PPL ELECTRIC UTILITIES CORPORATION

Direct Testimony
Statements 1-7

8/9/04

Docket No. R-00049255

PPL Electric Utilities Corporation
Docket No. R-00049255
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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

PPL Electric Utilities Corporation

Statement No. 1

Direct Testimony of John F. Sipics

Q. Please state your full name and business address.

A. John F. Sipics, Two North Ninth Street, Allentown, Pennsylvania 18101.

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

A. I am the President of PPL Electric Utilities Corporation ("PPL Electric" or the "Company").

Q. What is your educational background?

A. I graduated from Lehigh University in 1970, with a Bachelor of Science Degree in electrical engineering. I received a Master of Science Degree in electrical engineering from Lehigh University in 1977. From 1976 through 1981, I was adjunct lecturer in the Electrical Engineering Department at Lehigh University. I am a registered professional engineer in the Commonwealth of Pennsylvania.

Q. How long have you been employed by PPL Electric and in what capacities?

A. I was initially employed by PPL Electric as an Engineer in the System Planning Department in 1970. I progressed to Project Engineer before transferring to the System Operating Department in 1974. After a promotion to Operations Coordinator in 1976, I returned to System Planning as a Senior Project Engineer and served in various sections of System Planning until my appointment as Manager-Resource Planning in May 1989. In September 1993, I was promoted to the position of Manager-System Operation. In

November 1994, I was promoted to General Manager-Power Systems Support. In 1997, when Pennsylvania became one of the first states to open its electricity market to competition, as vice-president of PPL's retail energy supply group, I organized PPL's entry into the competitive retail electricity supply business. In October 1998, I was named Vice President of Delivery Services and Economic Development (later renamed Regulatory Support) in the Company's electricity delivery business. In March 1999, I also was appointed President of PPL's natural gas delivery business. In October 2001, I became Vice President-Asset Management for PPL Electric. In October 2003, I was named President of PPL Electric and Chief Executive Officer of PPL Gas Utilities.

Q. Mr. Sipics, briefly describe the subject matter of your testimony in this proceeding.

A. I will discuss three principal topics. First, I will explain PPL Electric's current financial condition and how it has deteriorated since the Company's last base rate increase in 1995. Second, I will describe PPL Electric's successful management initiatives to control costs while maintaining high quality and reliable service. Third, I will provide my perspective on this case and how important it is to the future success of electric utility industry restructuring in Pennsylvania.

Q. Are you sponsoring any exhibits in PPL Electric's filing?

A. I am sponsoring the Statement of Reasons which is included as Section A of Exhibit Future 1.

Q. Please describe PPL Electric's current financial condition.

A. In calendar year 2003, PPL Electric earned approximately $40 million, which equates to a return on equity of less than 2%. Return on equity is expected to decline to about 1% in 2004. To put these returns in perspective, the Commission's order in the Company's 1995 base rate case allowed an opportunity return on equity of 11.5%.

Q. Why has PPL Electric's financial condition deteriorated to this extent?

A. This inadequate earnings performance results from the combined impact of two factors: (1) the caps on PPL Electric's retail rates, and (2) increases in the costs of providing regulated distribution service. PPL Electric agrees that rate caps were an integral part of the electric restructuring process in Pennsylvania. And, in its 1998 restructuring settlement, the Company agreed to cap the sum of its transmission and distribution rates at 1997 levels through the end of 2004. In PPL Electric's case, its 1997 rates were set by the Commission's final order in the Company's 1995 base rate case. Because the 1995 rate increase was, in large measure, offset by decreases in energy costs experienced prior to that case, the Company's 1995 rates were essentially equal to rates established in 1986. As a practical matter, the Company's retail rates have remained essentially unchanged since 1986, a period of rate stability extending almost 20 years.

Q. What has happened to the costs of doing business over that time period?

A. Although PPL Electric's rates have remained stable since 1986, its costs of doing business have continued to grow. Each of us has seen significant cost increases in our daily lives. If there had not been any price increases in other goods and services since 1986, a loaf of bread would cost only 56¢; a Hershey bar would cost 40¢; and you could mail a letter for 22¢. Looking specifically at the electric utility business, since 1986, the cost to buy a pole has increased 85%; the price of a line truck has increased 50%; and the Company's health care costs for employees have increased by 150%. The result of these significant cost increases in a rate cap environment has been the decline in PPL Electric's earnings to a return on equity of less than 2%, as I mentioned earlier.

Q. What has been PPL Electric's response to this situation?

A. First and foremost, we have not wavered in our commitment to maintaining high quality and reliable service to our customers. We are not willing to reduce costs if that reduction would, in any way, jeopardize our operations. To ensure continuation of our high quality and reliable service, we have invested over $800 million in capital improvements since 1999. These capital improvements include system expansions, facility upgrades, facility replacements and new technologies. We also have maintained the same number of front-line forces performing lineman and electrical work as we had in 1990. And we are hiring and training additional employees in these front-line field positions, with 35 lineman helpers and 28 electrician helpers currently in training. None of these increased costs currently are reflected in the Company's retail rates.

Q. Do you believe that PPL Electric has been successful in its commitment to maintain high quality and reliable service?

A. Yes. The Commission and the electric utility industry in general use three indices to assess the reliability of an electric utility's service. These indices are CAIDI (Customer Average Interruption Duration Index), SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index). As measured by those reliability indices, PPL Electric has maintained high quality and reliable service throughout the transmission and distribution rate cap period and, except for one year, has met all PUC reliability standards. In the few instances when one of the indices declined, the Company focused on that aspect of its performance, determined the cause for the decline, and implemented appropriate initiatives to improve. PPL Electric continually monitors its overall performance and recently created a team to assess the integrity of its system during storms. The Company has met, and will continue to meet, its ongoing commitment to provide continuous, reliable, safe and dependable electric service to its customers.

Q. Are there other indications that PPL Electric's commitment to high quality and reliable service has been successful?

A. Yes. As discussed in the Statement of Reasons, PPL Electric has received numerous awards from J. D. Power and Associates for customer satisfaction in both the midsize business customer sector and the residential customer sector. And, in 2001, 2002 and 2003, PPL Electric ranked highest among combined gas-electric utilities nationwide in the American Customer Satisfaction Index. Customer opinion research shows that 88% of our customers rank PPL Electric above average as an electric service provider. On a scale of 1 to 10 with "10" defined as "outstanding," PPL Electric received an overall satisfaction score of 8.3. In response to the question, "How does the term 'reliable electric service' describe PPL Electric," customers scored PPL Electric at 8.7 on a scale of 1 to 10 with "10" defined as "perfectly."

Q. In addition to maintaining its commitment to high quality and reliable service, how did management respond to these cost increases in a rate cap environment?

A. We managed our costs in a very focused and disciplined way. Specifically, we pursued an aggressive program of cost effective operations in three areas. First, we made targeted reductions in our staffing levels. When the electric utility industry was restructured in 1999, the Company had approximately 3,800 employees; it now has approximately 3,000. In June 2002, PPL Electric eliminated 243 positions, but none of these positions were in field operations.

In fact, as I mentioned earlier, the Company has the same number of front line forces performing lineman and electrical work as it had in 1990. Second, we utilized new technology to manage costs. One example discussed in the Statement of Reasons is the Work Management System which manages workflow more effectively. Another example is the Automated Meter Reading ("AMR") system. The AMR project required the Company to replace current meters with sophisticated AMR meters for all 1.3 million of its customers. These AMR meters will reduce our costs and will provide an excellent platform for future initiatives in the competitive electric supply market. Third, we reviewed, and where appropriate modified, our business processes. Examples set forth in the Statement of Reasons include implementation of a maintenance priority system, increased utilization of existing infrastructure and installation of a new customer information system.

Q. In your opinion, has PPL Electric been effective in managing its business over the past 20 years?

A. Yes. The results speak for themselves. PPL Electric's rates have remained essentially unchanged since 1986. During that nearly 20-year period of rate stability, we were able to maintain high quality and reliable service as evidenced by reliability indices and industry awards. Moreover, PPL Electric's rates compare favorably with other electric utilities. A PPL Electric residential customer using 900 KWH of electricity per month pays 11.6% less than the Pennsylvania average; 24% less than Mid-Atlantic average; and 6.3% less than the national average for electric service. More fundamentally, we have not lost sight of our obligation to be a good corporate citizen and a vital part of the communities we serve. As detailed in the Statement of Reasons, the Company has played a vital role in bringing a significant number of jobs to its service area. PPL Electric has offered innovative and effective programs to assist its customers who experience problems with their ability to pay their electric bill.

Q. How should the Commission reflect this management effectiveness in consideration of the Company's request for a distribution rate increase?

A. The Company's rate of return expert, Paul R. Moul, recommends, in Statement No. 9, that the Company be allowed an opportunity to earn a rate of return on common equity of 11.50%. This recommendation is at the upper end of the range of equity returns developed in his study. In my opinion, PPL Electric's management effectiveness over nearly a 20-year period is one of several considerations that support a return on equity finding at the high end of Mr. Moul's range, that is, an 11.50% return on equity.

Q. Mr. Sipics, what is your overall perspective on this rate increase request?

A. This is a unique and important proceeding because it is the first distribution-only rate case filed by a major Pennsylvania electric distribution company since restructuring of the electric utility industry in the Commonwealth.

Q. Has the unique nature of this case been reflected in PPL Electric's filing?

A. Yes. Recognizing the results of restructuring the electric utility industry, this filing has been prepared on the basis of a distribution-only business, as described in more detail in Statement No. 5, the direct testimony of Joseph M. Kleha. Excluded from the filing are financial data related to operations subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"); operations related to generation; operations related to Provider of Last Resort ("POLR") service; and the recovery of stranded costs. In addition, the filing includes several pricing proposals that move the Company's rate design from rates set on a usage basis toward rates set on a demand or customer basis. As explained by Douglas A. Krall, in Statement No. 4, this proposed approach to designing rates more accurately reflects the fact that costs incurred by a distribution-only company tend not to vary with customer usage.

Q. Are there other elements of this filing that reflect the changed nature of the electric utility industry?

A. Yes. The Company is proposing a Distribution System Improvement Charge ("DSIC") to provide for recovery of the fixed costs of new distribution facilities that go into service between base rate proceedings. PPL Electric also is proposing a Transmission Service Charge ("TSC") to provide for recovery of transmission service charges that PPL Electric must pay to the PJM Interconnection, LLC ("PJM"). And, we have not forgotten the basics. As discussed in more detail in Statement No. 7, the direct testimony of Timothy R.

Dahl, PPL Electric is proposing a 23% increase in funding for two programs created to assist low-income customers. The Company also is proposing a Community Betterment Initiative with initial funding from ratepayers and shareowners of $2 million annually. And, it is proposing to *extend* customer funding for the Sustainable Energy Fund at 0.01¢/KWH, or approximately $3.4 million per year.

Q. In your opinion, how does this filing relate to the restructuring of the electric utility industry in Pennsylvania?

A. This distribution rate increase request is the next logical step in that process. In the settlement of our restructuring case, we agreed to caps on both delivery rates and generation rates. The transmission and distribution rate cap temporarily suspended the filing of rate increase requests with the Commission. However, that rate cap has an explicit termination date. In PPL Electric's case, the transmission and distribution rate cap ends December 31, 2004. All parties clearly understood that rate increase requests are a normal part of a regulated utility's business. We are now at the point in the process when those requests can be filed. And, as I discussed earlier, PPL Electric's financial condition requires that it seek a distribution rate increase to be effective at the end of the transmission and distribution rate cap period.

Q. Can the Commission reaffirm its strong support of industry restructuring in its decision in this case?

A. Yes. This case will give the Commission an opportunity to demonstrate its support for viable and financially healthy distribution companies as an important element in the restructured electric utility industry. Although the restructuring effort focused primarily on the deregulation of generation, the success of a competitive supply market requires, among other things, reliable delivery services by regulated distribution companies. The Commission's actions in this case will be closely followed by all stakeholders in Pennsylvania. Moreover, because Pennsylvania is a leader in the restructuring of the electric utility industry, its actions in this case also will be followed throughout the country.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

PPL Electric Utilities Corporation

Statement No. 2

Direct Testimony of Joseph R. Schadt

Direct Testimony of Joseph R. Schadt

Q. Please state your name and business address.

A. Joseph R. Schadt, Two North Ninth Street, Allentown, Pennsylvania 18101.

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

A. I am employed by the PPL Services Corporation as Director – Financial Support Services.

Q. What are your responsibilities as Director – Financial Support Services?

A. I am responsible for compiling the corporate operating budget, administering our functional group (responsibility center) budget control system, and preparing financial forecasts and various special studies which require projections of corporate financial performance.

Q. What is your educational background?

A. I received a Bachelor's Degree in Accounting from Wake Forest University in May 1979. Upon graduation, I worked for Duke Power Company for two years in the Accounting Systems and Forecasting departments. In July 1981, I began working for Pennsylvania Power & Light Company.

Q. How long have you been employed by PPL or a subsidiary of PPL Corporation, and in what capacities?

A. I began my employment with Pennsylvania Power & Light Company as an Accountant in the General Accounting Department and remained there for four years, progressing to the position of Senior Accountant. In General Accounting, I participated in the maintenance and closing of Pennsylvania Power & Light's books and records and had primary responsibility for the calculation of the actual cost components of the Energy Cost Rate, unbilled revenues and the miscellaneous billing function. Subsequently, I transferred to the Financial Reporting Department where I remained for nine years. I was promoted to Accounting Analyst in Financial Reporting and my responsibilities included the completion and filing of the Annual Report to Shareowners, Forms 10-Q and 10-K for the Securities and Exchange Commission and the FERC Form 1. Through my experience in General Accounting and Financial Reporting, I was able to develop a thorough knowledge of accounting and reporting concepts applicable to the electric utility industry in general and PPL Electric in particular. In November 1994, I was promoted to the position of Supervisor-- Accounting Research. In this position, I had responsibility for developing the Company's policies regarding open accounting issues applicable to the industry. In addition, I was significantly involved in special projects, such as transmission access, stranded costs, and other deregulation issues. In February 1996, I was promoted to Manager—Financial Support Services and in January 2000 I was promoted to Director—Financial Support Services, my current position. In this position, I have primary responsibility for PPL Corporation and its subsidiaries' (including PPL Electric) financial forecasting, budgeting and business planning functions.

Q. Are you active in any professional organizations?

A. I am a past chairman and a current member of the Accounting Standards Committee of the Edison Electric Institute.

Q. What is the purpose of your testimony?

A. My testimony will describe the derivation of data used to calculate financial results for the Historic Test Year ending December 31, 2003 and to project the financial results for the Future Test Year ending December 31, 2004.

Q. Mr. Schadt, are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring portions of the following: Exhibit Regs. Part I, a multi-page document entitled "General Information"; Exhibit Regs. Part II, a multi-page document entitled "Primary Statements of Rate Base and Operating Income"; Exhibit Regs. Part III, a multi-page document entitled "Rate of Return"; Exhibit Regs. Part V, a multi-page document entitled "Plant and Depreciation Supporting Data, Including Related Depreciation Study Report"; Exhibit Regs. Part VI, a multi-page document entitled "Unadjusted Comparative Balance Sheets and Operating Income Statements"; Exhibit Regs. Section 53.52, a multi-page document entitled "Information in Response to Section 53.52 of the Commission Regulations"; Exhibit Historic 1, a multi-page document entitled "Summary of Measures of Value & Rate of Return for the Year Ended December 31, 2003"; and Exhibit Future 1, a multi-page document entitled "Summary of Measures of Value & Rate of Return for the Year Ending December 31, 2004."

Q. Please explain how and why the foregoing exhibits were prepared.

A. With regard to Exhibit Regs. I, II, III, V and VI, Section 53.53 of the Commission's regulations requires that all electric utilities seeking a general rate increase in revenues exceeding $1,000,000 must provide specific responses to about 100 questions. The regulation categorizes these questions into six parts as follows:

I. General Information--Electric Utilities

II. Primary Statements of Rate Base and Operating Income

III. Rate of Return

IV. Rate Structure and Cost Allocation

V. Plant and Depreciation Supporting Data, including Related Depreciation Study Report

VI. Unadjusted Comparative Balance Sheets and Operating Income Statements

PPL Electric's responses to the questions follow the same pattern. Thus, responses to pertinent questions regarding general information are found in Exhibit Regs. I, "General Information." Responses to questions regarding primary statements of rate base and operating income are found in Exhibit Regs. II, "Primary Statements of Rate Base and Operating Income," and so forth.

Generally, PPL Electric's responses to the questions reflect unadjusted book data for the historic year and unadjusted projected data for the future test year. The various ratemaking adjustments are reflected in Exhibit Historic 1 and Exhibit Future 1, respectively.

Individuals responsible for the response to a particular question are noted in the upper right-hand corner of the page on which the question is stated. If more than two individuals were involved in the preparation of a response, the notation is "Various."

With regard to Exhibit Regs. Section 53.52, the Commission's regulations also provide that in addition to the questions set forth in Section 53.53, utilities seeking a rate increase must also provide responses to the questions set forth in Section 53.52. PPL Electric's responses to the questions set forth in Section 53.52 are found in this separate exhibit.

Exhibits Historic 1 and Future 1 provide book and projected data as well as various ratemaking adjustments, for the years ended December 31, 2003 and December 31, 2004, respectively. As with Exhibit Regs. I to VI, individuals responsible for the preparation of a particular schedule in Exhibit Historic 1 or Future 1 are noted in the upper right-hand corner.

Q. PPL Electric is requesting an increase in electric distribution rates of approximately $164.4 million annually. Is this requested increase supported by data for a future or experienced test year?

A. PPL Electric will rely primarily on data for a future test year ending December 31, 2004. These data are included in Exhibit Future 1. The Commission's regulations require that a public utility which uses a future test year also must submit data for a historic year, consisting of the twelve months preceding the future test year. As a result, PPL Electric also has submitted data for the 12 months ended December 31, 2003. These data are set forth in Exhibit Historic 1.

Q. Mr. Schadt, will you now briefly explain how the schedules included in Exhibits Historic 1 and Future 1 are organized?

A. Yes. These exhibits contain information required by the Commission's regulations and each contains a series of schedules. The schedules are grouped into four major categories: Schedule A-1 is a Statement of Reasons for the proposed increase. Those schedules prefixed with the letter "B" are financial statements and data regarding PPL Electric's securities and capital structure as of December 31, 2003 and December 31, 2004. Those schedules prefixed with the letter "C" relate to measures of value as of December 31, 2003 and December 31, 2004. Those schedules prefixed with the letter "D" pertain to operating revenues, expenses and income for the years ended December 31, 2003 and December 31, 2004, and adjustments thereto.

It should be noted that for both Exhibit Historic 1 and Exhibit Future 1 rounding to the nearest thousands of dollars generally was employed.

The various schedules in Exhibits Historic 1 and Future 1 are consistently numbered. For example, the claim for Plant Materials and Operating Supplies is Schedule C-5 in both exhibits. This should facilitate working with both documents simultaneously.

Q. You have stated that the data in Exhibit Future 1 are for the 12 months ending December 31, 2004. This is obviously a projection of future data. Will you please explain the source of this future data?

A. The basic data in Exhibit Future 1 was derived from PPL Electric's budget and forecast figures for the 12 months ending December 31, 2004. I will explain the procedures followed in preparing the Operating Budget later in my testimony. D. A. Krall, PPL Electric's Manager-Regulatory Strategy, explains the procedures followed in preparing the Capital Budget. In effect, the budget figures take the place of PPL Electric's actual book figures which serve as the basis for the December 31, 2003 data in Exhibit Historic 1.

Q. Mr. Schadt, would you describe the material presented on Schedules B-1 through B-9 of Exhibits Historic 1 and Future 1?

A. Schedules B-1 show the balance sheets of PPL Electric at December 31, 2003 and December 31, 2004, which include the assets and liabilities related to the electric utility operations, and investments in non-utility property and associated companies.

These balance sheets exclude the assets and liabilities of PPL Transition Bond Company, LLC, a wholly owned subsidiary formed to issue transition bonds under the Customer Choice Act. Schedules B-2 are statements of electric utility operations showing the operating revenues and expenses and income for the year ended December 31, 2003 and year ending December 31, 2004. Electric operating revenues shown on these schedules are set forth by source in Schedules B-3.

