Current Tariff
Based on bill frequency distribution for 12 months ended December 2006

PRESENT RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	360,438,186	$0.00650	$2,342,848
Subtotal			$2,342,848
Distribution			
Total Bills	166,177	$16.45	$2,733,612
First 2 on-peak KW	326,061	$0.00	$0
Excess on-peak KW	866,581	$1.442	$1,249,610
Subtotal			$3,983,222
Energy & Capacity			
First 2 on-peak KW	326,061	$0.00	$0
Excess on-peak KW	866,581	$5.32	$4,610,211
All KWH	360,438,186	$0.03149	$11,350,198
Subtotal			$15,960,409
Competitive Transition Charge			
All KWH	360,438,186	$0.00032	$115,340
Intangible Transition Charge			
All KWH	360,438,186	$0.00810	$2,919,549
Total Rate Revenue			$25,321,368

PROPOSED RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	360,438,186	$0.00650	$2,342,848
Subtotal			$2,342,848
Distribution			
Total Bills	166,177	$17.65	$2,933,024
First 200 KWH	33,116,933	$0.0055	$182,143
Next 600 KWH	95,871,093	$0.0055	$527,291
Excess KWH	231,450,159	$0.0055	$1,272,976
Subtotal	360,438,185		$4,915,434
Energy & Capacity			
First 2 on-peak KW	326,061	$0.00	$0
Excess on-peak KW	866,581	$5.32	$4,610,211
All KWH	360,438,186	$0.03149	$11,350,198
Subtotal			$15,960,409
Competitive Transition Charge			
All KWH	360,438,186	$0.00032	$115,340
Intangible Transition Charge			
All KWH	360,438,186	$0.00810	$2,919,549
Total Rate Revenue			$26,253,580

Summary of Total Revenues

Total from bill distributions Proposed Rates	$26,253,580
Total from bill distributions Present Rates	$25,321,368
Rate Change Amount	$932,212
Percent	3.68%
2006 Rate revenue under Present Rates	$24,967,633
Rate Change Percent	3.68%
Amount	$918,809
2006 Projected Revenue under Proposed Rates	$25,886,442
2007 Rate revenue under Present Rates	$27,114,235
Rate Change Percent	3.68%
Amount	$997,804
2007 Projected Revenue under Proposed Rates	$28,112,039

PPL Electric Utilities Corporation
Rate Schedule RTD (R)
Residential Service - Time-of-Day
Calculation of Effect of Proposed Rate vs. Current Tariff
Based on bill frequency distribution for 12 months ended December 2006

PRESENT RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	4,728,544	$0.00650	$30,736
Distribution			
Total Bills	3,161	$15.89	$50,228
On-peak KWH	1,037,771	$0.04043	$41,957
Off-peak KWH	3,690,773	$0.01215	$44,843
Subtotal			$137,028
Energy & Capacity			
On-peak KWH	1,037,771	$0.09965	$103,414
Off-peak KWH	3,690,773	$0.02958	$109,173
Subtotal	4,728,544		$212,587
Competitive Transition Charge			
On-peak KWH	1,037,771	$0.00256	$2,657
Off-peak KWH	3,690,773	$0.00088	$3,248
Subtotal	4,728,544		$5,905
Intangible Transition Charge			
On-peak KWH	1,037,771	$0.02623	$27,221
Off-peak KWH	3,690,773	$0.00849	$31,335
Subtotal	4,728,544		$58,556
Total Rate Revenue			$444,812

PROPOSED RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	4,728,544	$0.00650	$30,736
Distribution			
Total Bills	3,161	$11.51	$36,383
First 200 KWH	625,788	$0.03465	$21,684
Next 600 KWH	2,415,971	$0.02878	$69,532
Excess KWH	1,686,784	$0.02005	$33,820
			$161,419
Energy & Capacity			
On-peak KWH	1,037,771	$0.09965	$103,414
Off-peak KWH	3,690,773	$0.02958	$109,173
Subtotal	4,728,544		$212,587
Competitive Transition Charge			
On-peak KWH	1,037,771	$0.00256	$2,657
Off-peak KWH	3,690,773	$0.00088	$3,248
Subtotal	4,728,544		$5,905
Intangible Transition Charge			
On-peak KWH	1,037,771	$0.02623	$27,221
Off-peak KWH	3,690,773	$0.00849	$31,335
Subtotal	4,728,544		$58,556
Total Rate Revenue			$469,203