Schedules B-4 provide the operation and maintenance expenses of the electric utility operations by detailed accounts, including the major categories of expense: power production, transmission, distribution, customer accounts, customer service and informational, sales, and administrative and general. The expenses in the power production category represent the cost of purchased power and include, among other items, purchases to meet Provider of Last Resort ("POLR") requirements, nuclear decommissioning costs and purchases from non-utility generation companies. Power production costs are not germane to the determination of distribution revenue requirements in this filing. Later in my testimony I will explain certain allocations that were used to arrive at projections of operation and maintenance expenses in the categories shown on both Schedules B-2 and B-4 of Exhibit Future 1.

Schedules B-5 present the details of taxes applicable to the electric utility operations. The embedded cost of debt and preferred capital at December 31, 2003 and December 31, 2004 are shown on Schedules B-6 and B-7. PPL Electric's capital structure from 1999 through December 31, 2004 is shown on Schedules B-8.

All the data shown in Schedules B-1 through B-8 were taken either from the books and records of PPL Electric for the 12 months ended December 31, 2003 and prior, or were derived from operating and construction budget data for the 12 months ending December 31, 2004.

Schedules B-9 set forth the claimed composite rate of return as of December 31, 2003 and December 31, 2004. In each instance, the capitalization ratios at the end of the respective year, as shown on Schedule B-

8, were used. The composite cost rate for long-term debt (Schedule B-6) and the composite cost rate for preferred (Schedule B-7) are reflected as embedded costs. As to common equity, the claimed rate of return on common equity is 11.5%. PPL Electric's rate of return expert, Paul R. Moul, is recommending, and his studies support, a fair rate of return on common equity at this level. The overall rate of return reflected on Schedule C-1 in Exhibit Future 1 will produce a return on common equity of 11.5%.

Q. Please describe the source and method used to establish the book cost of plant shown in the accounts of PPL Electric.

A. The accounts of PPL Electric are kept in accordance with the Uniform System of Accounts prescribed by the PUC and the Federal Energy Regulatory Commission ("FERC") for Electric Utilities and Licensees. By several orders at Docket No. E.O.C. 34, the last dated December 30, 1947, the PUC determined the original cost of PPL Electric's plant as of November 30, 1947. Since that time, PPL Electric has recorded its plant transactions in accordance with the Commission's required system of accounts. PPL Electric's books, therefore, reflect the original cost of its plant at December 31, 2003.

Q. Are these accounts audited?

A. They are audited annually by an independent certified public accounting firm. In addition, the FERC and PUC audit staffs conduct periodic audits.

Q. How do you determine that all property reflected in Account 101, Plant In Service, as shown on Page 1 of Schedules B-1, is actually in service?

A. The Asset Management and Benefit Accounting Section of PPL Services maintains Fixed Asset Records for PPL Electric which represent a Physical Inventory of all property in service. The dollar value total of the Continuing Property Records is the same as the balance shown in Account 101 at December 31, 2003.

The Uniform System of Accounts requires that utilities record all construction and retirements of electric plant by means of work orders or job orders. In addition, the work order system must show the nature of each addition to, or retirement from, electric plant, the total cost thereof, and the plant account or accounts affected.

PPL Electric has maintained such a work order system since the establishment of its Continuing Property Records system in 1937. Under this system, an authorized capital work order is used for all work performed.

When any unit of property is taken out of service permanently, PPL Electric personnel record the removal under a work order and transmit that information to the Asset Management and Benefit Accounting Section, where the necessary retirement accounting entry is made. Because many retirements can occur in connection with capital improvement projects, the retirement work is part of a construction authorization.

Costs of new construction are reported by work order number and Asset Management accumulates, by work order, all costs associated with a specific job. At the completion of the job, Asset Management receives reports from construction forces which show the date the project was placed in service and a complete inventory of property constructed. Based on this information and the costs accumulated under the work order, the property constructed is recorded in appropriate detail on PPL Electric's Continuing Property Records. With this system and its supporting detail, the costs comprising the total value of any item recorded as Plant In Service can be supported and verified through an audit by the various regulatory agencies which I previously identified.

Q. Mr. Schadt, would you explain Schedules C-5, "Plant Materials and Operating Supplies"?

A. Schedules C-5 reflect the amount required to be invested in the materials and supplies stored at service area storerooms to supply line crews. Pages 1-3 of Schedule C-5 in Exhibit Historic 1 shows the average dollars invested by PPL Electric in materials and operating supplies for the thirteen months ended December 31, 2003 plus the stores expense applicable to this inventory balance.

Monthly detail of materials and operating supplies on a projected basis for the 13 months ending December 31, 2004 are shown on pages 1-3 of Schedule C-5 in Exhibit Future 1.

Q. Mr. Schadt, can you provide any background on how the Future Test Year Financial Statements were prepared?

A. The Future Test Year financial statements and data have been based on information which the Company used to prepare its 2004 Operating and Capital

Budgets. Generally, this unadjusted projected data has been utilized in responding to the Commission's filing regulations. The various ratemaking adjustments are reflected on the D-Schedules of Exhibit Future 1.

Q. Please summarize the additional adjustments made on the D Schedules?

A. We prepared various other applicable rate case adjustments (see Future Test Year D Schedules for the other applicable pro-forma rate case adjustments). Three of the largest Schedule D adjustments were to: (1) Decrease transmission and distribution wages, taxes, and benefits by about $6.0 million for employee reductions primarily due to the Automated Meter Reading Project as noted on Future Test Year Schedules D-5 and D-9; (2) Increase distribution operating expenses by about $4.8 million for the increase in the cost of social programs as noted on Future Test Year Schedule D-8; and (3) Increase distribution operating expenses by about $3.0 million for the amortization of the Hurricane Isabel deferred costs as noted on Future Test Year Schedule D-10.

Q. Mr. Schadt, were you also responsible for the preparation of certain exhibits which accompany your direct testimony?

A. Yes. Exhibit JRS1 through Exhibit JRS4 were prepared under my supervision. I will be specifically referring to each of the exhibits in the balance of my testimony.

Q. Would you please explain how the operating budget process is carried out by PPL Electric?

A. Yes. *In explaining the budget process, I will be referring to certain exhibits (JRS1 to JRS4) which accompany my direct testimony. I was responsible for* preparing these exhibits. During the summer of each year, PPL Corporation's Business Planning Group begins preparing a detailed operating budget for the succeeding calendar year. Information used in compiling the operating budget generally can be categorized into three major groups: (1) that which is of a specialized nature (e.g., depreciation and amortization, financing, taxes) and is generally supplied by a PPL Services Corporation staff group having the expertise in forecasting this information; (2) that which comes directly from PPL Electric (e.g., employee levels and other operating costs such as materials, contract work, postage, rents); and (3) Service Group support costs, which are ultimately fully charged and/or allocated to PPL Corporation subsidiaries, including PPL Electric.

In developing specialized information provided by PPL Services Corporation staff groups, each of the staff groups develops its specific phase of the budget based on their specific experience and expertise. Specialized data from each PPL Services Corporation staff group is coordinated with other staff groups requiring this information to complete their phase of the budgeting process. For example, depreciation and interest expense information is needed for the tax budget to be completed.

PPL Electric's Business Services Group is responsible for coordinating detailed budget information supplied directly to it from departments and responsibility centers within PPL Electric. Budgeted sales and capital expenditure information are significant pieces of information that PPL Electric's departmental personnel supply to the Business Services Group. Additionally, each of PPL Electric's responsibility centers develops its own operation and maintenance budget and forwards it to the PPL Electric's Business Services Group, which then summarizes the budgets and presents them for review and approval by PPL Electric's executive management.

After executive management approves the budget, the data is released to my functional group, Financial Support Services, where the data is incorporated into the overall PPL Electric's operating budget.

In developing Service Group support costs for PPL Electric, each Service Group computes the level and expected cost of providing identifiable services (direct costs) to PPL Electric based on discussions of required services between the Support Group and PPL Electric personnel. The Service Groups submit these direct support costs to Financial Support Services. Additionally, the Service Groups identify and submit to Financial Support Services budgeted costs that are not directly identifiable and chargeable to a specific PPL Corporation affiliate but instead benefit various PPL Corporation affiliates (indirect costs). Financial Support Services has developed an allocation methodology, as recommended in the Commission's 2002 Focused Management and Operations Audit, to distribute these indirect support costs to PPL Electric and other PPL Corporation subsidiaries. After this process is completed, direct and indirect support costs are accumulated and incorporated into PPL Electric's Operating Budget.

After the final pieces of the budget are received from all three groups discussed above and approvals have been obtained, a tentative operating budget is prepared for PPL Electric. The tentative budget is reviewed with management with particular emphasis on key operational and financial indicators. After this review, the final budget is prepared and reviewed with the President and Board of Directors of PPL Electric. This budget is the key tool used by PPL Electric and senior management to establish an operating plan for the upcoming year and for measuring actual results against this plan.

Q. You stated that certain specialized data for the budget are provided by PPL Services Corporation staff groups. Could you tell us specifically what data are provided, and who provides this data?

A. Yes. Exhibit JRS1 lists the specific PPL Services Corporation staff groups responsible for providing specialized data and describes the data provided by those groups.

Q. You also stated that the remaining data for your operating budget comes from responsibility centers. What are responsibility centers, and how many responsibility centers does PPL Electric have?

A. The PPL Electric organization is broken down into six major departments. Each department is subdivided into functional groups referred to as responsibility centers. Each responsibility center has an assigned manager who is responsible for all costs incurred by that responsibility center. Each employee is assigned to a particular responsibility center. PPL Electric has 93 active responsibility centers. Exhibit JRS2 contains a list of the responsibility centers providing data for the 2004 Operating Budgets.

Q. What type of data do they provide?

A. PPL Electric provides a projection of their employee levels for the year that becomes the basis for projecting total wages. They also provide a budget of their other operating costs.

Q. Could you explain how the budget for wages is determined?

A. Yes. Early in the summer, Financial Support Services notifies the affiliates of the "Date of Estimate", which is the starting point date at which the system determines the number of employees, and their associated wages, in each responsibility center. Any changes from the Date of Estimate starting point, including new hires, decreases due to work force reductions or retirements and changes in salary levels, must be identified. Employee levels are reviewed and approved in conjunction with the overall budget review.

The budget system automatically calculates a budget for wages based on the starting level of employees and their actual earnings and the employee changes input. The system then applies assumed management and bargaining unit wage changes.

As departments budget for their employee levels, they generally allocate their available manpower by functional activity. As part of this process, they designate the applicable accounting to be charged— to capital or expense. Wages identified as expense ultimately appear on the Future Test Year Schedule B-2 income statement as an expense.

Q. You mentioned the budget for other operating costs. What costs fall into this category?

A. The Company's budgeting system requires budgeting by category of expenditure referred to as budget items. Exhibit JRS3 is a list of PPL Electric's various budget items.

Q. How are these budget items estimated?

A. Non-payroll requirements, such as rents, materials and contractors, are generally entered by budget item and functional activity, and in the month or months the expenses are anticipated. Budgets for payroll and non-payroll budget items are then approved electronically and then summarized by department for review by the department vice presidents and president.

Q. As part of the Future Test Year data in the present rate filing, budget expenditures have been provided by account. Do the departments also budget by account?

A. No. The budget is created by category of expenditure (budget items listed in Exhibit JRS3) and sometimes by functional activity. We believe it is more meaningful to budget and monitor expenditures by category of expense (e.g., payroll, employee expenses, material and supplies) rather than by FERC accounts. However, to satisfy the requirements for this rate filing, we have allocated expenditures into FERC accounts. This was accomplished by first allocating operating and maintenance costs budgeted by category of expenditures to FERC accounts where the budget classification was specifically identifiable to those accounts. For those budget classifications not identifiable to a specific FERC account, the total remaining budgeted expenditures were allocated to FERC accounts based on the same relationship to the total as the actual costs shown for the Historic Test Year operating and maintenance expenditures, which are reported by both budget classification and FERC account.

Q. How was the operating budget used in this rate filing?

A. The operating budget was used as the basis for forecasting PPL Electric's Operating Income for the test year ended December 31, 2004. Please refer to Attachment II-E-1. The forecasted data shown in Attachment II-E-1 was reformatted to correspond to FERC account classifications and is shown in Schedule B-2 of Exhibit Future 1 and throughout PPL's responses to the filing regulations.

Q. Are you aware of the requirement that a comparison of actual to budget data is to be supplied quarterly when a utility utilizes a Future Test Year?

A. Yes. In preparation for complying with this requirement, Exhibit JRS4 has been provided, showing a breakdown of revenues and expenses for electric operations for the Future Test Year into calendar quarters beginning in January of 2004 and ending December of 2004. The Company will provide quarterly comparisons of actual results to the budget as shown in Exhibit JRS4 as the actual data becomes available.

Q. Does this conclude your direct testimony?
A. Yes, it does.

PPL Electric Utilities Corporation

Exhibit JRS1

Docket No. R-00049255

PPL ELECTRIC UTILITIES CORPORATION
SPECIALIZED INFORMATION USED IN COMPILING THE OPERATING BUDGET

1. DEPRECIATION AND AMORTIZATION – Information is supplied by PPL Services *Corporation's Asset Management and Analysis Section of the Financial Department.*
2. FINANCING – Information is supplied by PPL Services Corporation's Finance and Treasury Section of the Financial Department.
3. TAXES – Information is supplied by PPL Services Corporation's Tax Section of the Financial Department.

PPL Electric Utilities Corporation

Exhibit JRS2

Docket No. R-00049255

PPL Electric Utilities
2004 Responsibility Centers

Business Line	Section	Responsibility Center	Description	Responsibility Center Head
PPL Electric Utilities:	President	21	PPL Electric Utilities	Sipics,John F
Automated Meter Reading:	AMR	709	AMR Project	Bujnowski,Bernard J
Asset Management:	Administration	900	Asset Management	Cole,David G
	Business Planning	808	Business Planning	Dreisbach,Anthony F
		807	Utility Business Services	Swankoski,Linda J
	Regulatory Strategy	924	Regulatory Strategy	Krall,Douglas A
	Asset Financial Evaluation	919	Asset Financial Evaluation	Cole,David G
		909	Load Analysis	Woodruff,David R
		925	Pricing & Contract Administration	Kasper,Oliver G
	Asset Operations Evaluation	601	Asset Operations Evaluation	Smith,Gregory J
		663	System Dev & Tech Support	Covaleski,Donald R
		870	Asset Maintenance & Reliabilty	Filipovits,R W
		878	System Maint Engrg-Trans & Sub	O'Neill,Michael J
	Interconnection Affairs	602	Interconnection Affairs	Laczo,Gabriel
Engineering & Design:	Administration	880	Engineering & Design	Schleicher,David E
	Asset Operations	603	Asset Operations Distribution	Rotz,Alan C
		661	T&D Operations	Grover,Robert D
	Design Engineering	883	Substation Design	Shoemaker,Martha D
		881	Transmission Design	Faisetty,John D
		665	Relay Test	Diehl,Gerald
	Standards	876	Substation Standards	Zemyan,Nicholas A
Resource Management:	Resource Management	526	Resource Management	Stathos,Thomas C
		530	Field Resource Management West	Daise,Thomas L
		540	Field Resource Management East	Swenson,Michael A
	Transportation Services	590	Transportation Services	Keller,Wesley C
		591	Transportation East Region	Shemanski,Stanley J
		595	Transportation West Region	Reisinger,Chas F
Technology:	CS Tech	702	Technical Support Services	Milot,John M
		713	Customer System Support	Johnson,Peter C
	Technology Applications	703	IT Planning & Business Support	Anoia,Crelia A
		704	IT Administration	Walton,David P
Customer Services:	Customer Services	705	Customer Services	Geneczko,Robert M
	Customer Contact Operations	707	Customer Contact Operations	Ling,David A
		708	On Track Arrearage	Ling,David A
	Regulatory Prog & Business Svcs	701	Regulatory Programs & Bus Services	Dahl,Timothy R
	Revenue Protection	736	Revenue Protection	Jones,Daniel A
	Community & Economic Development	911	Community & Economic Development	Bernhard,Donald M
		882	Real Estate Services	Farley,Robert J

PPL Electric Utilities
2004 Responsibility Centers

Business Line	Section	Responsibility Center	Description	Responsibility Center Head
Field Services:	**Field Services**	400	Vice President	Gombos,Robert S
	Field Services Administration	405	Field Services West	Lapos,Mark J
	Field Services Administration	440	Field Services East	Lapos,Mark J
	Metering Support	733	Metering Support	Santarelli,Paul D
	System Shops	872	Systems Shops	Santarelli,Paul D
	Utilities Business Consulting	670	Utilities Business Consulting	Kramer,Joann J
	Lancaster Region	410	Field Services Lancaster	Cook,Robert J
		411	Field Services Lancaster Design	Preziosi,Darryl P
		413	Field Services Lancaster T/D	Cook,Robert J
		414	Field Services Lancaster M/E	Cook,Robert J
		416	Field Services Lancaster East Design	Anspach,Robert J
		417	Field Services Lancaster East Metering	Melenchek,Lawrence S
		418	Field Services Lancaster East T/D	Cook,Robert J
		419	Field Services Lancaster East M/E	Cook,Robert J
	Susquehanna Region	420	Field Services Susquehanna	Gaida,Francis J
		421	Field Services Susquehanna Design	Koslap,Robert M
		422	Field Services Susquehanna Metering	Flory,Gene
		423	Field Services Susquehanna T/D	Gaida,Francis J
		424	Field Services Susquehanna M/E	Gaida,Francis J
		436	Field Services Sunbury Design	Weston,Robert E
		438	Field Services Sunbury T/D	Gaida,Francis J
		439	Field Services Sunbury M/E	Gaida,Francis J
	Harrisburg Region	430	Field Services West Shore	Howell,Timothy R
		426	Field Services Harrisburg Design	Seip,Sheldon S
		427	Field Services Harrisburg Metering	Lyall,Eugne
		428	Field Services Harrisburg T/D	Howell,Timothy R
		429	Field Services Harrisburg M/E	Howell,Timothy R
		431	Field Services West Shore Design	Przyuski,Walter
		433	Field Services West Shore T/D	Howell,Timothy R
		434	Field Services West Shore M/E	Howell,Timothy R
	Lehigh Region	445	Field Services Lehigh	Reed,Denis E
		446	Field Services Lehigh Design	Hartman,Kenneth N
		447	Field Services Lehigh Metering	Bicking,Donald
		448	Field Services Lehigh T/D	Reed,Denis E
		449	Field Services Lehigh M/E	Reed,Denis E
		461	Field Services Bethlehem/Buxmont Design	Leonard,Bruce E
		463	Field Services Bethlehem T/D	Reed,Denis E

Business Line	Section	Responsibility Center	Description	Responsibility Center Head
		464	Field Services Bethlehem M/E	Reed,Denis E
	Central Region	455	*Field Services Central*	Compierchio,Joseph M
		456	Field Services Central/WB Design	Lehman,Dennis R
		458	Field Services Central/WB T/D	Compierchio,Joseph M
		459	Field Services Central/WB M/E	Compierchio,Joseph M
		466	Field Services Central Design	Krushin,Joseph L
		467	Field Services Central Metering	Charney,Thomas
		468	Field Services Central T/D	Compierchio,Joseph M
		469	Field Services Central M/E	Compierchio,Joseph M
	Northeast Region	470	Field Services Northeast	Collins,Ronald J
		451	Field Services NE/Scranton Design	Baumgardner, T L
		452	Field Services NE/Scranton Metering	Gorski,Francis
		453	Field Services NE/Scranton T/D	Collins,Ronald J
		454	Field Services NE/Scranton M/E	Collins,Ronald J
		471	Field Services NE/Pocono Design	Sucheski,Michael A
		473	Field Services NE/Pocono T/D	Collins,Ronald J
		474	Field Services NE/Pocono M/E	Collins,Ronald J
Field Services Generation	Field Services Generation	551	Generation	Yanek,John

PPL Electric Utilities Corporation

Exhibit JRS3

Docket No. R-00049255

PPL ELECTRIC UTILITIES CORPORATION
BUDGET ITEMS USED TO MONITOR EXPENDITURES

Wages and Employee Benefits
Employee Expenses
Vehicles & Equipment Use
Materials & Supplies
Printing & Office Supplies
Tree Trimming
Work by Outsiders
Services
Postage
Telephone & Leased Wires
Rents
Advertising
Uncollectible Accounts
Sustainable Energy Fund Exp.
Miscellaneous

PPL Electric Utilities Corporation

Exhibit JRS4

Docket No. R-00049255

PPL ELECTRIC UTILITIES CORPORATION

Budget-2004
(Thousands of Dollars)

	1st Q	2nd Q	3rd Q	4th Q	Total
Operating Revenues					
Electric Operations	$ 654,018	$ 536,409	$ 581,266	$ 597,548	$ 2,369,241
Gas Operations					
Wholesale & Energy Trading	39,208	36,275	33,903	37,108	146,494
Energy Related Businesses	143	143	143	143	572
Intercompany Sales					
Scenario adjustments					
Total Operating Revenues	**693,369**	**572,827**	**615,312**	**634,799**	**2,516,307**
Operating Expenses					
Electric Fuel					
Cost of Natural Gas & Propane					
Energy Purchases - External	52,792	51,063	49,555	52,888	206,298
Energy Purchases - Internal	*419,472*	*344,902*	*375,275*	*383,717*	*1,523,366*
Lease/Rent payments					
Other Operating Expenses - Direct	59,159	67,050	68,423	65,866	260,498
Other Operating Expenses - Intercompany	21,612	21,496	21,276	20,421	84,805
Total O&M Expense	80,771	88,546	89,699	86,287	345,303
Amort. of Deferred Debits/Credits	1,322	1,049	1,183	1,196	4,750
Depreciation	27,155	27,155	27,155	27,155	108,620
Taxes other than income	46,865	38,777	41,815	42,945	170,402
Energy Related Businesses	97	96	97	96	386
Total Operating Expenses	**628,474**	**551,588**	**584,779**	**594,284**	**2,359,125**
Income from Operations	**64,895**	**21,239**	**30,533**	**40,515**	**157,182**
Other Income and (Deductions)	869	869	869	870	3,477
Interest expense					
Long Term Debt	22,320	21,058	20,247	19,714	83,339
Preferred Security Dividends					
Short Term Debt & Other	1,524	1,693	1,681	2,301	7,199
Intercompany Interest					
AFUDC & Capitalized Interest	(364)	(363)	(364)	(363)	(1,454)
Total Interest Expense	23,480	22,388	21,564	21,652	89,084
Income before Income Taxes	**42,284**	**(280)**	**9,838**	**19,733**	**71,575**
Income Taxes					
Provision-Federal	5,409	(7,116)	(4,146)	(660)	(6,513)
-State	3,818	(126)	809	1,911	6,412
Deferred Income Taxes	6,542	6,542	6,542	6,542	26,168
Total Income Taxes	15,769	(700)	3,205	7,793	26,067
Minority Interest					
Income Before Extraordinary Item	**26,515**	**420**	**6,633**	**11,940**	**45,508**
Extraordinary Item, net of income taxes					
Net Income	**26,515**	**420**	**6,633**	**11,940**	**45,508**
Preferred Stock Dividend Requirements	612	611	612	611	2,446
Earnings Available for Common Stock	$ 25,903	$ (191)	$ 6,021	$ 11,329	$ 43,062

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

PPL Electric Utilities Corporation

Statement No. 3

Direct Testimony of David R. Woodruff

Direct Testimony of David R. Woodruff

Q. Please state your full name and business address.

A. David R. Woodruff, 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") in the Asset Management Department as Manager – Load Analysis.

Q. What are your duties as Manager – Load Analysis?

A. I am responsible for the overall direction of the functions of the Load Analysis Section within the Asset Financial Evaluation section of the Asset Management Department. In this capacity, I direct the forecasting of customer energy sales, revenues, and peak demands. In addition, I oversee the collection of load research data and the development of historical and forecasted customer and rate class hourly demands. This includes the forecasting of hourly demands for the PPL System within PJM and the Provider of Last Resort ("POLR") used for scheduling PPL Electric's daily load requirements.

Q. What is your education background?

A. I graduated from The Pennsylvania State University in 1980 with a Bachelor of Science in Civil Engineering; and from Drexel University in 1998 with a Master of Science in Engineering Management. I am a licensed Professional Engineer in the State of Pennsylvania.

Q. Please describe your professional experience.

A. I was employed by PPL Corporation in 1980 as an Engineer in the Power Plant Engineering Department. My responsibilities were to design modifications to PPL fossil and hydro power plants. In 1988, I assumed the position of Project Engineer in the Fuel Planning Section of the Fossil Fuels Department. My responsibilities were fuel price forecasting and analytical support for Fuel Operations. In 1995, I assumed the position of Fuel Procurement Agent within the Fuel Procurement Section of the Fossil Fuels Department. My responsibilities were the procurement of fuel (Anthracite coal, bituminous coal, petroleum coke) for the fossil power plants. In 1996, I assumed the position of Senior Consultant in the IS Consulting Section of the Information Services Department. My responsibilities were the negotiation of computer hardware contracts, and procurement of computer equipment. In 1998, I was named acting Supervisor within the Consulting Section. In 1998, I assumed the position of Senior Forecaster in the Load Analysis Section. My responsibilities included the development and implementation of new hourly forecasting models to meet the POLR requirements of PPL Electric, the implementation of new monthly sales forecasting models, and forecasting of Alternate Supplier loads. In 2001, I assumed my current position.

Q. Mr. Woodruff, what is the purpose of your testimony?

A. The purpose of my testimony is as follows:

- To explain the development of the Company's forecast of customer sales, revenues, and peak demands;
- To sponsor and explain the annualization of sales and base rate revenues as summarized on Schedules D-3 of Exhibit Historic 1 and Exhibit Future 1; and
- To explain the derivation of customer load data used to develop the demand allocators employed by Joseph M. Kleha in his cost of service studies.

Q. Have you prepared any exhibits to accompany your direct testimony?

A. Yes. I an sponsoring Exhibit DRW1 which consists of 6 pages. The first page sets forth the Company's forecast of annual sales by customer class for the period 2004-2013. Page 2 of Exhibit DRW1 provides aggregate peak load data for the same period. Pages 3 and 4 of Exhibit DRW1 show the 2003 Annualization by rate schedule of distribution and transmission revenues, and pages 5 and 6 of Exhibit DRW1 show the Annualization details for the future test year.

Q. Please describe the development of the sales forecast contained in Exhibit DRW1.

A. The sales forecast is developed for the Residential, Commercial, Industrial, and Other customer classes. The Residential customer class is further segmented into Electrically Heated Home (EHH) and General Residential Service (GRS), and Industrial is segmented by industry. These customer class forecasts were developed from models using regression analysis of historical sales data, economic data, and weather data. Historical and forecasted economic data for the Commonwealth of Pennsylvania is obtained from Economy.com. The weather data is obtained from the following airports: Lehigh Valley International, Harrisburg (Middletown), Wilkes-Barre/Scranton (Avoca), and Williamsport. Forecasted weather is based on calculating normal weather on a heating degree-day (HDD) and cooling degree-day (CDD) basis for the past 20 years. The models use these inputs to generate a monthly sales forecast for each customer class.

Q. How was the sales forecast set forth in Exhibit DRW1 used in the rate filing?

A. The sales forecast was used to develop projected future test year sales and revenues.

Q. How did you develop the peak load forecast set forth on Page 2 of Exhibit DRW1?

Q. The peak load forecast shown on Page 2 of Exhibit DRW1 is a function of historical weather-normalized peaks. Each year, as required by PJM, PPL determines the weather-normalized summer and winter peaks. These peaks are based on a regression of actual daily unrestricted peaks against the corresponding weather conditions for the respective season. The point on the regression line corresponding to the 20-year normal weather is the weather-normalized peak for that season.

The forecasted peaks are developed for both the summer and winter season using two separate regression models. These models estimate the relationship between the historical seasonal peaks to annual energy sales and various economic drivers. This analysis uses 20 years of history, which results in the forecasted seasonal peaks for the subsequent years. The other months of the year are then estimated, using the historical percentage of the seasonal peak for the appropriate month.

Q. Please describe the development of the revenue forecast used in Schedule D-3 of Exhibit Future 1.

A. The first step in this process is converting the forecast of sales by customer class to a forecast of sales by rate schedule. This conversion is done by applying historic billing factors which allocates the customer class sales to the various rate schedules. These factors are annual factors based on revenue month billing data from the most recent revenue year. The revenue forecast is developed by applying the forecast of sales by rate to the appropriate rate schedule pricing as detailed in the published General Tariff of PPL Electric.

Q. Schedules D-3 of Exhibit Historic 1 and Future 1 reflect annualizations of sales and base rate revenues for the historic and future test years. Please explain how those adjustments were developed.

A. The annualization adjustment of sales and base rate revenues for the historic year ended December 31, 2003 has two components. One accounts for changes in the number of customers over the test year, and the second accounts for changes in usage. The adjustment for the change in number of customers as reported for the year by rate class was determined as follows. The change in customers from December 31, 2002 to December 31, 2003 was computed for each rate class. One-half of that change was assigned class by class and then multiplied by the average annual KWH usage per customer to obtain the sales adjustment (KWH) associated with new customers entering the rate class. The average unit base rate for each rate class was applied to the resulting KWH figures to obtain the base rate revenue adjustments for all rate components.

The second adjustment recognizes changing KWH usage levels by existing customers and was determined as follows. The average change over the past three years in average annual usage for each class was computed. One-half of the change in average use was multiplied by the year-end number of customers for each rate class to obtain the KWH adjustment. The incremental base rate for each rate class was applied to this KWH adjustment to obtain the base rate revenue adjustment. Details of the 2003 Annualization are shown on Page 3 or Exhibit DRW1. The annualization of future test year sales and revenues consisted of similar adjustments for changes in the numbers of customers and customer usage. The details of the future test year annualization are shown on Page 4 of Exhibit DRW1.

Q. Please explain the source of the customer load data used to develop the customer class demand allocators employed in the Company's cost of service study.

A. PPL Electric continuously collects load data in 15 minute intervals through recording demand meters on sample locations for customers in the residential, GS-1, GS-3, LP-4, and GH classes and for all customers on Rate Schedules LP-5, LP-6, interruptible, and all FERC jurisdictional customers. For the rate classes represented by samples of load data, the sample data are extrapolated to determine hourly demands for the entire rate class. These rate class hourly demands are used to determine the annual rate class maximum demands. The hourly demands are also used to determine the contribution of each rate class to each of the twelve monthly peaks during the historic test year. These are averaged to calculate the coincident peak demands for that class.

For the future test year, the rate class average demand coincident to the monthly system peak demand and the annual rate class maximum demands were projected by analyzing total rate class demand data from January 1994 to December 2002. The respective rate class historical values were analyzed using a Box-Jenkins modeling technique (also known as ARIMA modeling).

Q. Does this conclude your testimony?

A. Yes it does.

PPL ELECTRIC UTILITIES CORPORATION

Exhibit DRW 1
Annual Retail Sales by Customer Class
Annual Net Energy, Seasonal Peaks and Load Factor
2003 Annualization of Distribution Revenues
2003 Annualization of Transmission Revenues
2004 Annualization of Distribution Revenues
2004 Annualization of Transmission Revenues

Witness: David R. Woodruff
Docket No. R-00049255

PPL ELECTRIC UTILITIES CORPORATION

Exhibit DRW1

Annual Retail Sales by Customer Class
Annual Net Energy, Seasonal Peaks, and Load Factor
2003 Annualization of Distribution Revenues
2003 Annualization of Transmission Revenues
2004 Annualization of Distribution Revenues
2004 Annualization of Transmission Revenues

Witness: David R. Woodruff

PPL Electric Utilities
Annual Retail Sales by Customer Class

Sales (millions of kwh)	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Residential Electric Heat (EHH)	6,705.5	6,460.2	6,563.2	6,659.1	6,760.9	6,867.1	6,974.0	7,082.7	7,196.3	7,311.5	7,420.4	7,531.8
Residenial General Service (GRS)	5,934.3	6,805.9	6,744.7	6,860.3	6,981.8	7,109.6	7,239.1	7,371.9	7,512.1	7,655.5	7,793.5	7,936.8
Residential	12,639.8	13,266.1	13,307.9	13,519.4	13,742.7	13,976.7	14,213.1	14,454.7	14,708.4	14,967.0	15,213.9	15,468.7
Commercial	12,041.8	12,273.5	13,275.2	13,600.9	13,954.7	14,285.5	14,631.3	14,980.6	15,329.4	15,671.3	15,984.5	16,284.1
Industrial	9,852.7	9,646.2	9,937.9	10,035.1	10,154.6	10,256.2	10,345.8	10,431.3	10,512.5	10,591.0	10,661.7	10,725.5
Other	169.0	153.5	168.1	168.8	169.5	170.2	170.8	171.4	172.1	172.6	173.0	173.4
Total	34,703.3	35,339.3	36,689.1	37,324.2	38,021.5	38,688.6	39,361.0	40,038.0	40,722.4	41,401.9	42,033.1	42,651.7

Year-To-Year Change (millions of kwh)	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Residential Electric Heat (EHH)		(245.3)	103.0	95.9	101.7	106.2	106.9	108.7	113.6	115.2	108.9	111.4
Residenial General Service (GRS)		871.6	(61.2)	115.6	121.6	127.8	129.5	132.8	140.1	143.4	138.0	143.3
Residential		626.3	41.8	211.5	223.3	234.0	236.4	241.6	253.8	258.6	246.9	254.7
Commercial		231.6	1,001.7	325.7	353.8	330.8	345.8	349.3	348.8	341.9	313.2	299.6
Industrial		(206.5)	291.7	97.2	119.5	101.6	89.6	85.5	81.2	78.5	70.7	63.8
Other		(15.5)	14.6	0.7	0.7	0.7	0.6	0.6	0.7	0.5	0.4	0.4
Total		635.9	1,349.8	635.1	697.3	667.1	672.4	677.0	684.5	679.5	631.2	618.5

Year-To-Year Change (%)	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Residential Electric Heat (EHH)		-3.66%	1.59%	1.46%	1.53%	1.57%	1.56%	1.56%	1.60%	1.60%	1.49%	1.50%
Residenial General Service (GRS)		14.69%	-0.90%	1.71%	1.77%	1.83%	1.82%	1.83%	1.90%	1.91%	1.80%	1.84%
Residential		4.95%	0.32%	1.59%	1.65%	1.70%	1.69%	1.70%	1.76%	1.76%	1.65%	1.67%
Commercial		1.92%	8.16%	2.45%	2.60%	2.37%	2.42%	2.39%	2.33%	2.23%	2.00%	1.87%
Industrial		-2.10%	3.02%	0.98%	1.19%	1.00%	0.87%	0.83%	0.78%	0.75%	0.67%	0.60%
Other		-9.17%	9.51%	0.42%	0.41%	0.41%	0.35%	0.35%	0.41%	0.29%	0.23%	0.23%
Total		1.83%	3.82%	1.73%	1.87%	1.75%	1.74%	1.72%	1.71%	1.67%	1.52%	1.47%

Note: Sales values for 2002 and 2003 are actual. Sales for 2004 through 2013 are forecast.

PPL Electric Utilities
Annual Net Energy, Seasonal Peaks, and Load Factor

Year	Net Energy Sales Level (GWH)	Net Energy Generation Level (GWH)	Peaks Summer (MW)	Peaks Winter (MW)	Load Factor (%)
2004	37,924	40,657	6,951	7,027	65.87
2005	38,570	41,351	7,086	7,195	65.61
2006	39,282	42,116	7,239	7,299	65.87
2007	39,969	42,852	7,377	7,405	66.06
2008	40,659	43,590	7,521	7,509	65.98
2009	41,352	44,333	7,666	7,613	66.02
2010	42,053	45,085	7,812	7,717	65.88
2011	42,749	45,831	7,954	7,824	65.78
2012	43,397	46,524	8,084	7,924	65.52
2013	44,032	47,207	8,208	8,019	65.65

PPL Electric Utilities
2003 Annualization of Distribution Revenue

(1) Rate	(2) Revenue $	(3) Sales kWh	(4) (2) / (3) Average Price $/kWh	(5) (25) on "KWH" Sales Adjustment - Customer Usage kWh	(6) (4) * (5) Customer Usage Revenue $	(7) Incremental Price $/kWh	(8) (26) on "KWH" Sales Adjustment - Customer Growth kWh	(9) (7) * (8) Customer Growth Revenue $	(10) (5) + (8) Total Sales Adjustment kWh	(11) (6) + (9) Total Revenue Adjustment $
RS	$ 292,103,898	12,850,444,097	$ 0.0227	160,340,739	$ 3,644,711	$ 0.0148	102,731,126	$ 1,521,790	263,071,865	$ 5,166,501
RTS	$ 3,308,318	402,850,844	$ 0.0082	4,200,750	$ 34,498	$ 0.0005	1,090,618	$ 534	5,291,369	$ 35,032
RTD	$ 114,731	5,197,702	$ 0.0221	62,632	$ 1,383	$ 0.0139	157,506	$ 2,189	220,138	$ 3,572
GS-1	$ 55,672,108	1,877,528,074	$ 0.0297	15,428,216	$ 457,475	$ 0.0165	19,519,778	$ 321,990	34,947,994	$ 779,465
GS-3	$ 77,205,208	8,056,614,803	$ 0.0096	11,204,119	$ 107,367	$ 0.0041	107,292,882	$ 438,344	118,497,001	$ 545,711
LP-4	$ 21,043,893	5,418,356,192	$ 0.0039	(8,582,152)	$ (33,331)	$ 0.0032	57,337,103	$ 185,895	48,754,951	$ 152,564
ISP	$ 1,608,596	371,106,783	$ 0.0043	(9,579,731)	$ (41,524)	$ 0.0029	(11,971,187)	$ (35,130)	(21,550,917)	$ (76,654)
LP-5	$ 1,723,603	3,210,106,177	$ 0.0005	(35,162,942)	$ (18,880)	$ 0.0004	32,101,062	$ 12,821	(3,061,880)	$ (6,059)
IST	$ 1,865,255	1,877,775,648	$ 0.0010	9,631,595	$ 9,567	$ 0.0011	(134,126,832)	$ (149,823)	(124,495,237)	$ (140,256)
L5S	$ 28,445	6,963,000	$ 0.0041	(98,625)	$ (403)	$ 0.0002	(580,250)	$ (88)	(678,875)	$ (491)
LP-6	$ 240,071	439,554,000	$ 0.0005	(6,782,148)	$ (3,704)	$ 0.0005	109,888,500	$ 57,663	103,106,352	$ 53,959
LPEP	$ 366,402	59,921,900	$ 0.0061	(7,086,350)	$ (43,331)	$ 0.0020	-	$ -	(7,086,350)	$ (43,331)
ISM	$ 652,706	215,130,588	$ 0.0030	(31,873,304)	$ (96,704)	$ 0.0004	-	$ -	(31,873,304)	$ (96,704)
IS-1	$ 32,723	1,725,020	$ 0.0190	(268,263)	$ (5,089)	$ 0.0037	-	$ -	(268,263)	$ (5,089)
BL	$ 213,186	6,160,146	$ 0.0346	(487,446)	$ (16,869)	$ 0.0343	81,055	$ 2,778	(406,392)	$ (14,092)
SA	$ 3,186,502	23,724,139	$ 0.1343	-	$ -	$ 0.1343	-	$ -	-	$ -
SM	$ 712,626	5,043,104	$ 0.1413	(217,138)	$ (30,683)	$ 0.1413	(71,365)	$ (10,084)	(288,503)	$ (40,767)
SHS	$ 12,864,765	62,233,928	$ 0.2067	(1,328,300)	$ (274,581)	$ 0.2067	344,786	$ 71,273	(983,514)	$ (203,308)
SE	$ 718,559	19,506,269	$ 0.0368	735,743	$ 27,103	$ 0.0368	(123,457)	$ (4,548)	612,286	$ 22,555
TS	$ 23,780	380,088	$ 0.0626	10,338	$ 647	$ 0.0626	(21,116)	$ (1,321)	(10,778)	$ (674)
SI-1	$ 15,774	93,790	$ 0.1682	(11,837)	$ (1,991)	$ 0.1682	-	$ -	(11,837)	$ (1,991)
GH-1	$ 3,890,184	235,468,388	$ 0.0165	(14,438,565)	$ (238,540)	$ 0.0087	(248,647)	$ (2,171)	(14,687,212)	$ (240,711)
GH-2	$ 1,030,834	71,152,109	$ 0.0145	442,790	$ 6,415	$ 0.0076	(259,364)	$ (1,983)	183,426	$ 4,432
Total	**$ 478,622,166**	**35,217,036,789**		**86,140,120**	**$ 3,483,535**		**283,142,199**	**$ 2,410,128**	**369,282,318**	**$ 5,893,663**