Summary of Total Revenues	
Total from bill distributions Proposed Rates	$469,203
Total from bill distributions Present Rates	$444,812
Rate Change Amount	$24,391
Percent	5.48%
2006 Rate revenue under Present Rates	$439,905
Rate Change Percent	5.48%
Amount	$24,107
2006 Projected Revenue under Proposed Rates	$464,012
2007 Rate revenue under Present Rates	$468,704
Rate Change Percent	5.48%
Amount	$25,685
2007 Projected Revenue under Proposed Rates	$494,389

PPL Electric Utilities Corporation
Rate Schedule GS-1
Small General Service at Secondary Voltage
Calculation of Effect of Proposed Rate vs. Current Tariff
Based on bill frequency distribution for 12 months ended December 2006

PRESENT RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	1,901,806,480	$0.00600	$11,410,839
Subtotal			$11,410,839
Distribution			
Total Bills	1,718,122	$11.03	$18,950,886
First 5 KW	8,590,613	$0.00	$0
Excess KW	5,465,035	$2.27	$12,405,629
First 150 Hours	1,314,609,455	$0.02371	$31,169,390
Excess KWH	587,197,025	$0.01638	$9,618,287
Subtotal	1,901,806,480		$72,144,192
Energy and Capacity			
First 150 Hours	1,314,609,455	$0.06862	$90,208,501
Excess KWH	587,197,025	$0.04996	$29,336,363
Subtotal	1,901,806,480		$119,544,864
Competitive Transition Charge			
First 150 Hours	1,314,609,455	$0.00407	$5,350,460
Excess KWH	587,197,025	$0.00305	$1,790,951
Subtotal	1,901,806,480		$7,141,411
Intangible Transition Charge			
First 150 Hours	1,314,609,455	$0.01351	$17,760,374
Excess KWH	587,197,025	$0.01013	$5,948,306
Subtotal	1,901,806,480		$23,708,680
T. O. D. Metering	9,996	$14.45	$144,442
GIV			$2,331,427
GIC			$109,367
Total Rate Revenue			$236,535,222

PROPOSED RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	1,901,806,480	$0.00600	$11,410,839
Subtotal			$11,410,839
Distribution			
Total Bills	1,718,122	$11.50	$19,758,403
First 5 KW	8,590,613	$0.00	$0
Excess KW	5,465,035	$2.30	$12,569,581
First 150 Hours	1,314,609,455	$0.02442	$32,102,763
Excess KWH	587,197,025	$0.01360	$7,985,880
Subtotal	1,901,806,480		$72,416,627
Energy and Capacity			
First 150 Hours	1,314,609,455	$0.06862	$90,208,501
Excess KWH	587,197,025	$0.04996	$29,336,363
Subtotal	1,901,806,480		$119,544,864
Competitive Transition Charge			
First 150 Hours	1,314,609,455	$0.00407	$5,350,460
Excess KWH	587,197,025	$0.00305	$1,790,951
Subtotal	1,901,806,480		$7,141,411
Intangible Transition Charge			
First 150 Hours	1,314,609,455	$0.01351	$17,760,374
Excess KWH	587,197,025	$0.01013	$5,948,306
Subtotal	1,901,806,480		$23,708,680
T. O. D. Metering	9,996	$0.00	$0
GIV			$2,356,299
GIC			$113,910
Total Rate Revenue			$236,692,630

Summary of Total Revenues	
Total from bill distributions Proposed Rates	$236,692,630
Total from bill distributions Present Rates	$236,535,222
Rate Change Amount	$157,408
Percent	0.07%
2006 Rate revenue under Present Rates	$235,720,730
Rate Change Percent	0.07%
Amount	$165,005
2006 Projected Revenue under Proposed Rates	$235,885,735
2007 Rate revenue under Present Rates	$235,282,292
Rate Change Percent	0.07%
Amount	$164,698
2007 Projected Revenue under Proposed Rates	$235,446,990