Exhibit DRW1
David R. Woodruff
Page 3 of 6

PPL Electric Utilities
2003 Annualization of Transmission Revenues

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
			(2) / (3)	(25) on "KWH"	(4) * (5)		(26) on "KWH"	(7) * (8)	(5) + (8)	(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	$ 48,368,383	12,850,444,097	$ 0.0038	160,340,739	$ 603,514	$ 0.0038	102,731,126	$ 386,697	263,071,865	$ 990,211
RTS	$ 479,080	402,850,844	$ 0.0012	4,200,750	$ 4,996	$ 0.0012	1,090,618	$ 1,297	5,291,369	$ 6,293
RTD	$ 19,595	5,197,702	$ 0.0038	62,632	$ 236	$ 0.0038	157,506	$ 594	220,138	$ 830
GS-1	$ 10,727,775	1,877,528,074	$ 0.0057	15,428,216	$ 88,153	$ 0.0056	19,519,778	$ 110,060	34,947,994	$ 198,213
GS-3	$ 33,247,241	8,056,614,803	$ 0.0041	11,204,119	$ 46,236	$ 0.0036	107,292,882	$ 382,050	118,497,001	$ 428,286
LP-4	$ 17,869,868	5,418,356,192	$ 0.0033	(8,582,152)	$ (28,304)	$ 0.0039	57,337,103	$ 222,488	48,754,951	$ 194,184
ISP	$ 1,343,013	371,106,783	$ 0.0036	(9,579,731)	$ (34,668)	$ 0.0035	(11,971,187)	$ (42,333)	(21,550,917)	$ (77,001)
LP-5	$ 9,083,662	3,210,106,177	$ 0.0028	(35,162,942)	$ (99,501)	$ 0.0031	32,101,062	$ 99,305	(3,061,880)	$ (196)
IST	$ 6,754,058	1,877,775,648	$ 0.0036	9,631,595	$ 34,643	$ 0.0035	(134,126,832)	$ (471,753)	(124,495,237)	$ (437,110)
L5S	$ 21,168	6,963,000	$ 0.0030	(98,625)	$ (300)	$ 0.0030	(580,250)	$ (1,764)	(678,875)	$ (2,064)
LP-6	$ 1,336,244	439,554,000	$ 0.0030	(6,782,148)	$ (20,618)	$ 0.0030	109,888,500	$ 334,061	103,106,352	$ 313,443
LPEP	$ (40,009)	59,921,900	$ (0.0007)	(7,086,350)	$ 4,731	$ 0.0018	-	$ -	(7,086,350)	$ 4,731
ISM	$ 486,951	215,130,588	$ 0.0023	(31,873,304)	$ (72,146)	$ 0.0023	-	$ -	(31,873,304)	$ (72,146)
IS-1	$ 7,970	1,725,020	$ 0.0046	(268,263)	$ (1,239)	$ 0.0046	-	$ -	(268,263)	$ (1,239)
BL	$ 35,640	6,160,146	$ 0.0058	(487,446)	$ (2,820)	$ 0.0058	81,055	$ 466	(406,392)	$ (2,354)
SA	$ 81,788	23,724,139	$ 0.0034	-	$ -	$ 0.0034	-	$ -	-	$ -
SM	$ 15,653	5,043,104	$ 0.0031	(217,138)	$ (674)	$ 0.0031	(71,365)	$ (222)	(288,503)	$ (895)
SHS	$ 196,069	62,233,928	$ 0.0032	(1,328,300)	$ (4,185)	$ 0.0032	344,786	$ 1,086	(983,514)	$ (3,099)
SE	$ 61,554	19,506,269	$ 0.0032	735,743	$ 2,322	$ 0.0032	(123,457)	$ (390)	612,286	$ 1,932
TS	$ 1,209	380,088	$ 0.0032	10,338	$ 33	$ 0.0032	(21,116)	$ (67)	(10,778)	$ (34)
SI-1	$ 298	93,790	$ 0.0032	(11,837)	$ (38)	$ 0.0032	-	$ -	(11,837)	$ (38)
GH-1	$ 1,002,193	235,468,388	$ 0.0043	(14,438,565)	$ (61,453)	$ 0.0046	(248,647)	$ (1,139)	(14,687,212)	$ (62,592)
GH-2	$ 326,584	71,152,109	$ 0.0046	442,790	$ 2,032	$ 0.0046	(259,364)	$ (1,183)	183,426	$ 849
Total	**$ 131,425,986**	**35,217,036,789**		**86,140,120**	**$ 460,951**		**283,142,199**	**$ 1,019,253**	**369,282,318**	**$ 1,480,204**

PPL Electric Utilities
2004 Annualization of Distribution Revenues

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
			(2) / (3)	(25) on "KWH"	(4) * (5)		(26) on "KWH"	(7) * (8)	(5) + (8)	(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	$ 296,856,394	12,894,610,000	$ 0.0230	111,373,684	$ 2,564,016	$ 0.0170	11,115,956	$ 188,935	122,489,640	$ 2,752,951
RTS	$ 3,472,873	399,999,000	$ 0.0087	1,398,658	$ 12,143	$ 0.0017	5,263,887	$ 8,754	6,662,546	$ 20,897
RTD	$ 118,811	5,295,000	$ 0.0224	32,794	$ 736	$ 0.0150	9,662	$ 145	42,457	$ 881
GS-1	$ 60,536,043	2,060,700,000	$ 0.0294	36,785,522	$ 1,080,628	$ 0.0095	(11,393,142)	$ (108,577)	25,392,380	$ 972,051
GS-3	$ 83,162,768	8,779,502,000	$ 0.0095	100,650,653	$ 953,401	$ 0.0046	(16,421,027)	$ (74,872)	84,229,626	$ 878,529
LP-4	$ 21,621,705	5,588,425,000	$ 0.0039	76,252,304	$ 295,021	$ 0.0028	(250,366,386)	$ (709,376)	(174,114,081)	$ (414,354)
ISP	$ 1,737,068	404,108,000	$ 0.0043	(598,960)	$ (2,575)	$ 0.0022	12,245,697	$ 27,179	11,646,737	$ 24,604
LP-5	$ 1,753,662	3,348,588,000	$ 0.0005	8,255,499	$ 4,323	$ 0.0010	(119,592,429)	$ (119,362)	(111,336,930)	$ (115,039)
IST	$ 1,697,254	1,944,598,000	$ 0.0009	2,510,900	$ 2,192	$ (0.0001)	156,822,419	$ (13,030)	159,333,320	$ (10,839)
L5S	$ 36,037	7,024,000	$ 0.0051	234,000	$ 1,201	$ 0.0051	-	$ -	234,000	$ 1,201
LP-6	$ 279,835	511,847,000	$ 0.0005	(3,544,706)	$ (1,938)	$ 0.0002	-	$ -	(3,544,706)	$ (1,938)
LPEP	$ 309,600	72,000,000	$ 0.0043	(7,661,167)	$ (32,943)	$ -	-	$ -	(7,661,167)	$ (32,943)
ISM	$ 653,916	242,640,000	$ 0.0027	(15,201,060)	$ (40,967)	$ -	-	$ -	(15,201,060)	$ (40,967)
IS-1	$ 54,648	2,120,000	$ 0.0258	(156,390)	$ (4,031)	$ (0.0013)	-	$ -	(156,390)	$ (4,031)
BL	$ 219,314	6,360,000	$ 0.0345	(13,256)	$ (457)	$ -	(212,000)	$ -	(225,256)	$ (457)
SA	$ 3,120,447	23,518,000	$ 0.1327	-	$ -	$ 0.1327	-	$ -	-	$ -
SM	$ 716,987	5,141,000	$ 0.1395	(142,234)	$ (19,837)	$ 0.1395	93,473	$ 13,036	(48,762)	$ (6,801)
SHS	$ 12,900,899	63,342,000	$ 0.2037	(447,860)	$ (91,216)	$ 0.2037	(87,975)	$ (17,918)	(535,835)	$ (109,134)
SE	$ 725,632	19,699,000	$ 0.0368	536,563	$ 19,765	$ 0.0368	123,119	$ 4,535	659,682	$ 24,300
TS	$ 22,076	353,000	$ 0.0625	(14,693)	$ (919)	$ 0.0625	17,650	$ 1,104	2,957	$ 185
SI-1	$ 15,775	95,000	$ 0.1661	(3,787)	$ (629)	$ 0.1661	-	$ -	(3,787)	$ (629)
GH-1	$ 5,007,989	364,833,000	$ 0.0137	7,620,811	$ 104,609	$ 0.0087	8,553,679	$ 74,804	16,174,490	$ 179,413
GH-2	$ 1,142,642	73,455,000	$ 0.0156	538,733	$ 8,380	$ 0.0011	1,726,322	$ 1,974	2,265,055	$ 10,354
Total	**$ 496,162,375**	**36,818,252,000**		**318,406,009**	**$ 4,850,905**		**(202,101,093)**	**$ (722,670)**	**116,304,916**	**$ 4,128,235**

PPL Electric Utilities
2004 Annualization of Transmission Revenues

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
			(2) / (3)	(25) on "KWH"	(4) * (5)		(26) on "KWH"	(7) * (8)	(5) + (8)	(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	48,512,730	12,894,610,000	0.0038	111,373,684	419,016	0.0038	11,115,956	41,821	122,489,640	460,837
RTS	475,522	399,999,000	0.0012	1,398,658	1,663	0.0012	5,263,887	6,258	6,662,546	7,921
RTD	19,962	5,295,000	0.0038	32,794	124	0.0038	9,662	36	42,457	160
GS-1	11,664,590	2,060,700,000	0.0057	36,785,522	208,224	0.0057	(11,393,142)	(65,009)	25,392,380	143,215
GS-3	37,948,721	8,779,502,000	0.0043	100,650,653	435,055	0.0043	(16,421,027)	(71,213)	84,229,626	363,841
LP-4	19,599,130	5,588,425,000	0.0035	76,252,304	267,424	0.0035	(250,366,386)	(877,502)	(174,114,081)	(610,078)
ISP	1,458,829	404,108,000	0.0036	(598,960)	(2,162)	0.0036	12,245,697	44,207	11,646,737	42,045
LP-5	9,670,703	3,348,588,000	0.0029	8,255,499	23,842	0.0029	(119,592,429)	(345,359)	(111,336,930)	(321,518)
IST	6,942,215	1,944,598,000	0.0036	2,510,900	8,964	0.0036	156,822,419	559,848	159,333,320	568,812
L5S	21,352	7,024,000	0.0030	234,000	711	0.0030	-	-	234,000	711
LP-6	1,556,013	511,847,000	0.0030	(3,544,706)	(10,776)	0.0030	-	-	(3,544,706)	(10,776)
LPEP	38,160	72,000,000	0.0005	(7,661,167)	(4,060)	-	-	-	(7,661,167)	(4,060)
ISM	353,040	242,640,000	0.0015	(15,201,060)	(22,117)	-	-	-	(15,201,060)	(22,117)
IS-1	9,794	2,120,000	0.0046	(156,390)	(722)	0.0046	-	-	(156,390)	(722)
BL	36,888	6,360,000	0.0058	(13,256)	(77)	-	(212,000)	-	(225,256)	(77)
SA	80,116	23,518,000	0.0034	-	-	0.0034	-	-	-	-
SM	16,055	5,141,000	0.0031	(142,234)	(444)	0.0031	93,473	292	(48,762)	(152)
SHS	198,094	63,342,000	0.0031	(447,860)	(1,401)	0.0031	(87,975)	(275)	(535,835)	(1,676)
SE	62,124	19,699,000	0.0032	536,563	1,692	0.0032	123,119	388	659,682	2,080
TS	1,119	353,000	0.0032	(14,693)	(47)	0.0032	17,650	56	2,957	9
SI-1	299	95,000	0.0031	(3,787)	(12)	0.0031	-	-	(3,787)	(12)
GH-1	1,480,301	364,833,000	0.0041	7,620,811	30,921	0.0040	8,553,679	34,161	16,174,490	65,083
GH-2	334,567	73,455,000	0.0046	538,733	2,454	0.0046	1,726,322	7,887	2,265,055	10,341
Total	**140,480,324**	**36,818,252,000**		**318,406,009**	**1,358,270**		**(202,101,093)**	**(664,404)**	**116,304,916**	**693,867**

DOCUMENT

DOCKETED
AUG 25 2004

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

RECEIVED
AUG 24 2004
PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

Docket No. R-00049255

PPL Electric Utilities Corporation

Statement No. 4

Direct 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. Please describe your primary responsibilities in that position.

A. As Manager – Regulatory Strategy, I am responsible for assisting in the development of long-term strategy, goals and objectives; providing regulatory insights into the development and implementation of business strategies; and leading the development of responses to legislative, regulatory, and political issues.

Q. What is your educational background?

A. I graduated from Stevens Institute of Technology in Hoboken, New Jersey in 1973 with a Bachelor of Engineering degree in Mechanical Engineering. I have completed courses in Business Administration at Muhlenberg College in Allentown, Pennsylvania.

Q. Are you a registered Professional Engineer?

A. Yes. I have been a registered Professional Engineer in the Commonwealth of Pennsylvania since 1977. My registration number is PE-026733-E.

Q. Please describe your professional experience.

A. I joined the Mechanical Engineering Department of PPL Electric's predecessor Pennsylvania Power and Light ("PP&L") in 1973 as an Engineer-Level I working on studies related to PP&L's generating plants. In 1974, the engineering functions were restructured, and I became a member of the Power Plant Engineering Department. In 1975, I was promoted to the position of Engineer-Level II, and in 1978 to the position of Project Engineer within that department. Later in 1978, I transferred to the System Planning Department, and in 1981, I was promoted to the position of Senior Project Engineer. In both of those positions I was responsible for the development of plans related to maintaining and upgrading PP&L's existing fossil and hydro generating plants. In 1984, I was promoted to the position of Manager-Generation Development Planning within the System Planning Department with responsibility for the portion of PP&L's capital budget related to existing fossil and hydro generating plants as well as overall administrative responsibility for PP&L's capital budget. I was also, in that position, PP&L's coordinator for activities related to compliance with the 1990 Federal Clean Air Act Amendments. In December 1994, my title changed to Manager-Integrated Resource Planning, but the duties remained relatively the same. In April 1996, I became the Manager-Resource Planning and Pricing. In this capacity, I supervised the development of integrated resource plans, the administration of PP&L's responsibilities regarding non-utility generation, the development of PP&L's capital budget and the development and administration of PP&L's tariff for electric service. As the Competition Act was passed in Pennsylvania in late 1996 and the pace of industry restructuring accelerated, my duties in this position changed rapidly. The generation and capital budgeting functions were moved to other organizations and, ultimately, to different affiliates. In their place I took on new duties related to load analysis and coordination of activities within the regulated distribution entity to implement customer choice. In August 2001 I assumed my current position.

Q. Have you previously testified as a witness before the Pennsylvania Public Utility Commission ("PUC") or the Federal Energy Regulatory Commission ("FERC")?

A. Yes. I have testified before the PUC on numerous occasions including the Company's restructuring proceeding (Docket No. R-00973954), a base rate proceeding (Docket No. R-00943271), proceedings regarding non-utility generators, and proceedings arising from customer complaints.

At the FERC, I have testified in regard to PP&L's compliance plans under the 1990 Clean Air Act Amendments (Docket No. ER95-1267), and in regard to PP&L's investment in generating plants to serve its wholesale customers (Docket No. SC97-1-000).

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

A. My testimony addresses the following:

1. The Company's construction budget which provided the basis for estimates of electric plant additions and retirements reflected in the future test year.
2. The Company's response to Regulation II-B-1 and the Company's claim for land held for future use.
3. The Company's Automated Meter Reading system.

4. The Company's request to amortize and recover from customers costs associated with employee displacements that resulted from the installation of the Automated Meter Reading System.
5. The Company's demand side response programs.
6. Principles and objectives that guided the allocation of costs and rate design.
7. The pass through of FERC-approved transmission charges.
8. The Company's proposal to institute a Distribution System Improvement Charge.
9. The Company's request to amortize and recover from customers costs associated with Hurricane Isabel.

Q. What Exhibits are you sponsoring in this proceeding?

A. I am sponsoring Exhibit DAK1 and I am also responsible for portions of the information supplied in Schedule D-2 of Exhibit Future-1. In addition, I am responsible for and will sponsor the Company's response to Commission Regulation II-B-1.

Additions to Rate Base

Q. Please describe Exhibit DAK1.

A. Exhibit DAK1 is a table that summarizes portions of PPL Corporation's 2004-2008 Capital Budget that relate to the capital spending needs of PPL Electric. At PPL Corporation, a capital budget is prepared annually to identify the capital requirements of the corporation and to establish a basis for financial and manpower planning. Each of the corporation's business lines is responsible for identifying, evaluating, and approving projects for inclusion in its capital budget, and then forwarding all data to the Financial Department where the Capital Budget for PPL Corporation is reviewed and consolidated.

Q. Please describe the major headings listed on Exhibit DAK1.

A. The major headings on Exhibit DAK1 are "Electric Utilities" and "Facilities Management". The section headed "Electric Utilities" summarizes capital requirements related to the distribution and transmission systems. The section headed "Facilities Management" summarizes capital requirements related to service centers, crew quarters, and office buildings. Supporting the annual amounts shown on Exhibit DAK1 are lists of projects, schedules for projects, and estimates of project costs and those lists, schedules, and estimates provide the detailed information that is the basis of the estimates of property additions and retirements that appear in the Company's response to Regulation V-A-3.

Q. Please describe the categories of expenditures listed in the section of Exhibit DAK1 headed "Electric Utilities".

A. The categories listed in this section and a description of each is as follows:

1. "Provide Electric Service" includes projects to install new service for residential, commercial, and industrial customers (including service upgrades for existing customers to serve additional load), street lighting additions and modernization, and purchases of distribution transformers for near-term use that are considered to be in service at the time of receipt. Work in this category is a function of customer requests. Forecasts of capital

requirements are based on forecasted economic conditions and projected numbers of new customers.

2. "Upgrade System Facilities" includes specific projects required to ensure and enhance system capacity and reliability. Projects are driven by forecasts of load growth and identified as a result of engineering studies that simulate system loadings under a variety of conditions. Also included in this category are funds for relocations due to highway improvements or other rights-of-way interferences. Forecasts of capital requirements for these last two items are based on recent spending history.

3. "Assure System Reliability" includes funding for the replacement of deteriorated, obsolete, or failed equipment. Work in this category is a function of identifying a need as the result of inspection, testing, scheduled replacement, or failure. Forecasts of capital requirements reflect inspection and testing plans, the age of equipment, and previously observed conditions.

4. "Revenue Cycle Service" includes electric meters for new services. Forecasts of capital requirements are based on the forecast of new customers.

5. "Automated Meter Reading" is the capital requirement associated with PPL Electric's program to replace existing meters with new and retrofitted meters and communication infrastructure that permits the meters to be read remotely. This program is described in detail later in my testimony.

6. "Other" reflects miscellaneous items such as office furniture, tools and equipment, and site acquisitions. Forecasts of capital requirements reflect recent history.

7. "Respond To Customer" includes small projects to resolve customer concerns related to outages, voltage complaints, street and area lighting problems, property damage, flickering lights, and other concerns. Forecasts of capital requirements are based on recent history.

Q Please describe the categories of expenditures listed in the section of Exhibit DAK1 headed "Facilities Management".

A. The categories listed in this section and a description of each is as follows:

1. "Replacement" includes projects to replace equipment that can no longer be maintained and is required for the continued operation of the building.

2. "Working Conditions/Safety" includes projects required to provide employees a safe and acceptable work environment.

3. "Environmental" includes projects required to meet state and local environmental regulations.

Forecasts of capital requirements in each category are based both on lists of specific identified needs and on recent history.

Q. Do the capital requirements set forth in Exhibit DAK1 and the associated property additions and retirements that appear in the Company's response to Regulation V-A-3 represent, in your opinion, a necessary investment in facilities by PPL Electric?

A. Yes. The capital requirements set forth in Exhibit DAK1 and the associated property additions and retirements that appear in the Company's response to Regulation V-A-3 are the result of careful engineering studies extending over many months, and of inspection and testing programs designed to monitor the condition of equipment and to anticipate the need to replace or upgrade it. This forecast of capital requirements reflects PPL Electric's best estimate of the facilities needed to provide reliable and economic delivery service both now and in the future. This forecast also considers the need to provide new and upgraded facilities which are necessary to maintain and, where appropriate, improve the efficiency of operating personnel. I believe that this forecast is reasonable and represents a prudent level of investment.

Land Held for Future Use

Q. Please explain PPL Electric's response to Regulation II-B-1.

A. Regulation II-B-1 tabulates sites and rights of way that the Company has acquired in anticipation of the construction of substations and lines. The response includes sites and rights-of-way for both transmission and distribution projects, however, the Company is seeking approval to include in rate base only those sites and rights-of-way associated with distribution projects. The total request associated with distribution plant is $2,212,678 consisting of $1,916,265 associated with distribution substations, $30,075 for distribution lines, and $266,338 associated with the installation of manholes and conduit for distribution lines. The response to Regulation II-B-1 lists 14 individual sites and rights of way, a description of the project each supports, the original date each was acquired, and the expected date of use for each.