PPL Electric Utilities Corporation
Rate Schedule GS-1
Volunteer Fire Co./Sr. Citizens Centers (G1V)
Calculation of Effect of Proposed Rate vs. Current Tariff
Based on bill frequency distribution for 12 months ended December 2006

PRESENT RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	26,526,284	$0.00650	$172,421
Distribution			
Total Bills	9,329	$7.96	$74,259
First 200 KWH	1,733,281	$0.02265	$39,259
Next 600 KWH	4,686,866	$0.02048	$95,987
Excess KWH	20,106,137	$0.01924	$386,842
Subtotal	26,526,284		$596,347
Energy & Capacity			
First 200 KWH	1,733,281	$0.05728	$99,282
Next 600 KWH	4,686,866	$0.05034	$235,937
Excess KWH	20,106,137	$0.04618	$928,501
Subtotal	26,526,284		$1,263,720
Competitive Transition Charge			
First 200 KWH	1,733,281	$0.00237	$4,108
Next 600 KWH	4,686,866	$0.00210	$9,842
Excess KWH	20,106,137	$0.00194	$39,006
Subtotal	26,526,284		$52,956
Intangible Transition Charge			
First 200 KWH	1,733,281	$0.01101	$19,083
Next 600 KWH	4,686,866	$0.00976	$45,744
Excess KWH	20,106,137	$0.00901	$181,156
Subtotal	26,526,284		$245,983
Total Rate Revenue			$2,331,427

PROPOSED RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	26,526,284	$0.00650	$172,421
Distribution			
Total Bills	9,329	$10.00	$93,290
First 200 KWH	1,733,281	$0.03058	$53,004
Next 600 KWH	4,686,866	$0.02540	$119,046
Excess KWH	20,106,137	$0.01770	$355,879
Subtotal	26,526,284		$621,219
Energy & Capacity			
First 200 KWH	1,733,281	$0.05728	$99,282
Next 600 KWH	4,686,866	$0.05034	$235,937
Excess KWH	20,106,137	$0.04618	$928,501
Subtotal	26,526,284		$1,263,720
Competitive Transition Charge			
First 200 KWH	1,733,281	$0.00237	$4,108
Next 600 KWH	4,686,866	$0.00210	$9,842
Excess KWH	20,106,137	$0.00194	$39,006
Subtotal	26,526,284		$52,956
Intangible Transition Charge			
First 200 KWH	1,733,281	$0.01101	$19,083
Next 600 KWH	4,686,866	$0.00976	$45,744
Excess KWH	20,106,137	$0.00901	$181,156
Subtotal	26,526,284		$245,983
Total Rate Revenue			$2,356,299

PPL Electric Utilities Corporation
Rate Schedule GS-1
Off-Peak Space Conditioning and Water Heating (G1C)
Calculation of Effect of Proposed Rate vs. Current Tariff
Based on bill frequency distribution for 12 months ended December 2006

PRESENT RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	3,071,599	$0.00600	$18,430
Subtotal			$18,430
Distribution			
All KW	2,300	$ 20.14	$46,322
All KWH	3,071,599	$0.01216	$37,351
Subtotal			$83,673
Energy & Capacity			
All KWH	3,071,599	$0.00000	$0
Competitive Transition Charge			
All KWH	3,071,599	$0.00000	$0
Intangible Transition Charge			
All KWH	3,071,599	$0.00236	$7,249
T. O. D. Metering	932	$14.95	$ 14.95
Total Rate Revenue			$109,367

PROPOSED RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	3,071,599	$0.00600	$18,430
Subtotal			$18,430
Distribution			
All KW	2,300	$21.00	$48,300
All KWH	3,071,599	$0.01300	$39,931
Subtotal			$88,231
Energy & Capacity			
All KWH	3,071,599	$0.00000	$0
Competitive Transition Charge			
All KWH	3,071,599	$0.00000	$0
Intangible Transition Charge			
All KWH	3,071,599	$0.00236	$7,249
T. O. D. Metering	932	$0.00	$0
Total Rate Revenue			$113,910

PPL Electric Utilities Corporation
Rate Schedule GS-3
Large General Service at Secondary Voltage
Calculation of Effect of Proposed Rate vs. Current Tariff
Based on bill frequency distribution for 12 months ended December 2006

PRESENT RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	8,529,776,577	$0.00600	$51,178,659
Subtotal			$51,178,659
Distribution			
All KW	24,062,868	$4.193	$100,895,606
First 200 Hours	4,649,162,261	$0.00086	$3,998,280
Next 200 Hours	3,040,976,039	$0.00068	$2,067,864
Excess KWH	839,638,277	$0.00057	$478,594
Subtotal	8,529,776,577		$107,440,344
Energy & Capacity			
All KW	24,062,868	$4.461	$107,344,454
First 200 Hours	4,649,162,261	$0.04844	$225,205,420
Next 200 Hours	3,040,976,039	$0.03684	$112,029,557
Excess KWH	839,638,277	$0.03519	$29,546,871
Subtotal	8,529,776,577		$474,126,302
Competitive Transition Charge			
First 200 Hours	4,649,162,261	$0.00209	$9,716,749
Next 200 Hours	3,040,976,039	$0.00165	$5,017,610
Excess KWH	839,638,277	$0.00160	$1,343,421
Subtotal	8,529,776,577		$16,077,780
Intangible Transition Charge			
First 200 Hours	4,649,162,261	$0.01183	$54,999,590
Next 200 Hours	3,040,976,039	$0.00925	$28,129,028
Excess KWH	839,638,277	$0.00888	$7,455,988
Subtotal	8,529,776,577		$90,584,606
T. O. D. Metering	30,343	$14.08	$427,229
G3V			$567,712
G3C			$1,156,908
Econ. Dev. Credits			($3,752,711)
Total Rate Revenue			$737,806,829

PROPOSED RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	8,529,776,577	$0.00600	$51,178,659
Subtotal			$51,178,659
Distribution			
All KW	24,062,868	$4.451	$107,103,825
First 200 Hours	4,649,162,261	$0.00000	$0
Next 200 Hours	3,040,976,039	$0.00000	$0
Excess KWH	839,638,277	$0.00000	$0
Subtotal	8,529,776,577		$107,103,825
Energy & Capacity			
All KW	24,062,868	$4.461	$107,344,454
First 200 Hours	4,649,162,261	$0.04844	$225,205,420
Next 200 Hours	3,040,976,039	$0.03684	$112,029,557
Excess KWH	839,638,277	$0.03519	$29,546,871
Subtotal	8,529,776,577		$474,126,302
Competitive Transition Charge			
First 200 Hours	4,649,162,261	$0.00209	$9,716,749
Next 200 Hours	3,040,976,039	$0.00165	$5,017,610
Excess KWH	839,638,277	$0.00160	$1,343,421
Subtotal	8,529,776,577		$16,077,780
Intangible Transition Charge			
First 200 Hours	4,649,162,261	$0.01183	$54,999,590
Next 200 Hours	3,040,976,039	$0.00925	$28,129,028
Excess KWH	839,638,277	$0.00888	$7,455,988
Subtotal	8,529,776,577		$90,584,606
T. O. D. Metering	30,343	$0.00	$0
G3V			$563,167
G3C			$962,522
Econ. Dev. Credits			($3,752,711)
Total Rate Revenue			$736,844,150

Summary of Total Revenues	
Total from bill distributions Proposed Rates	$736,844,150
Total from bill distributions Present Rates	$737,806,829
Rate Change Amount	-$962,679
Percent	-0.13%
2006 Rate revenue under Present Rates	$743,095,828
Rate Change Percent	-0.13%
Amount	-$966,025
2006 Projected Revenue under Proposed Rates	$742,129,803
2007 Rate revenue under Present Rates	$738,055,102
Rate Change Percent	-0.13%
Amount	-$959,472
2007 Projected Revenue under Proposed Rates	$737,095,630