In this proceeding, PPL Electric is making a claim for the $2,212,678 related to distribution plant held for future use. If this claim is not approved by the Commission, PPL Electric, in the alternative, is requesting 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 investment at the time such plant is placed into service.

Q. Why has PPL Electric acquired these sites and rights-of-way?

A. This land has been acquired because it was prudent to do so in support of the construction of distribution lines and substations that will be necessary to maintain reliability and accommodate new customers in the coming years.

The conditions that produce growth in electrical demand will also result in expansion of land occupancy. Residential, commercial, and other construction in an area may render it more costly or disruptive to the community to purchase land at the last possible moment. When a need can be identified, it is in the community interest to purchase land well in advance and record the land or right-of-way purchase. This provides the community with an awareness of PPL Electric's plans for the area.

Another consideration is that the necessary land or right-of-way may not be available when needed in the future, which may require significant changes in the overall plan for development of the distribution system; potentially making necessary development more costly to customers.

Allowance must be made for local planning discussions, for negotiations, for siting approval by the Commission and for possible condemnation proceedings. Needs must, therefore, be anticipated as far in advance as possible and the necessary steps taken to acquire essential land and easements.

Automated Meter Reading System

Q. Could you please provide an overview of PPL Electric's Automated Meter Reading System?

A. PPL Electric's Automated Meter Reading System ("AMR") involves the replacement of existing meters with new or retrofitted meters and communication infrastructure that permits the meters to be read remotely. Deployment began in the spring of 2002 with a small-scale test involving the meters of about 10,000 customers served by four specific substations in the Allentown/Bethlehem area. The purpose of this test was to confirm the technical capabilities of the equipment, develop and refine installation techniques, and establish procedures that would ultimately support the replacement of over 1.3 million meters with new or refurbished meters, the installation of communications equipment at over 300 substations, and the modification of meter data systems and billing systems to permit readings obtained in this fashion to be used for billing. Deployment is expected to be complete by September 30, 2004.

Q. Please describe how the AMR system functions.

A. PPL Electric's AMR system actually employs two different communications approaches to reading meters remotely. The first, deployed to almost all of the

1.3 million customers, relies on communications through the power lines themselves. This technology requires the installation of a communications link at each distribution substation. Communications signals are sent by conventional means (telephone line, fiber optic cable, or wireless) to the substation equipment that then places the signal on the appropriate distribution feeder. The signal travels on the power wave itself. Equipment in the meter is capable of reading this signal. Upon being signaled, the communications device in the meter causes a meter reading to be transmitted in the same fashion back to the substation. At the substation, the communications equipment puts the information back on the conventional communications system for transmission back to a communications server. In this approach, it is the communications server that directs activity. The server requests reads as a result of a prompt by the billing system (in the case of billing reads), a prompt by another meter information need (such as load research), or at the request of an individual user such as a Customer Service Representative ("CSR"). Upon receipt of a read, the communications server routes the response to the appropriate system. The meters themselves do not initiate communication. Logic built into the meters causes them to record readings at appropriate times, but those readings are not transmitted until the communication server requests that they be transmitted.

- The second communications approach is employed for customers who are served at higher voltages. In these instances, power line communication cannot survive the voltage transformation associated with metering so, in these cases, wireless communication is used to communicate with the meters. Here the communications server and the communications device in the meter communicate through existing cellular infrastructure. Upon being signaled, or at predefined intervals, the device causes a meter reading to be transmitted back to the cellular network and, through that network, back to the communications server. This second approach is deployed to about 6,200 customers.

Q. How much will the AMR installation cost once it is completed?

A. PPL Electric anticipates that the total capital cost of the AMR system will be about $160 million. Equipment placed in service through the end of 2003 is reflected in Historic Test Year Rate Base and equipment to be installed during 2004 is reflected in Future Test Year Rate Base.

Q. How do customers benefit from AMR?

A. Customers benefit from AMR in several ways. First, there are quantifiable economic benefits in the form of reduced expenses. Second, there are tangible benefits of a non-economic nature that customers are currently experiencing. Finally, the system PPL Electric has installed provides a platform from which PPL Electric can develop additional functionality that will provide both economic and non-economic benefits to customers in the future.

Q. Please describe the economic benefits of the AMR system.

A. The most fundamental benefit is that the manual reading of meters for billing is discontinued and the meter reading workforce can, over time, be eliminated. Expenses associated with salaries, benefits, and overheads (including vehicles) will be eliminated.

There will also be savings at PPL Electric's call center. With AMR, the need for and number of estimated reads will be reduced and customer calls regarding estimated meter readings and access to meters are virtually eliminated. In addition, the time required to handle telephone calls regarding high usage/high bills will be greatly reduced because the CSRs have available to them actual daily usage information for each account for the previous 45 days. The availability of daily usage information allows a CSR to more quickly resolve with a customer whether the usage billed is indeed accurate.

The ability to obtain meter reads remotely will also greatly reduce the need to send a serviceman to obtain special reads in circumstances such as a final read (when an account is closed) and for high usage/high bill investigations. The reduction in special reads translates, over time, into a reduction in the need for servicemen.

Savings are also expected to be realized at PPL Electric's meter shop as there will be less maintenance to perform given that the population of meters will, on average, be significantly newer than the population it replaced.

The automated data monitoring functions inherent in the new system will eliminate the need to perform manual monitoring of data quality from about 30,000 of PPL Electric's commercial and industrial customers who had metering that required transformation equipment to obtain readings instead of reading consumption directly at the supply voltage.

Finally, a few meters in the previous population were significantly under-recording usage. The mass replacement has resulted in the replacement of these meters when, under normal circumstances, their condition would have gone unnoticed. The metering and billing of this use represents revenue that the vast majority of customers (over 99% of them) no longer have to provide and, thus, represents an additional economic benefit from their perspective. In addition, this is likely a significant "fairness" issue in the eyes of these customers.

Q. How do these benefits compare to the costs of the AMR installation?

A. The $160 million in capital cost has, associated with it, a net present worth of carrying charges over its 15-year life of $198 million. It is estimated that the benefits described above provide a cumulative net present worth economic value of $205 million over the same period. The difference between the two indicates that revenue requirements will be lower with AMR than they would be without AMR over time.

Q. You mentioned a second category of benefits -- tangible benefits of a non-economic nature that customers are currently experiencing. Could you please describe these benefits?

A. Several of the items described above as producing an economic benefit also have a customer satisfaction component. For example, we know from surveys and past experience that a significant number of customers are unhappy with estimated reads. AMR will not only greatly reduce the expense PPL Electric incurs associated with estimated reads, but it will also eliminate the dissatisfaction that customers experience when they receive a bill based on an estimated read and the inconvenience of make-up bills (and potentially of payment arrangements) that may result from estimates that are too low.

Similarly, while we have identified an economic benefit associated with bringing better information to the discussion with customers of high usage/high bills, we have also experienced that the availability of 45 days of actual usage data helps to resolve those discussions in a way that is more satisfying to the customer. Finally, while we have identified an economic benefit associated with avoiding special reads, we have also relieved the customer of the burden of arranging those reads and, in some cases, access to the meter.

In addition, there are some significant benefits that have been brought to customers, but that we have not attempted to quantify. During Hurricane Isabel, the ability to communicate with meters was used to help manage restoration efforts. Once repairs were done in certain areas, meters were queried in order to determine whether that specific repair had addressed all of the problems in the area or whether there was another line or device in need of repair. This helped make restoration efforts more efficient and helped to provide customers more accurate estimates of when their service would be restored. PPL Electric expects to more fully develop this capability once AMR deployment is complete. Also, when a customer calls to report an outage, the meter can be queried to determine whether the problem exists on PPL Electric's side of the meter or on the customer's side. In the event that it is on the customer's side, he would no longer have to wait for PPL Electric to dispatch field personnel to make that assessment.

Q Finally, you identified a third category of benefits related to the development of additional functionality within the AMR system. Could you please describe the nature of such benefits?

A. Yes. Following are four examples of benefits that will likely be available in the future as AMR functionality is expanded:

1. AMR capabilities support the development of new rate options that will permit customers to achieve significant savings. As an example, participants in PPL Electric's Demand-Side Response Pilot – Residential (described in more detail later) have demonstrated the ability to save significant amounts on the generation portion of their bill. A full scale program will be possible with the development of a system to manage the collection of hourly meter data and the manipulation of that data into billing quantities.
2. At the end of the generation rate cap, data obtained through an enhanced AMR system will support generation purchases and pricing for Provider of Last Resort ("POLR") loads. This more detailed data may enhance load scheduling and reconciliation leading to a reduction in wholesale procurement risk and, perhaps, a commensurate reduction in wholesale price. The availability of AMR data to customers can help them to make decisions regarding the pricing options that are likely to be available in that time frame.
3. Data from an enhanced AMR system may support more optimal utilization of the distribution system. More detailed data may help to delay upgrades (and their rate impacts) or identify more efficient upgrades (and minimize their rate impacts).

4. The analysis of data obtained through an enhanced AMR system may be useful in identifying theft of service.

Q. When does PPL Electric expect to pursue these enhancements of the AMR system?

A. PPL Electric's initial objective was to install a system that would provide its customers near-term benefits and, also, be flexible enough to provide additional benefits as restructuring of the industry continues to evolve. PPL Electric's AMR project is one of the largest and most aggressive AMR projects ever undertaken. PPL Electric decided to focus at the outset on implementing the basic capabilities and assure that those capabilities were working and providing benefits to customers before pursuing enhancements. Furthermore, some of the future benefits will not be available to customers until the generation rate cap expires on December 31, 2009. PPL Electric believes that it is appropriate to defer such expenditures until closer to the date when the customer is likely to experience the benefit. As a first step, PPL Electric is currently investigating data management and storage issues that must be addressed as part of any of the above enhancements.

<u>Recovery of AMR Displacement Costs</u>

Q. Please explain PPL Electric's request for the recovery of costs associated with employees displaced by the AMR installation.

A. As described earlier, a significant portion of the benefits achieved by the AMR project is the elimination of manual processes associated with the prior metering system. With the elimination of manual processes comes the opportunity to reduce the workforce. PPL Electric estimates that the deployment of AMR will ultimately lead to a substantial reduction in the number of positions from what would have otherwise existed without AMR. The displacement of employees carries with it certain costs. PPL Electric has been able to accommodate most of these displacements through normal attrition within PPL Electric; i.e., employees displaced by AMR have been trained to fill vacancies that arose as a result of the normal course of retirements and severance. However, with a displacement this large, the normal rate of attrition has not been enough. Accordingly, the Company offered enhanced severance benefits to 94 employees in order to capture the payroll and benefits savings of AMR. In September 2003, PPL Electric recorded an $8.8 million charge to reflect the estimated costs of enhanced benefits for 94 employees to be separated as part of the AMR project. These costs are based on an actuarial study. The employees will be separated throughout 2003 and 2004 as the AMR deployment gradually eliminates the need for manual meter reading and the processes that support manual readings. As part of this filing, the Company is requesting the amortization of this $8.8 million charge over a period of five years. This request is included as an adjustment to Operating and Maintenance Expenses in the future test year and, accordingly, is included in Schedule D-2 of Exhibit Future-1.

Q. Please describe PPL Electric's rationale for requesting recovery of these costs.

A. The savings to customers of eliminating manual meter reading over the life of the AMR investment were described earlier. As noted earlier, the AMR project produces a net cumulative present worth reduction in revenue requirements over the life of the investment. Capturing those benefits also requires the up-front one-time expense of $8.8 million for employee displacement costs. PPL Electric believes that this expense is fundamentally similar to the capital investment and that it is appropriate to seek recovery of this expense from customers because it is the customers who ultimately receive the benefits of AMR.

Q. Why does PPL Electric request a five-year amortization of costs incurred as a result of the displacement of employees?

A. PPL Electric believes that a five-year amortization reflects an appropriate dilution of this event through customer bills and is consistent with prior Commission practice regarding the amortization of such one-time costs. Also, consistent with prior Commission practice, PPL Electric is requesting a simple five-year recovery of the $8.8 million and is not requesting a return on amounts not yet recovered.

<u>Demand Side Response Programs</u>

Q. Please describe PPL Electric's approach to demand side response.

A. PPL Electric has been and continues to be a strong supporter of market approaches to electricity supply issues. The Company was an early supporter of the deregulation of generation markets and, consistent with that position, PPL Electric believes that a demand side response to market price signals is an important element of a viable competitive generation market. PPL Electric further believes that this can be accomplished within existing jurisdictional structures by having the entities that serve retail load, both Electric Generation Suppliers

(EGSs) and default suppliers, offer demand response programs to their end-use customers. The reduction in demand that results from individual customers' response to price will be seen in the wholesale market as a change in the load servers' aggregate demand. PPL Electric believes that such programs are a natural extension of EGS's participation in the market and their need to manage risks. Default suppliers, on the other hand, participate in generation markets by obligation rather than choice and must be fully compensated for risks associated with that obligation. Their interest in demand side response is further complicated by generation rate caps, supply arrangements that may have been made as a result of restructuring, and distribution rate caps that inhibit their ability to recover the cost of any infrastructure required to support demand response programs. PPL Electric also believes that demand response programs can facilitate efforts to promote energy efficiency and environmentally responsible energy use (assuming that environmental factors are reflected in prices).

Q. Does PPL Electric, as a default supplier, offer its customers any demand side response programs?

A. Yes. In fact, many of the Company's programs pre-date restructuring. The Company's interruptible programs for industrial customers were first initiated in the 1980's, and incorporated components related to both reliability (in the form of emergency interruptions) and price response (in the form of economic interruptions). In the middle-1990's, the Company introduced an experimental price response service that permits industrial customers to purchase generation to serve incremental load above a baseline at a price that varies hourly and is forecast a day ahead using information from PJM's day ahead energy market. This rate also permits customers to be compensated by PPL Electric at the same prices for reductions below their baseline usage. Both of these programs were closed to new customers as part of the settlement of PPL Electric's restructuring case, but a total of about 70 customers continue to take service under these programs.

Q. Has PPL Electric offered demand side programs more recently to its industrial customers?

A. Yes. In 2001, PPL Electric obtained Commission approval to offer an experimental Demand Side Initiative Rider to eligible large commercial and industrial customers that allowed those customers to designate portions of their load to market pricing. Although a few customers have inquired about the rate, none have chosen to elect this option. It is possible that commercial and industrial customers who may be interested in demand side response programs have, instead, found the programs offered by PJM to be more advantageous. Indeed, about 25 of PPL Electric's customers participated in PJM load response programs during 2003. Nevertheless, PPL Electric is proposing in this filing to extend the availability of this rider beyond its currently scheduled expiration date of January 1, 2005 to January 1, 2008.

Q. Has PPL Electric offered demand response programs to its residential customers?

A. As with its commercial and industrial customers, PPL Electric has a long history of offering demand side programs to its residential customers. These include off-peak water heating and residential thermal storage programs that involve equipment on the customers' premises and rates that encourage customers to shift loads from on-peak periods to off-peak periods. These programs were closed to new customers as part of the settlement of PPL Electric's restructuring case, but a total of about 15,000 residential customers continue to take service under these programs.

Q. Has PPL Electric offered demand side programs more recently to its residential customers?

A. Yes. In 2002, PPL Electric obtained Commission approval to offer an experimental Demand Side Response Rider – Residential over a three-year period to up to 200 eligible residential customers. This rider provides those customers a rate incentive to shift their load from on-peak periods to off-peak periods during the four summer months. To qualify for this program a customer must have an AMR meter. As a result, the only customers eligible in the first year were those included in the AMR project's test population. About 25 customers participated during July, August, and September of 2002. Approximately three-quarters of the monthly bills rendered to participants during this period were lower as compared to what they would have been charged for standard residential service under Rate Schedule RS. The summertime electric bills for participants were, on average, $3.31 per month below what they would otherwise have been. For those customers whose bills were lower, the average saving was $6.10 per month for the summer period. In aggregate, the participating customers saved about $202 on the generation component of their electric bills. PPL Electric estimates based on actual Locational Marginal Prices that, over the same period, the shifting of load translated into a saving of about $230 to serve those customers compared to the cost to serve a normal residential load profile. While this was a modest beginning, the fact that customers captured benefits from their actions that were nearly equivalent to the value of those benefits in the energy market suggested that this approach had merit. Follow-up customer research determined that participants were generally pleased with the program. PPL Electric spent about $65,000 on solicitation and enrollment, programming of necessary billing system changes, customer research, and administration and monitoring.

Q. What was PPL Electric's experience with this program in 2003?

A. In 2003, PPL Electric was able to expand the customer base because the AMR project had reached more customers. In 2003, following an extremely positive response to early solicitations, PPL Electric obtained Commission approval to increase the participation limit to 300 eligible customers. About 275 customers participated in 2003 and, again, about three-quarters of the monthly bills rendered to participants during this period were lower as compared to what they would have been charged for standard residential service under Rate Schedule RS. The summertime electric bills for participants were, on average, $2.82 per month below what they would otherwise have been. For those customers whose bills were lower, the average saving was $4.93 per month for the summer period. In aggregate, the participating customers saved about $3,037 on the generation component of their electric bills. PPL Electric estimates based on actual

Locational Marginal Prices that, over the same period, the shifting of load translated into a saving of about $2,204 to serve those customers compared to the cost to serve a normal residential load profile. Clearly, the balance between customer savings and avoided costs that existed in 2002 did not exist in 2003 as participants during 2003 achieved benefits from their actions that were significantly greater than the value of those actions in the energy market. PPL Electric's preliminary analysis indicates that actual off-peak prices were higher in 2003 than in 2002 so that there was less real value associated with the shifting of kWhs in 2003 than in 2002, even though the customer billing values remained about the same (i.e., about 8 cents/kWh on-peak and about 3 cents/kWh off-peak). Again, follow-up customer research found that participants were generally pleased with the program. In 2003, PPL Electric spent an additional $73,000 on solicitation and enrollment, communication with prior year participants, customer research, and administration and monitoring.

Q. What are PPL Electric's plans for the program in 2004?

A. The Commission approved PPL Electric's initial proposal for the program to last for three summers; i.e., through September 30, 2004. PPL Electric plans to offer all existing participants the opportunity to participate for another summer. While the tariff offers PPL Electric the opportunity annually to review and request revision of on-peak and off-peak hours and rates, PPL Electric will forego that review and use the on-peak and off-peak rates currently shown in the tariff. While PPL Electric believes that different rates may be appropriate, we are concerned that a narrowing of the benefit and the corresponding decreased potential for savings may result in a decline in participation. PPL Electric believes that this is a valuable experiment and wants to have enough participants that results are meaningful. During 2004, PPL Electric will continue to analyze the results, and as an active participant in the Commission's Demand Side Working Group, expects to share data and analysis with that group to assist in the development of policy regarding demand side response programs.

Q. Does PPL Electric propose to continue this program beyond 2004?

A. Yes. PPL Electric is proposing in this filing to extend the availability of this rider beyond its currently scheduled expiration date of September 30, 2004 to September 30, 2007. PPL Electric continues to believe that this program has merit. While the results of 2003 suggest that it may not be an appropriate offering during the period that generation rate caps are in place, the willingness of customers to shift load and their overall positive reaction to the program indicate that it may be an important offering in the post generation rate cap period where pricing can reflect the cost of wholesale procurement. Accordingly, PPL Electric plans to use this additional time to further understand customer behavior, develop and test alternative program designs, and, also, further develop the AMR infrastructure to support programs such as this on a larger scale when the generation rate cap ends. In the absence of meter data management systems and billing interfaces that would allow hourly data to be used directly for billing, PPL Electric is proposing to continue to limit the program to not more than 300 participants.

Principles and Objectives Applied to Rate Design

Q. Please describe the principles that guided PPL Electric in the allocation of revenue requirements to customers.

A. The fundamental principle that PPL Electric employed to guide the allocation of revenue requirements to customers was that the allocation of revenue requirements among classes of customers should reflect the cost of providing service to those classes. The impact of that principle is apparent in several aspects of this filing:

- Because this is a distribution system rate increase the allocation of distribution-related revenue requirements falls more heavily on customers who take service at lower voltages (i.e., make greater use of the distribution system) than on customers who take service at higher voltages (i.e., rely less on distribution equipment). This result is evidenced by the fact that more than 90% of the distribution revenue requirement falls to residential and commercial customers.
- Because distribution charges are a larger portion of the total bill of residential and commercial customers, the effect of the request is a greater percentage increase, on a total bill basis, for residential and commercial customers than for industrial customers.