PPL Electric Utilities Corporation
Rate Schedule GS-3
Volunteer Fire Co./Sr. Citizens Centers (G3V)
Calculation of Effect of Proposed Rate vs. Current Tariff
Based on bill frequency distribution for 12 months ended December 2006

PRESENT RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	6,714,553	$0.00650	$43,645
Distribution			
Total Bills	749	$7.96	$5,962
First 200 KWH	148,944	$0.02265	$3,374
Next 600 KWH	442,282	$0.02048	$9,058
Excess KWH	6,123,327	$0.01924	$117,813
Subtotal	6,714,553		$136,207
Energy & Capacity			
First 200 KWH	148,944	$0.05728	$8,532
Next 600 KWH	442,282	$0.05034	$22,264
Excess KWH	6,123,327	$0.04618	$282,775
Subtotal	6,714,553		$313,571
Competitive Transition Charge			
First 200 KWH	148,944	$0.00237	$353
Next 600 KWH	442,282	$0.00210	$929
Excess KWH	6,123,327	$0.00194	$11,879
Subtotal	6,714,553		$13,161
Intangible Transition Charge			
First 200 KWH	148,944	$0.01101	$1,640
Next 600 KWH	442,282	$0.00976	$4,317
Excess KWH	6,123,327	$0.00901	$55,171
Subtotal	6,714,553		$61,128
Total Rate Revenue			$567,712

PROPOSED RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	6,714,553	$0.00650	$43,645
Distribution			
Total Bills	749	$10.00	$7,490
First 200 KWH	148,944	$0.03058	$4,555
Next 600 KWH	442,282	$0.02540	$11,234
Excess KWH	6,123,327	$0.01770	$108,383
Subtotal	6,714,553		$131,662
Energy & Capacity			
First 200 KWH	148,944	$0.05728	$8,532
Next 600 KWH	442,282	$0.05034	$22,264
Excess KWH	6,123,327	$0.04618	$282,775
Subtotal	6,714,553		$313,571
Competitive Transition Charge			
First 200 KWH	148,944	$0.00237	$353
Next 600 KWH	442,282	$0.00210	$929
Excess KWH	6,123,327	$0.00194	$11,879
Subtotal	6,714,553		$13,161
Intangible Transition Charge			
First 200 KWH	148,944	$0.01101	$1,640
Next 600 KWH	442,282	$0.00976	$4,317
Excess KWH	6,123,327	$0.00901	$55,171
Subtotal	6,714,553		$61,128
Total Rate Revenue			$563,167

PPL Electric Utilities Corporation
Rate Schedule GS-3
Off-Peak Space Conditioning and Water Heating (G3C)
Calculation of Effect of Proposed Rate vs. Current Tariff
Based on bill frequency distribution for 12 months ended December 2006

PRESENT RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	16,524,550	$0.00600	$99,147
Subtotal			$99,147
Distribution			
All KW	18,081	$20.01	$361,801
All KWH	16,524,550	$0.01209	$199,782
Subtotal			$561,583
Energy & Capacity			
All KWH	16,524,550	$0.01738	$287,197
Competitive Transition Charge			
All KWH	16,524,550	$0.00199	$32,884
Intangible Transition Charge			
All KWH	16,524,550	$0.00977	$161,445
T. O. D. Metering	986	$14.86	$14,652
Total Rate Revenue			$1,156,908

PROPOSED RATE	Units	Rate	Rate Revenue
Transmission			
All KWH	16,524,550	$0.00600	$99,147
Subtotal			$99,147
Distribution			
All KW	18,081	$21.00	$379,701
All KWH	16,524,550	$0.00013	$2,148
Subtotal			$381,849
Energy & Capacity			
All KWH	16,524,550	$0.01738	$287,197
Competitive Transition Charge			
All KWH	16,524,550	$0.00199	$32,884
Intangible Transition Charge			
All KWH	16,524,550	$0.00977	$161,445
T. O. D. Metering	986	$0.00	$0
Total Rate Revenue			$962,522