Q. Do the resultant allocations conform exactly to this principle?

A. No, they do not. If prior allocations had conformed to the principle, then the answer could be "yes"; however, those prior allocations date back to 1995 when rates were fully bundled and included significant cross-subsidies among customer classes. Those cross-subsidies were further compounded by the unbundling of bills that took place with deregulation that had the effect of driving the cross-subsidies into the unbundled components. While it is PPL Electric's goal to eliminate these cross-subsidies, we recognize that this cannot be achieved all at once without significant disruption. In particular, because residential customer rates were subsidized in the past by others and because distribution is such a significant portion of their bill, residential customers would see a sudden and significant increase in rates if cost of service principles were strictly followed. While PPL Electric believes that customer rates should reflect the costs those customers place on the electric system, PPL Electric also believes that this can and should happen gradually over time. Accordingly, the allocations proposed in this filing reflect a step in the process of establishing cost-based rates.

Specifically, PPL Electric established the following objectives in allocating revenue requirements:

1. Keep the increase on a total-bill basis to all residential rate schedules below 10%. "Total-bill" basis means that the allocation process included both the distribution increase proposed in this case and an estimate of the increase in transmission rates that will also occur on January 1, 2005.
2. Keep the increase on a total-bill basis to all rate schedules below 10%.
3. Move the relative rate of return for each customer class closer to the system average rate of return.

PPL Electric was able to achieve all of these objectives. The combination of the distribution increase proposed in this filing and the estimated increase in transmission rates that will be passed through on January 1, 2005 result in increases on a total-bill basis that are less than 10% for all rate schedules. In addition, consistent with the results of the class cost of service study, PPL Electric allocated the revenue requirements such that each rate schedule's relative rate of return moves toward the system average in terms of percentage contribution to the system average return.

Q. Please describe the principles that guided PPL Electric in the design of rates to recover those revenue requirements.

A. The fundamental principle employed to guide the design of rates was, consistent with the nature of distribution service, to move from revenue collection through usage based charges to revenue collection by fixed charges. There is very little distribution system cost that is a function of usage. From the perspective of correct economics, it is appropriate to collect fixed costs on a fixed basis. This becomes particularly important when a customer considers different options for the generation portion of his/her bill. A customer's buying decision with regard to generation is fundamentally a function of usage, and that decision can be distorted when non-usage related components are also being collected on a usage basis. Moving the collection of distribution costs from a usage basis to a fixed basis will make the savings available from Electric Generation Supplier options more clear to customers and promote competition. But even beyond the selection of an alternate supplier, one of the broad goals of restructuring has always been to make customers aware, through rates, of the consequences of their generation buying preferences. These include not just price, but, also, the amount of consumption, the use of different energy sources, and the burden those choices place on the environment. Moving the collection of distribution costs from a usage basis to a fixed basis will help to clarify these issues for customers as well. This issue becomes even more important as we approach the end of the generation rate cap.

Q. How has PPL Electric addressed this issue in this filing?

A. PPL Electric has, where appropriate, designed distribution rates that increase the proportion of revenues that are collected through either customer charges or demand charges, and has reduced the proportion that are collected through kWh charges. Mindful that such a redesign can introduce significant changes among usage levels within rate schedules, PPL Electric proposes, consistent with the principle of gradualism, modest changes in this regard. For example, while PPL Electric is proposing an increase in the customer charge in residential Rate Schedule RS from \$6.47 per month to \$12.20 per month, PPL Electric is also proposing to no longer place a distribution charge on the first 200 kWh of usage. In this way, the proposed rate design is able to satisfy the objective of moving toward fixed collections while keeping the increase for about 90% of residential bills to less than 10% (on a total-bill basis). It is acknowledged that the remaining 10% of Rate Schedule RS bills will see increases of greater than 10% and that, in the extreme, a customer who uses no electricity would see a monthly increase of about 88%. However, it is also true that the cost of providing distribution service is not a function of usage and that the customer who uses no electricity in a particular month (as, for example, in the case of a vacation home) is simply moving toward a charge that more correctly reflects the cost of being connected to the system.

Q. How will this proposed rate design affect low-income customers?

A. PPL Electric does not have income data on all of its customers, but it does have income information regarding customers who are receiving payment assistance. *During 2003, about 1.2 million bills (roughly 9% of the total number of bills) were rendered to customers who were receiving payment assistance and were coded* at Income Levels 1 or 2 as defined by the Bureau of Consumer Services. Analysis of these two groups of bills shows that the low-income customers tend to use more electricity than the other customers:

- About 95% of the low-income bills were for more than 200 kWh per month whereas only 89% of the other bills were for more than 200 kWh per month.
- The median usage among low-income bills was about 900 kWh per month whereas the median usage among other bills was only about 700 kWh per month.

This analysis shows that the proposed rate design for Rate Schedule RS actually helps to protect low-income payment assistance customers and may well protect low-income customers in general.

Pass-Through of FERC-Approved Transmission Charges

Q. PPL Electric's Statement of Reasons for the Proposed Increase explains that, apart from the distribution rate increase requested in this proceeding, transmission service charges reflected in the retail rates of customers taking Provider of Last Resort service from the Company are expected to increase by approximately $57 million effective January 1, 2005. Please describe these transmission service charges.

A. Entities that serve load, both Electric Distribution Companies serving customers taking Provider of Last Resort ("POLR") service and Electric Generation Suppliers, must obtain transmission service in order to deliver generation from the generating plants to the distribution systems to which their generation customers are connected. Load serving entities obtain transmission service from the Pennsylvania-New Jersey-Maryland Interconnection, LLC ("PJM") and are charged by PJM for that service under PJM's Open Access Transmission Tariff ("OATT") which is subject to review and approval by the FERC. PPL Electric is a load serving entity providing generation service to POLR customers, i.e., those customers who do not obtain generation service from an Electric Generation Supplier or whose chosen Electric Generation Supplier fails to provide contracted for generation service. In order to serve its POLR customers, PPL Electric must obtain transmission service from PJM and is billed by PJM in accordance with the OATT. In accordance with the tariff approved as part of the restructuring case, PPL Electric is entitled to automatically pass costs for transmission service consistent with the OATT accepted or approved by the FERC through to POLR customers.

Q. Has PPL Electric been able to fully recover from its POLR customers the cost of transmission service to serve those customers?

A. No, it has not. PPL Electric has been under a voluntary cap on the sum of its transmission and distribution charges which it agreed to as part of the settlement of its restructuring case filed pursuant to the Electric Competition Act. Both distribution costs and transmission costs have increased since that settlement. With the expiration of the cap on January 1, 2005, PPL Electric is seeking to correct both situations, i.e., obtain Commission approval to increase its rates for distribution service and pass through to POLR customers the full cost of transmission service.

Q. How are transmission charges reflected in this filing?

A. PPL Electric's primary reason for identifying this future increase in transmission charges at this time is to assure that its request for an increase in distribution rates is viewed in the proper context. In order to accomplish its allocation and rate design objectives, and to provide the Commission and PPL Electric's customers with a complete understanding of rate impacts expected to occur on January 1, 2005, PPL Electric has reflected the likely impact of higher transmission charges. Consequently, all of PPL Electric's allocation and rate design testimony and exhibits in this filing assume that transmission payments to PJM incurred in the supply of generation service to POLR customers will increase by an estimated $57 million over current levels as a result of the expiration of the rate cap. PPL Electric has further assumed that, consistent with the current collection mechanism, transmission costs will be collected from retail customers on a cent per kWh basis. However, whereas the current cent per kWh rates varies among rate schedules, the calculations performed in this filing reflect a uniform transmission charge expressed in cents per kWh that would be applied to all POLR customers on all rate schedules. While the actual amount of the charge will depend on the actual level of PJM charges at the time the cap expires, the estimated increase of $57 million increase will result in a charge rate for transmission service of 0.564 cents per kWh and that is the amount reflected in this filing. With these assumptions, PPL Electric has been able to design rates that will permit the collection of both its distribution revenue requirement and its expected Increase in transmission service charges and result in an increase of about 8% on average and less than 10% for most residential customers.

Q. Does the flat charge for transmission reflect a change in the allocation of transmission costs?

A. The change to a flat charge does result in an allocation of transmission costs among customers that is different than the current allocation. However, one needs to keep in mind that the current allocation actually dates back to the bundled rates that reflected a fully integrated utility that provided its own transmission service as part of fully bundled service. Transmission service itself has been restructured and the transmission service that PJM provides in the restructured environment is very different from the transmission service that PPL Electric charged for in the former regulated environment. PPL Electric believes that a uniform rate across all customers and all kWh is a more appropriate structure because (1) it is generally consistent with how PJM bills all load servers – Electric Distribution Companies and Electric Generation Suppliers – and (2) it permits the calculation of a simple cent per kWh "price to compare" that can be used by customers who may be shopping for supply to evaluate offers from Electric Generation Suppliers. PPL Electric is requesting, as part of this filing, the Commission's approval to charge all of its POLR customers a uniform cent per kWh rate for transmission charges beginning January 1, 2005.

Q. How does PPL Electric propose to pass changes in transmission service costs on to its POLR customers in the future?

A. PPL Electric recognizes that, from time to time, changes may occur to the PJM OATT that will change PPL Electric's payments to PJM and, as a consequence, the amount that PPL Electric must collect from its POLR customers. Under the restructuring settlement and Commission-approved tariff, such changes would be reflected in customer bills on an as needed basis. This could create customer confusion and, also, make shopping decisions more difficult for customers as transmission cost is a component of the Price to Compare. Questions regarding over and under collection might also arise. To address these issues, PPL Electric is proposing in this filing a transmission rate tracking mechanism that would function in a manner similar to the former Energy Cost Rate. PPL Electric's proposed tracker would be reset annually to (1) reflect the current level of transmission charges and forecast of POLR sales and (2) a reconciliation of prior year collections to costs. Mr. Kleha describes PPL Electric's proposal in more detail in his direct testimony (PPL Statement No. 5).

<u>Distribution System Improvement Charge</u>

Q. Please explain PPL Electric's request to institute a Distribution System Improvement Charge ("DSIC").

A. The DSIC that PPL Electric proposes is a rate mechanism that would allow PPL Electric to recover, between formal rate cases, the carrying costs on certain capital investments in distribution facilities. In the absence of DSIC, PPL Electric can collect no money from customers to support these investments in facilities until they are recognized as additions to rate base in the context of a formal rate proceeding. This situation can go on for years and is becoming increasingly critical as distribution facilities built in the high growth 1960s, 1970s, and 1980s are nearing the end of their useful lives. The DSIC will enable PPL Electric to begin collecting money to cover the carrying costs of these facilities shortly after the facilities are completed and providing service to customers. As a result, PPL Electric will be better able to finance the construction of facilities that are required to maintain safe and reliable service without the immediate need to file a formal base rate case.

Q. What investments in facilities does PPL Electric propose be subject to DSIC?

A. PPL Electric proposes three categories of investments that would be eligible for cost recovery under DSIC. These are:

- Replacements for existing facilities that have worn out, are in deteriorated condition, or need to be upgraded to meet new regulations.
- Unreimbursed costs related to capital projects that relocate Company facilities due to highway relocations.
- Security improvements that are recommended by a Federal or State governmental entity with appropriate jurisdiction over security matters.

Common themes among these categories are that (1) they are not intended to serve new customers so there will be no new revenues to support the investment and (2) from the perspective of PPL Electric these investments are not discretionary.

Q. Is there a precedent for DSIC?

A. Yes. A DSIC has been available to Pennsylvania water companies since the mid-1990s. The Commission's recommended tariff language for water company DSIC is as follows (Opinion and Order at Docket No. P-00961031, Petition of Pennsylvania-American Water Company for Approval to Implement Tariff Supplement Establishing a Distribution System Improvement Charge) :

> "Purpose: To recover the fixed costs (depreciation and pre-tax return) of certain non-revenue producing, non-expense reducing distribution system improvement projects completed and placed in service and to be recorded in the individual accounts, as noted below, between rate cases and to provide the Company with the resources to accelerate the replacement of aging water distribution infrastructure, to comply with evolving regulatory requirements imposed by the Safe Drinking Water Act and to develop and implement solutions to regional

> water supply problems. The costs of extending facilities to serve new customers are not recoverable through DSIC."

It is PPL Electric's proposal to establish a similar recovery mechanism for similar investments in electric distribution facilities.

Q. What is PPL Electric requesting the Commission to approve in this filing?

A. PPL Electric is requesting the Commission approve the DSIC as a mechanism to recover the carrying costs associated with future capital investments. The DSIC does not, however, affect PPL Electric's claim for rate base in the Future Test Year. PPL Electric's forecast of Future Test Year rate base already includes projects that, in the future, would be eligible for PPL Electric's proposed DSIC, thus the proposal does not either increase or decrease PPL Electric's revenue requirements or proposed rates in the instant filing. Mr. Kleha describes PPL Electric's proposed collection and reconciliation mechanism in more detail in his direct testimony (PPL Statement No. 5).

Q. When would customers be affected by PPL Electric's proposed DSIC?

A. PPL Electric proposes that DSIC be an annual charge, so it would be PPL Electric's intent to accumulate DISC-eligible investments from the effective date of this tariff until one year after the effective date of this tariff. As proposed, DSIC-eligible investments would be accumulated between January 1, 2005 and December 31, 2005. PPL Electric would then calculate the DSIC charge and the initial DSIC would first appear on bills rendered on January 1, 2006.

Q. What would the impact of PPL Electric's proposal be on customers?

A. PPL Electric has analyzed a typical year's worth of property additions and identified about $26 million of property additions that would be eligible under the proposed definition. We have further estimated that the DSIC formula would result in about $3.3 million in revenues that would have to be collected. The proposal would spread this across about 35 billion kWh; resulting in a charge of about 0.01 cents per kWh. For a small residential customer using about 500 kWh per month, the DSIC would result in an additional charge of about 5 cents. If there were no base rate proceeding, that property would be eligible again in the next year, as would additional eligible property installed during the second year. Assuming a similar amount of eligible property in the second year, the charge would increase to 10 cents per month in the second year.

Q. What safeguards are provided for customers in PPL Electric's proposal?

A. PPL Electric's proposed DSIC provides the following safeguards for customers:

- This rate case and the recognition of property additions in rate base provides customers assurance that only eligible property placed in service after the effective date of DSIC will be reflected in the DSIC calculation.
- As proposed, DSIC is subject to an annual review and reconciliation to provide customers the assurance that only eligible property is being included and that any overcollection will be refunded in the following year. The reconciliation benefits the Company by assuring that any undercollection will be recovered in the following year.
- The fact that, at future rate cases, DSIC-eligible property will be included in rates and the DSIC will be reset to zero provides customers the assurance

that the base rate process still functions to subject all additions to rate base to appropriate Commission review.

- The proposal that DISC charges be limited to not more than 5% of distribution charges provides customers the assurance that DSIC is only an interim mechanism and does not replace base rate proceedings as the ultimate mechanism by which property additions are reflected in rates.

Amortization of Costs Associated with Hurricane Isabel

Q. Please explain PPL Electric's request for the amortization of costs associated with Hurricane Isabel.

A. On October 20, 2003, PPL Electric requested Commission authority to defer, for accounting and financial reporting purposes, losses arising from severe damage caused by Hurricane Isabel and to amortize those loses for recovery from customers in a future base rate proceeding. Hurricane Isabel struck PPL Electric's service territory most heavily during the evening of September 19, 2003 and the morning of September 20, 2003. The losses which PPL Electric sought to defer were increases in operation and maintenance, customer, and general administrative expenses incurred by PPL Electric in preparing to respond to the damage from Hurricane Isabel, restoring service to customers, assisting customers during the service interruptions, and repairing facilities damaged by the storm. In its petition, PPL Electric specifically acknowledged that it was not requesting that the Commission decide, at that time, whether its deferred losses were recoverable from customers. PPL Electric stated in its petition that approval to recover such losses as well as the length of the amortization would be determined in such future rate base proceeding. The Commission granted PPL Electric's request to defer storm-related losses for accounting and financial reporting purposes in an order entered on January 16, 2004 at Docket No. P-0032069. In the instant proceeding, PPL Electric is requesting the amortization of $15 million in costs related to Hurricane Isabel over a period of five years. This request is included as an adjustment to Operating and Maintenance Expenses in the future test year and, accordingly, is included in Schedule D-2 of Exhibit Future-1.

Q. Please describe the damage that PPL Electric and its customers experienced as a result of Hurricane Isabel.

A. Hurricane Isabel was unquestionably an extraordinary event. Hurricane Isabel struck PPL Electric's service territory most heavily during the evening of September 19, 2003 and the morning of September 20, 2003. As the storm left PPL Electric's service territory, 502,516 of PPL Electric's customers through-out its 29 county service territory, about 38% of its entire customer base, were without service. The damage caused by Hurricane Isabel was so severe that PPL Electric was required to undertake the largest restoration effort in its history to restore electric service to all customers. The principal cause of damage was fallen trees and tree branches that brought down many sections of overhead distribution lines. High winds localized wind gusts reported at over 60 miles per hour caused the overwhelming majority of the damage. Adding to the strain that was placed on trees by the sustained winds was saturated ground from heavy rain in the weeks preceding Hurricane Isabel. Here are some facts that help place the severity of this event in context:

- PPL Electric generally considers a storm to be large if it causes more than 1,000 individual cases of system repairs. Hurricane Isabel caused approximately 3,943 individual cases of necessary system repairs.
- In making repairs, 174,000 feet of wire and 244 poles were replaced. The amount of material used in five days was equivalent to what PPL Electric normally uses in an entire year.
- About 161,000 customer phone calls were answered in three days. Normally, PPL Electric answers about 30,000 customer phone calls in a week. In addition to these incoming calls, PPL Electric made more than 42,000 outreach calls to inform customers of the status of repairs and of the availability of assistance programs. Through these programs, 3,000 gallons of drinking water, nearly 5,000 pounds of dry ice, and 4,000 bags of ice were distributed to customers at no cost to them.
- About 2,750 people were involved in the restoration including about 1,800 PPL employees from PPL Electric and other PPL affiliates; and about 900 people from other utilities and contractors from Canada, New England, New York, and the Midwest (Illinois and Iowa). Electric utilities that provided line crews included Massachusetts Electric (North Borough, Massachusetts), Narragansett Electric (Providence, Rhode Island), Granite State Electric (Lebanon, New Hampshire), Central Hudson Gas & Electric (Poughkeepsie, New York), KeySpan Energy (Brooklyn, New York), United Illuminating (New

Haven, Connecticut), NSTAR (Boston, Massachusetts), and Hydro Quebec (Montreal, Canada). Electrical and tree service contractors assisting in service restoration efforts included Asplundh, Dincher, Eastern Tree, Everhart and Hoover, Henkels & McCoy, Jaflo, JCR Construction (National Grid), K.T. Power, Kocher's Tree Service, L. E. Myers (Illinois and Iowa), T.C. Loyd, T. Ross Electric, Tall Trees Ontario, Three Phase Line Construction, and Williamsport Electric.

Q. Please describe the costs that PPL Electric incurred in restoring service to its customers and that it is requesting in this proceeding be recovered from customers.

A. PPL Electric incurred a total of $17.2 million in costs associated with Hurricane Isabel. Of that total, $15 million is for expense-related items and it is that amount that PPL Electric seeks to recover in this proceeding. The remaining $2.2 million is related to capital. PPL Electric did not request deferred accounting for capital expenditures arising from Hurricane Isabel and is not seeking to amortize recovery of capital items. These items are reflected in PPL Electric's rate base as property additions that occurred in 2003. The $15 million in expense-related items includes expenditures for the following:

- Wages including overtime
- Expenses for outside crews
- Expenses for vehicles and equipment
- Expenses for customer outreach
- Equipment charges.

Q. Does PPL Electric anticipate storms in the context of its budgeting?

A. Yes, PPL Electric does allocate a modest amount in its budget in anticipation that storms will occur. However, that amount is relatively small compared to the actual costs of a storm like Hurricane Isabel. In its 2003 budget, PPL Electric budgeted about $5 million for storm-related costs for the entire year based on the expectation of "normal" storm activity. Normal activity is 5 PUC-reportable storms with a restoration requirement of about 6,000 manhours each and one major storm requiring 20,000 manhours. Even with the expenses associated Hurricane Isabel excluded, storm restoration and repair work in 2003 totaled $11 million – well in excess of the $5 million that had been budgeted. Using a similar definition of "normal" storm activity, but adding funding to recognize that foreign utility crews needed for major storms are in addition to the 20,000 manhours, PPL Electric has included $7 million for storm-related costs in the 2004 budget that is reflected in the future test year. Clearly, the costs associated with storms of the magnitude of Hurricane Isabel are not reflected in the budgets of PPL Electric, nor are they reflected in the rates that the Company charges its customers, even though incurring those costs is wholly consistent with PPL Electric's obligation to provide reliable electric service to its customers.

Q. Why doesn't PPL Electric budget more money for storm-related costs and seek the recovery of such costs in rates?

A. PPL Electric recognizes the difficulty in forecasting storm events and the dichotomy that creates from a rate-making perspective. On one hand, PPL Electric and its customers would probably be in agreement that the Company should have the resources at its disposal to undertake a speedy restoration of service should a storm occur. However, on the other hand, both would probably also agree that the inclusion in rates of what amount to speculative costs for storms that might occur is a non-traditional approach to ratemaking. Absent a severe storm, customers would rightfully question how that portion of their rates was being spent. As distribution companies and the Commission work together to complete restructuring of the electric industry in Pennsylvania and to understand the financial impact of such events on distribution companies, it may be determined that a "storm recovery surcharge" may be appropriate. Such a mechanism would provide distribution companies the assurance that prudently incurred storm-related costs would be recoverable and it would provide customers the assurance that rates would reflect only prudently incurred costs and that, once recovered, those costs would no longer be reflected in rates. Absent such a mechanism, PPL Electric believes that a reasonable alternative is for distribution companies to continue to budget and reflect in rates amounts that are consistent with normal storm expenditures; i.e., the amount that is most likely to be spent in any year, and for the Commission to consider, on an as needed and requested basis, the recovery of prudently incurred costs associated with extraordinary storm events.

Q. Why does PPL Electric request a five-year amortization of costs incurred as a result of Hurricane Isabel?

A. Even though all of the costs were incurred during only a few days in 2003, PPL Electric believes that a five-year amortization reflects an appropriate dilution of this one-time event through customer bills and is consistent with prior Commission practice regarding the amortization of such one-time costs. Also, consistent with prior Commission practice, PPL Electric is requesting a simple five-year recovery of the $15 million and is not requesting a return on amounts not yet recovered.

Q. Does this conclude your direct testimony?

A. Yes, it does.

PPL ELECTRIC UTILITIES CORPORATION

Exhibit DAK 1
2004-2008 Capital Budget
Electric Utilities and Facilities Management

Witness: Douglas A. Krall
Docket No. R-00049255

Exhibit DAK1

2004-2008 Capital Budget
Electric Utilities and Facilities Management

	Thousands of Dollars					
Electric Utilities	**2004**	**2005**	**2006**	**2007**	**2008**	**Total for 2004-08**
Provide Electric Service	$70,443	$79,787	$83,011	$86,492	$90,967	$410,700
Upgrade System Facilities	42,540	51,035	68,400	79,258	65,413	306,646
Assure System Reliability	25,433	30,594	31,683	33,633	35,617	156,960
Revenue Cycle Service	3,640	5,946	6,056	6,196	6,308	28,146
Automated Meter Reading	16,508	------	------	------	------	16,508
Other	(229)	5,256	3,232	1,000	500	9,759
Respond to Customer	1,633	1,703	1,784	1,877	1,955	8,952
Total Electric Utilities	**$159,968**	**$174,321**	**$194,166**	**$208,456**	**$200,760**	**$937,671**
Facilities Management						
Replacement	$2,700	$5,891	$5,015	4,425	$6,060	$24,091
Working Conditions/Safety	4,541	4,259	5,135	5,875	4,240	24,050
Environmental	250	250	250	100	100	950
Total Facilities Management	**$7,491**	**$10,400**	**$10,400**	**$10,400**	**$10,400**	**$49,091**
TOTAL	**$167,459**	**$184,721**	**$204,566**	**$218,856**	**$211,160**	**$986,762**

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

PPL Electric Utilities Corporation

Statement No. 5

Direct Testimony of Joseph M. Kleha

Direct Testimony of Joseph M. Kleha

Q. Please state your full name and business address.

A. Joseph M. Kleha, Two North Ninth Street, Allentown, Pennsylvania, 18101.

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

A. I am employed by PPL Services Corporation ("PPL Services"), a subsidiary of PPL Corporation, in the Office of General Counsel as Manager - Regulatory Projects.

Q. What are your duties as Manager - Regulatory Projects?

A. I am responsible for overseeing corporate projects involving regulatory agencies on behalf of PPL Corporation's subsidiaries, including PPL Electric Utilities Corporation ("PPL Electric"); PPL Gas Utilities Corporation's two (2) gas utilities, PFG Gas, Inc. and North Penn Gas Company; PPL EnergyPlus, LLC ("PPL EnergyPlus"); and the PPL Generation family of companies. As part of this function, I review and provide technical oversight and guidance on the development, content and structure of cost allocation and revenue requirements studies. I also prepare and present expert testimony regarding these studies.

Q. What is your educational background?

A. I graduated from the Pennsylvania State University in 1974 with a Bachelor of Science Degree in Accounting. Since that time, I have taken specialized courses dealing with public utility accounting, depreciation and rate design. In addition, I attended the NARUC Regulatory Studies Program.

Q. Please describe your professional experience.

A. I was employed by the Pennsylvania Department of Public Welfare as Field Auditor and Institutional Collections Officer from 1974 to 1977. In 1977, I joined the technical staff of the Pennsylvania Public Utility Commission ("PUC") as a Utility Rate Analyst in its Bureau of Rates and Research. In this position, my responsibilities included review of proposed retail electric rate filings and the preparation and presentation of testimony in formal rate proceedings. This testimony primarily dealt with the allowable levels and jurisdictional allocations of claimed operating revenues, operating expenses, and rate base. In 1981, I joined PPL Electric as a Senior Accountant with responsibility for assembling financial data and preparing revenue requirement studies to support its retail and wholesale rate filings. I was named Manager - Regulatory Projects in PPL Electric's Office of General Counsel in 1990. In 2000, as part of a corporate realignment, I became an employee of PPL Services along with the other employees in the Office of General Counsel.

Q. Have you previously testified as a witness on cost-of-service and ratemaking related issues?

A. Yes. As an analyst in the PUC's former Bureau of Rates and Research, I offered testimony in the following electric utility rate proceedings:

Company	Docket No.
Duquesne Light Company	R-79010740
UGI Corp. - Luzerne Division	R-79050863
Philadelphia Electric Company	R-79060865
West Penn Power Company	R-80021082
Pennsylvania Power & Light Co.	R-80031114
Metropolitan Edison Company	R-80051196
Pennsylvania Electric Company	R-80051197

As an employee of PPL Electric and PPL Services, I have offered testimony in the following electric and gas utility proceedings before the PUC and the Federal Energy Regulatory Commission ("FERC"):

PUC	FERC
Docket No. I-900005	Docket No. ER88-545-000
Docket No. P-910521	Docket No. ER91-322-000
Docket No. M-00930406	Docket No. ER95-1267-000
Docket No. C-00935175	Docket No. ER96-930-000
Docket No. C-00935403	Docket No. ER96-931-000
Docket No. R-00943271	Docket No. ER96-932-000
Docket No. C-00957559	Docket No. ER96-933-000
Docket No. P-00961023	Docket No. ER96-1428-000
Docket No. C-00967591	Docket No. SC97-1-000
Docket No. C-00967955	Docket No. OA96-142-000
Docket No. C-00968035	Docket No. ER97-4829-000

Docket No. P-00961114
Docket No. R-00973954
Docket No. P-00001789
Docket No. M-FACE9908
Docket No. R-00005277
Docket No. M-FACE0008
Docket No. M-FACE0111
Docket No. R-00016850
Docket No. M-FACE0212

Docket No. ER97-3189-007
Docket No. EL98-25-000
Docket No. ER02-597-000
Docket No. ER03-421-002
Docket No. ER04-056-000

Q. Mr. Kleha, briefly describe the subject matter of your testimony in this proceeding.

A. My testimony and accompanying exhibits describe and support PPL Electric's calculation of certain ratemaking adjustments to the historic test year and future test year retail rate base, operating revenues and operating expenses; the development of the cost allocation studies which form the basis for proposed retail rates; the determination of jurisdictional investment and expense (capital and operating costs) and revenue requirements, and the unbundling of the retail cost of providing distribution service.

Q. Mr. Kleha, are you sponsoring any exhibits in this proceeding?

A. I am sponsoring Exhibits JMK1, JMK2 and JMK3. I also am sponsoring portions of Exhibit Regs., Part 1-General Information, Part II-Primary

Statements of Rate Base and Operating Income, Part IV-Rate Structure and Cost Allocation, and Part V-Plant and Depreciation Supporting Data, including Related Depreciation Study Report.

<u>Exhibits Historic 1 and Future 1</u>

Q. Are you sponsoring any schedules in Exhibits Historic 1 and Future 1?

A. Yes. I am sponsoring the following: Schedules C-4, C-6, D-12, D-13, D-14 and D-15 of Exhibits Historic 1 and Future 1.

Q. Schedules C-4 of Exhibits Historic 1 and Future 1 show details of PPL Electric's claim for cash working capital. Would you explain these schedules?

A. Schedules C-4 of Exhibits Historic 1 and Future 1 are computations of PPL Electric's average investment in cash working capital. There are five major components in this computation: cash working capital required for operation and maintenance expenses; funds invested in prepayments; an adjustment for accrued taxes; an adjustment for interest payments; and an adjustment for preferred dividend payments.

Q. Would you explain these five components?

A. Page 2 of Schedules C-4 shows the first component, which is cash working capital required for operation and maintenance expenses. PPL Electric bills all of its customers once every month, but the due date for payment varies between 15 and 30 days from the billing date. On this basis, there is a considerable span of days between the time electricity is furnished to a customer and the time the customer pays for such electricity. This span averages 35 days for customers with 15-day due dates, 54 days for customers with 20-day due dates, and 39 days for customers with 30-day due dates. The average lag in receipt of revenues from all these sources is 45.5 days on a dollar-weighted basis.

In most instances, PPL Electric must pay its bills for payroll, employee benefits, support group costs and other operating expenses prior to the time it is able to collect the amount due for the service giving rise to these expenses. PPL Electric has examined its records to determine, as to the major categories of expense, the average span of days between the time an expense is incurred and the time it must be paid. On page 2 of Schedule C-4 of Exhibit Historic 1, the average span of days for major categories of expense is shown. This lag ranges from 12 days to 41 days for various types of costs. The overall average for all expenses is 32.1 days. Thus, the average net lag between the payment of expenses and the receipt of the related revenue is 13.4 days (45.5 days less 32.1 days). To cover its expenses and continue to conduct its business during this time lag, PPL Electric must provide a cash investment.

The second major component of cash working capital is made up of funds which are invested in prepayments. This amount is shown on page 3 of Schedules C-4. In conducting its electric business, PPL Electric must pay certain costs prior to the time such items are properly charged to expense for accounting and ratemaking purposes. For example, the PUC's annual assessment must be prepaid, but is expensed monthly over the period to which it applies. Costs of this nature initially are charged to FERC Account 165, Prepayments, and subsequently are charged to expense from this account.

The claim for prepaid expenses is based on the 13-month average of the various items included in Account 165. This amount has been claimed as a component of cash working capital for both the historic test year and future test year.

The third major component of cash working capital is the adjustment for accrued taxes, which is shown in detail on page 4 of Schedules C-4. In the case of Federal income tax, estimated payments must be made on April, June, September and December 15 of the year to which the tax is applicable. Because revenues are collected from customers monthly, there are funds temporarily available for payment of other costs. PPL Electric's computations indicate that funds available from this source average 3.52% of the federal income tax due.

Presently, the Pennsylvania income tax and Pennsylvania Capital Stock Tax have the following pattern of required estimated payments:

- 25% on March 15
- 25% on June 15
- 25% on September 15
- 25% on December 15

PPL Electric's computations indicate that the funds available from these taxes average 1.44% of the tax due.

The Pennsylvania gross receipts tax must be paid on an estimated basis by March 15 of the year to which the tax is applicable. Because revenue is collected from customers monthly, funds must be provided by investors to pay these taxes prior to the collection revenues from customers. PPL Electric's computations indicate that the funds which must be provided for this purpose average 36.06% of the tax due. This adjustment is based on the total

Pennsylvania gross receipts tax which must be paid at the 59 mill rate actually in effect.

The Pennsylvania Public Utility Realty Tax must be paid on an estimated basis by May 1 of the year to which the tax is applicable. Because revenue is collected from customers monthly, funds must be provided by investors to pay these taxes prior to the collection from customers. PPL Electric's computations indicate that funds which must be provided for this purpose average 23.56% of the tax due.

The net effect of these various accrued tax adjustments is an increase in PPL Electric's cash working capital requirement as shown on page 4 of Schedules C-4.

The fourth and fifth components of cash working capital are offsetting adjustments for the funds applicable to debt interest payments and preferred stock dividend payments, which are shown on pages 5 and 6 of Schedules C-4. PPL Electric "theoretically" has unrestricted use of these funds from the time of the monthly collection from customers until the payment of interest and dividends on a semiannual or quarterly basis. PPL Electric does not agree with the appropriateness of such a reduction to Measures of Value. However, this adjustment has been made in order to facilitate the adjudication of this filing and in compliance with the Commission's current policy.

Q. What is shown on Schedules C-6 of Exhibits Historic 1 and Future 1?

A. Schedules C-6 of Exhibits Historic 1 and Future 1 reflect the balances in deferred taxes at the end of the respective test years, including the tax deferrals related to the Accelerated Cost Recovery System ("ACRS"). This legislation provides for mandatory normalization of tax benefits on post-1980 property. PPL Electric has claimed only federal income tax normalization in this filing.

Q. Why aren't Accumulated Deferred Investment Tax Credits (FERC Account 255) reflected in the computation of Measures of Value?

A. Under provisions of the Revenue Act of 1971, public utilities were afforded the option of treating the investment tax credit in rate proceedings by reducing taxes over the life of the property and not deducting the accumulated amount of the credit from the Measures of Value.

On March 8, 1972, PPL Electric made this election as provided for under the Internal Revenue Code, Section 46(e), Paragraph (2), and, in compliance therewith, has not reduced the Measures of Value for the purpose of these proceedings. Such credits are, however, being amortized as a credit to operating expense over the life of the related property.

Q. Please explain the "Adjustment to Taxes Other Than Income Taxes" shown on Schedules D-12 for both the historic and future test years.

A. In order to derive the current level of Pennsylvania Capital Stock Tax, the valuation method used by the Pennsylvania Department of Revenue was utilized. This results in an estimated valuation at December 31, 2003 and December 31, 2004. The 7.24 mill tax rate is applied to the valuation to derive the total capital stock tax liability at December 31, 2003. The 6.99 mill tax rate is applied to the valuation to derive the total capital stock tax liability at December 31, 2004. This portion of the computation is set forth on Schedules D-12, page 2. From this amount is deducted the capital stock tax expense per books for the 12 months ended December 31, 2003, and the expense per budget for the 12 months ending December 31, 2004. This adjustment reflects both the current taxable valuation and the applicable tax rates.

Q. Please explain the Pennsylvania Gross Receipts Tax shown on Schedules D-12.

A. The adjustment to Pennsylvania Gross Receipts Tax is shown on Schedules D-12, page 3. This adjustment reflects the gross receipts tax liability changes which will result from base rate revenues generated by the annualization of sales.

Q. Please explain the adjustment for Pennsylvania Public Utility Realty Tax.

A. The Pennsylvania Public Utility Realty Tax is developed based on plant in service at December 31, 2003 and projected to be in service at December 31, 2004. From this amount is deducted the tax expense per books for the 12 months ended December 31, 2003, and the tax expense per budget for the 12 months ending December 31, 2004.

Q. Please explain the adjustment of federal and state income taxes, shown on Schedules D-13 for both test years.

A. Schedules D-13 show, in column 1, the tax computation as recorded for the 12 months ended December 31, 2003, and as budgeted for the 12 months ending December 31, 2004. Column 2 shows adjustments required to exclude revenues, expenses and income tax adjustments associated with POLR service and the recovery of stranded costs through the CTC. Column 3 shows the derivation of the revenues, expenses and tax adjustments for PPL Electric's combined transmission and distribution ("T&D") operations only.

Column 4 shows the various adjustments for a proper computation of taxable income on a pro forma basis at present rates. Column 5 shows the pro forma income tax computation at present rates.

Taxable income and the tax computations are adjusted in Column 4 for the following reasons:

- To reflect the effect on taxable income of adjustments to revenue and expense set forth on Schedules D-2 and to reflect other changes in taxable income.
- To eliminate prior year tax adjustments and provisions for possible tax deficiencies recorded on the books for the 12 months ended December 31, 2003, or reflected in the budget for the 12 months ending December 31, 2004.

Q. Are there several tax adjustments upon which you wish to elaborate?

A. Yes. They are the following:

Tax Depreciation

In general, depreciation for tax purposes must be computed using the tax basis of the property (which generally is lower than book basis) and using various depreciation methods and rates which differ from those used in computing book depreciation.

In computing tax depreciation, this filing has paralleled the methods used in PPL Electric's federal and Pennsylvania income tax returns. That is, for property acquired prior to 1981, where permitted, PPL Electric has used the declining balance method of depreciation with the 20% shorter lives permitted by the Class Life Depreciation System (commonly referred to as "ADR"). The Revenue Act of 1971 introduced ADR which permitted shortening or lengthening depreciable lives as much as 20% for tax purposes. For post-1980 property, the tax depreciation is based on the Accelerated Cost Recovery System ("ACRS") as provided for in the Economic Recovery Tax Act of 1981.

Annualized Interest

This adjustment is the result of normalizing the interest deduction based on the test year measures of value as shown on Schedules D-13, page 3. Because ratepayers pay a return on only these measures of value, it is only the interest associated with these measures of value that applies to PPL Electric's T&D operations for ratemaking purposes.

Q. Please summarize the effects of these tax adjustments.

A. Recognition of all tax adjustments reflected on Schedules D-13 results in a net decrease in taxable income for the historic and future test years. Taxable income is the basis for computing both federal and Pennsylvania income taxes.

The actual Pennsylvania Corporate Net Income Tax rate is 9.99%. The federal income tax is computed at the current 35% tax rate. For federal income tax purposes, the amount of Pennsylvania income tax is an allowable deduction. Details of the computations of all taxes incurred as a result of the proposed revenue increase are shown on Schedules D-13, page 4.

Q. *Please explain Schedules D-14, "Adjustments to Deferred Income Taxes," for both test years.*

A. Normally, deferred taxes arise in connection with expenses which, for various reasons, are recorded on the books as an expense in a different year than the same item is allowed as an income tax deduction. This is referred to as a timing difference. Generally accepted accounting principles prescribed by the Financial Accounting Standards Board ("FASB") require that the tax savings related to an expense be recorded on the books at the same time as the expense is recorded. For example, if the expense is booked in a year after its deductibility for tax purposes, a deferred tax charge is recorded on the income statement and a liability for such tax is recorded on the balance sheet in the year the tax deduction occurs. The same basic principle applies to revenue items, as well as expense items.

Schedules D-14 show the normalization of the net deferrals recorded on the books for the 12 months ended December 31, 2003, and as budgeted for the 12 months ending December 31, 2004.

It should be noted that for the year ended December 31, 2003, the specific items covered by deferred taxes all arise in connection with timing differences, as discussed above. Several of the items are expected to result in a continuing charge or credit to expense, the same as recorded on the books or as budgeted, and these items do not require adjustment for purposes of this rate filing. The following are unadjusted in both the historic and future years:

- Accelerated amortization of pollution control facilities
- Portion of tax depreciation arising from shortening lives by 20% under the class life depreciation system
- Cost of removing retired depreciable property
- Repair allowance
- Tax liability for Contributions in Aid of Construction

The major adjustment relates to the ACRS system of tax depreciation as set forth on Schedules D-14, page 2.

Regarding Schedules D-14, PPL Electric uses ACRS in computing tax depreciation on post-1980 property additions. Schedules D-14 reflect an adjustment for the mandatory deferral of the federal tax effects of ACRS based on the tax plant balances at December 31, 2003 and December 31, 2004.

Q. *Was the Pennsylvania state income tax effect of ACRS normalized and claimed in these proceedings?*

A. No. In accordance with this Commission's policy, it was not.

Q. Please explain Schedules D-15?

A. Schedules D-15 adjust the amortization of the investment tax credit to reflect a full year's amortization based on the unamortized investment tax credit remaining at December 31, 2003 and December 31, 2004, respectively.

Exhibits JMK1, JMK2 and JMK3

Q. Please explain how PPL Electric's Pennsylvania jurisdictional costs are derived.

A. This filing is based on the investment and expense incurred to provide distribution service to PPL Electric's Pennsylvania jurisdictional customers. Accordingly, PPL Electric's historic test year per books and future test year per budget delivery service operating results are adjusted to eliminate all revenues and expenses associated with the generation function, namely Provider of Last Resort ("POLR") service and the recovery of stranded costs through the

Competitive Transition Charge ("CTC") which was approved by the Commission in PPL Electric's restructuring proceeding at Docket No. R-00973954, to derive the combined T&D operations. T&D investment and expense are then allocated between the Federal (transmission) and Pennsylvania (retail distribution) jurisdictions. Exhibits JMK1 and JMK2 provide specific details regarding the allocation of those costs and the determination of the Pennsylvania jurisdictional distribution service revenue requirements on a system and rate class basis.

Q. Would you briefly describe the contents of Exhibits JMK1 and JMK2?

A. Exhibits JMK1 and JMK2 respond to Question 1 of Exhibit Regs., Part IV, Section E, and present fully distributed Pennsylvania jurisdictional costs of providing retail distribution service to the various rate classes at both present and proposed rates. The studies contained in Exhibit JMK1 are based on costs and operating conditions for the historic test year ended December 31, 2003. The studies contained in Exhibit JMK2 are based on costs and operating conditions for the future test year ending December 31, 2004. The objective has been to make each exhibit self-contained. Each exhibit provides a summary of the results, a computer printout of the cost allocation, and supporting schedules showing functionalization of the costs and support for the cost allocation factors used. Explanatory material with regard to methods employed and cross-referencing to Exhibits Historic 1 and Future 1, as applicable, also are included.

Q. What cost allocation method was utilized in your studies?

A. The cost allocation studies, which are set forth in Exhibits JMK1 and JMK2, generally follow the same principles utilized by PPL Electric in its restructuring filing at Docket No. R-00973954 and its most recent base rate case at Docket No. R-00943271. That is, PPL Electric continues to utilize the class maximum demand method, which is based on the highest demand imposed by each rate class on its distribution system, to allocate its demand-related distribution costs. Section V of Exhibit JMK1 and Section VI of Exhibit JMK2 present the results of studies using other demand allocation methods, as required by Question 1 of Exhibit Regs., Part IV, Section E.

Q. Please describe the distribution plant investment studies contained in Exhibit JMK3.

A. Exhibit JMK3 contains the results of two studies: (1) the subfunctionalization of distribution plant investment and expense into primary and secondary voltage components and the classification of the secondary components into customer and demand-related costs, and (2) the development of allocators for meter investment and meter reading expense, which are used in the historic and future test year cost allocation studies provided in Exhibits JMK1 and JMK2. It should be noted that the subfunctionalization and classification of distribution plant investment and expense is based on a detailed analysis of specific PPL Electric plant records and cost data. The methodologies employed in the studies are explained in Exhibit JMK3 and the results of these studies are reflected in Sections A and B of Exhibits JMK1 and JMK2.

Q. In classifying its distribution plant investment and expense into customer and demand-related costs, has PPL Electric used the same methodology as that used in its last retail base rate case?

A. Yes. Consistent with the approach used in its most recent retail base rate case, PPL Electric believes that it is appropriate to continue the use of the "minimum size system" method to identify the applicable customer and demand-related cost components to determine the current cost of the "minimum size" distribution system necessary to provide reliable distribution service to its customers.

Q. Please explain Section III of Exhibit JMK3.

A. Section III of Exhibit JMK3 provides the derivation of the proposed metering and billing credits set forth in the Metering and Billing Credit Rider of PPL Electric's Tariff-Electric Pa. P.U.C. No. 201 ("Tariff No. 201"). These credits are applied to a customer's monthly distribution charges when an Electric Generation Supplier ("EGS"), licensed by the Commission, provides metering, meter reading and/or billing and collection service to a customer in lieu of PPL Electric.

The credits were derived by determining the revenue requirement, by rate schedule, for each individual service (metering, meter reading and/or *billing and collection) that could be provided to a PPL Electric customer by an* EGS. The revenue requirement calculations are based on the applicable pro forma rate base and operating expenses for the 12 months ending December 31, 2004, as set forth in Exhibit JMK2.

The proposed credits, which are shown on page 1 of Section III of Exhibit JMK3, were aggregated into the following customer groups: residential; all other secondary voltage level; primary voltage level; and transmission voltage level.

<u>Transmission Service Charge</u>

Q. Has PPL Electric proposed procedures to recover its FERC jurisdictional transmission service-related costs.

A. Yes. PPL Electric has proposed a mechanism and procedures to recover its FERC jurisdictional transmission service-related costs. The mechanism is designated the Transmission Service Charge ("TSC").

Under the TSC, PPL Electric will estimate the total costs it projects to incur, on a calendar year basis, to provide transmission service, consistent with the PJM Open Access Transmission Tariff ("OATT"), for all customers who receive Basis Utility Supply Service ("BUSS"), as defined in Tariff No. 201, from PPL Electric. The computation year will be January 1 through December 31.

Transmission service-related costs will include all costs to be incurred, on a calendar year basis, by PPL Electric to acquire transmission service, including all applicable ancillary service-related costs, on behalf of BUSS customers under the PJM OATT. These estimated costs will be recovered from all BUSS customers on a levelized kilowatt-hour basis and will be reconciled at the end of each 12-month billing period to identify any overcollections or undercollections, which will be subject to Commission review and verification. Any applicable overcollections or undercollections, including interest, will be included in the calculation of the subsequent computation year's TSC.

Distribution System Improvement Charge

Q. Has PPL Electric also proposed procedures to recover its costs for distribution system improvements and relocation projects?

A. Yes. PPL Electric also has proposed a mechanism and procedures to recover its costs associated with distribution system improvements and relocation projects. The mechanism is designated the Distribution System Improvement Charge ("DSIC").

Under the DSIC, PPL Electric will estimate the total costs it projects to incur, for a 12-month period, to enhance distribution system security, reliability, integrity, safety and long-term viability. These costs will include fixed costs (depreciation expense and pre-tax return) to be incurred by PPL Electric for the replacement deteriorated poles and underground cables; facility relocations due to state and local highway work; replacement of deteriorated and/or failed equipment on poles or at area supply substations; replacement of telemetering equipment on poles or at area supply substations; and, other reliability and security improvements. The computation period will be January 1 through December 31.

The estimated costs for distribution system improvements and relocation projects will be recovered from all distribution service customers on a levelized kilowatt-hour basis and will be reconciled at the end of each 12-month billing period to identify overcollections or undercollections, which will be subject to Commission review and verification. Any applicable overcollections or undercollections, including interest, will be included in the calculation of the subsequent computation period's DSIC.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

PPL ELECTRIC UTILITIES CORPORATION

Statement No. 6

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

A. I am employed by PPL Electric Utilities Corporation ("PPL Electric" or the "Company") as Manager-Pricing and Contract Administration.

Q. What are your principal duties and responsibilities as Manager-Pricing and Contract Administration?

A. I am responsible for Tariff Administration, which involves the development of PPL Electric retail tariff rules and regulations, and ensuring their uniform administration throughout the Company. I also direct the development of the Company's rate design function and supervise the cost of service function.

Q. What is your educational background?

A. I graduated from Michigan Technological University in 1973 with a Bachelor of Mechanical Engineering. I am a Registered Professional Engineer in the Commonwealth of Pennsylvania.

Q. Please describe your professional experience.

A. I was employed by Westinghouse Electric Corporation in 1973 and served in the Marketing Department of the Steam Turbine Division as an Application Engineer. During this period, I was involved with all aspects of the initial design and proposal preparation for large steam turbine generator sets. I also was the technical license contact for two foreign manufacturers of Westinghouse turbine generators.

In 1976, I joined PPL Electric as a construction engineer for the Susquehanna Steam Electric Station. In this position I was responsible for long-term storage and maintenance for all equipment during construction, and assembly of the Unit 1 and Unit 2 turbine generator sets.

In 1978, I was named Energy Management Engineer in PPL Electric 's Energy Conservation Department in the former Northern Division. My responsibilities included energy conservation, service coordination, and marketing with PPL's large industrial and commercial customers in that division.

In 1982, I was promoted to Senior Engineer-Research and Technical Services; later the department was renamed Industrial and Commercial (I&C) Marketing Programs. My responsibilities included residential thermal storage heating systems research, commercial and industrial HVAC and process heating/cooling applications, research and development, commercial and industrial lighting design, and educating PPL Electric's staff and customers about cogeneration.

In 1989, I was promoted to the position of I&C Marketing Manager in PPL Electric's Lancaster Division. My responsibilities included managing a staff that provided direct service and marketing contacts for all industrial and commercial customers in that Division. I was promoted to Manager-Pricing and Contract Administration in 1991, the position I now hold.

In my current position, I have been the Company's primary witness in the rate design and tariff language areas for both electric and gas service before the

Pennsylvania Public Utility Commission ("PUC" or the "Commission"). I have provided testimony in the 1994 base rate case (Docket No. R-00943271), the 1998 Electric Restructuring Case (Docket No. R-00973954), and as a witness in several formal complaint actions by customers involving interruptible service.

For PFG Gas, Inc./North Penn Gas Company, I provided rate design and tariff language support for the annual Purchased Gas clause filing (Section 1307(f)) in 1999 through 2002. I also provided written testimony and rate design in the PFG Gas, Inc./North Penn Gas Company base rate case in 2001 (Docket No. R-00005277).

In 2002, I provided rate design and written testimony before the Federal Energy Regulatory Commission (FERC Docket No. ER02-597-000), for changes to the PJM OATT for certain sub-transmission charges.

Q. Mr. Kasper, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit OGK1, which is Supplement 38 to Tariff - Electric Pa. P.U.C. No. 201 ("Tariff 201"), Exhibit OGK2, The Digest of Changes to PPL Electric Tariff 201, and Exhibit OGK3, the Bill Frequency Analysis.

Q. Mr. Kasper, what is the purpose of your testimony?

A. My testimony addresses six subjects: (1) the effects of the pro forma adjustments to historic test year book revenues and future test year budget revenues; (2) the allocation of the proposed increase among customer classes; (3) rate design; (4) other proposed tariff changes; (5) bill frequency analysis; and (6) proof of revenues.

PRO FORMA ADJUSTMENTS TO HISTORIC AND FUTURE TEST YEAR REVENUES

Q. Mr. Kasper, please describe the purpose of Schedule D-3 to Exhibits Historic 1 and Future 1.

A. Schedule D-3 in Exhibit Historic 1 shows pro forma ratemaking adjustments to book operating revenues for the historic test year ended December 31, 2003. Schedule D-3 in Exhibit Future 1 shows similar adjustments to budget revenues for the future test year ending December 31, 2004.

Q. Will you please describe the adjustments shown on Schedule D-3 in Exhibit Historic 1?

A. Page 1 of Schedule D-3 in Exhibit Historic 1 contains a summary statement of the various adjustments made to operating revenues for the test year ended December 31, 2003, as follows:

Column 1 presents total revenues per books as supplied by Mr. Schadt. Column 2 removes the revenues related to Provider of Last Resort ("POLR") service and revenues related to the recovery of stranded costs. Column 3 sets forth the combined T&D Operations revenues per books. Column 4 is the sum of all adjustments proposed to adjust the book revenues to the pro forma ratemaking level found in Column 5. Line 2, Column 4 adjusts distribution revenues to reflect the annualization of sales and revenues at December 31, 2003 and the roll-in of the State Tax Adjustment Surcharge ("STAS"). All revenues in Column 5 are pro forma. Total pro forma operating revenues for the year ended December 31, 2003 appear on Line 15, Column 5.

Q. Please describe the adjustments shown on Schedule D-3 of Exhibit Future 1.

A. Page 1 of Schedule D-3 in Exhibit Future 1 contains a summary statement of the various adjustments made to operating revenues budgeted for the year ending December 31, 2004, as follows:

Column 1 presents total budget revenues as supplied by Mr. Schadt. Column 2 removes the revenues related to POLR service and revenues related to the recovery of stranded costs. Column 3 sets forth the budgeted revenues for the combined T&D Operations. Column 4 is the sum of all adjustments proposed to bring the budgeted revenues to the pro forma ratemaking level found in Column 5. Line 2, Column 4 adjusts distribution revenues to reflect the budgeted annualization of sales and revenues at December 31, 2004 and the roll-in of the STAS. All revenues in Column 5 are pro forma. Total pro forma operating revenues at present rates for the year ending December 31, 2004 appear on Line 14, Column 5.

Q. Please continue your explanation of Schedule D-3.

A. Page 2 of Schedule D-3 for both Exhibits Historic 1 and Future 1 shows the details of the number of customers (Column 3), sales (Column 4) and revenue by each rate component (Distribution-Column 5, Distribution EDI/IDI Credits-Column 6, Transmission-Column 7, CTC-Column 8, ITC-Column 9, Energy and Capacity Column 10, and STAS-Column 12) by tariff rate schedule (Column 2). A minor adjustment was made to the transmission revenue in Column 7 to remove transmission revenues related to PPL Electric's wholesale customers. The Total Revenue by rate schedule can be found in Column 13.

Page 3 of Schedule D-3 shows, on Line 27, for both the historic test year and future test year, the total annualization adjustment by rate component.

Page 4 of Schedule D-3, for both the historic test year and future test year, shows the effect of the STAS roll-in to each of the base rate components. Each component of the base rates shown on page 3 is multiplied by one plus the respective STAS rate for the year (historic test year STAS equals 1.26%; future test year STAS equals 1.16%) to develop the base rate components shown on Page 4. The STAS revenue in Column 10 is then set to zero.

On page 5 of Schedule D-3, for both the historic test year and future test year, the revenue effect of shopping customers on the Company's transmission and energy and capacity revenues are added back for rate design purposes and proof of revenue calculations. This adjustment to revenues is for calculation purposes only, treating all customers as if they are supplied by POLR service.

Q. Please explain why you are adding back the transmission and energy and capacity revenues associated with the shopping customers.

A. All of the Company's computer models for designing rates are based on the total kWh being supplied by the Company (i.e., they are constructed using the assumption that customers are not shopping). As shown on the proofs of revenue sheets in response to Exhibit Regs., Part IV, Section C, it can be seen that, in the units column, the kWh are constant for all components of the rates, as if no customers are shopping. Accordingly, the Company calculates the summary of total revenues at the bottom of each sheet assuming it provides POLR service to all customers. This adjustment for shopping customers has no effect on the amount of the increase, allocation of the increase or the proposed rate design.

Q. Please continue with your discussion of Schedule D-3.

A. Page 6 of Schedule D-3, for both the historic test year and future test year, shows the proposed distribution revenues in Column 3, and the elimination of the EDI/IDI credits for distribution in Column 4.

Page 6A of Schedule D-3, for both the historic test year and future test year, shows the pass through of the transmission service charges that PPL Electric pays to PJM, as described in Mr. Krall's direct testimony (PPL Statement No. 4).

Q. Please explain the relationship of the percentage increase shown on Page 6A, Column 9 of Schedule D-3, for both the historic test year and future test year, and the proof of revenue calculations.

A. The total percentage increases shown by rate schedule in Column 9, page 6A are *traceable to the response to* Exhibit Regs., Part IV, *Section* C, *Calculation of* Effect *of* Proposed Rate (Proof of Revenue), for each rate schedule.

Q. Please continue with your discussion of Schedule D-3 for both the historic test year and future test year.

A. Page 7 and Page 7A of Schedule D-3, for both the historic test year and future test year, reduce the transmission and energy and capacity revenues from Page 6 and 6A by the shopping factor shown on page 7A, Column 10 to remove the revenue impact for the shopping customers that was included for calculation purposes on Page 6.

The proposed distribution rate increase is found in Column 12, Line 38, page 7, of Schedule D-3 for both the historic test year and future test year. For the future test year, the proposed increase in distribution revenues is $164,436,766.

The proposed total increase by rate schedule is found in Column 8, page 7A. These increases reflect both the requested increase in distribution revenues and an estimate of the effect of the pass through of FERC-approved transmission service charges that will begin on January 1, 2005, as described in Mr. Krall's testimony. The total proposed percent increase can be found in Column 9, line 38, Page 7A. For the future test year, the total Increase is $221,771,000 or an 8.14% increase.

ALLOCATION OF THE REVENUE INCREASE

Q. Is there a general pricing philosophy and direction that PPL Electric has followed in the allocation of the distribution increase for this case?

A. As discussed in Mr. Krall's testimony, PPL Electric established the following objectives in allocating revenue requirements:

1. Keep the increase on a total-bill basis to all residential rate schedules below 10%. "Total-bill" basis means that the allocation process included both the distribution increase proposed in this case and an estimate of the increase in

transmission service charge pass through that will occur on January 1, 2005, as compared to the total bill paid by customers.

2. Keep the increase on a total-bill basis to all rate schedules below 10%.
3. Move the relative rate of return for each rate schedule closer to the system average rate of return.

Q. How did the Company allocate the proposed rate increase among its various rate schedules?

A. In accordance with these principles, the proposed increase was allocated based on the results of the class cost of service study prepared by Mr. Kleha with the constraint that no rate schedule received an increase in total rates in excess of 10%.

Q. Why did the Company limit the increase to 10%?

A. This is the Company's first rate increase filing in almost ten years. Under normal circumstances, i.e., no rate caps, the Company's rates probably would have changed in small increments on several occasions over the past ten years. The Company's transmission and distribution rates have been subject to the rate cap, so these more modest filings could not be made. As a result, a larger percentage increase is now required. Because of this, the Company determined to limit the total amount of the increase to any rate class to 10%. This limitation also is consistent with the principle of gradualism in rate design.

Q. Applying these principles, what class revenue allocations is the Company proposing in this proceeding?

A. The allocations are summarized in the following charts. Figure 1 shows, for the major rate schedules, the proposed percentage increase in total rates. Figure 2 shows the percentage contribution of each rate schedule to the system average return, both before and after the proposed increase. Similar information for all the other rate schedules can be determined from Exhibit JMK2.

As shown on Figure 1, each rate schedule receives an increase in total rates of less than 10%, and, as shown on Figure 2, each rate schedule moves toward the system average return, in terms of percentage contribution to the system average return.

Figure 1
Percent Increase in Total Rates

	Residentiall RS	Street Lighting	General Service GS-1	General Service GS-3	Primary Service LP-4	Large Power LP-5	Interruptible Service IST	System Total
Percent Increase	9.7%	9.9%	9.9%	7.8%	6.1%	6.0%	4.8%	8.1%

Figure2
Rate of Return as a Percent of System Average Rate of Return
Present and Proposed

	Residentiall RS	Street Lighting	General Service GS-1	General Service GS-3	Primary Service LP-4	Large Power LP-5	Interruptible Service IST	System Total
Present	41%	26%	237%	269%	272%	603%	2228%	100%
Proposed	60%	31%	184%	228%	228%	275%	499%	100%

RATE DESIGN

Q. Please describe the overall rate design approach in PPL Electric's proposed Tariff No. 201, Supplement 38, provided as Exhibit OGK1.

A. The primary objective of the rate design was to develop rate schedules that would produce the requested revenues when applied to forecasted conditions for the 12 months ending December 31, 2004.

Q. How was the cost of service reflected in the rate design?

A. In the analysis of the cost of service for distribution operations, there are only two types of costs, customer and demand. In the presently effective residential rate (Rate Schedule RS) and the small general service rate (Rate Schedule GS-1), however, a large portion of the distribution revenue is being collected through usage, or kWh charges. In this filing, PPL Electric is proposing to move toward distribution rates that are more demand and customer dependent and less energy dependent. This change is more reflective of how costs are incurred by a distribution company.

<u>Residential Rate Schedules</u>

Rate Schedule RS-Residential Service:

Q Are there any major changes proposed to the Residential Rate –Rate Schedule RS?

A. The Company is proposing to increase the customer charge from $6.47 to $12.20 per month to more accurately reflect the cost of service. This new design also incorporates the first 200 kWh of distribution service into the customer charge. The total number of kWh steps within the rate remains the same at three, with no charge per kWh for the first 200 kWh. The second kWh step includes usage from 201 kWh up to 800 kWh, as does the present rate structure; the third step applies to usage over 800 kWh.

Residential Time of Day-Rate Schedule RTD

Q. What changes are being proposed for Residential Time of Day, Rate Schedule RTD?

A. No rate design changes are being proposed for this rate schedule.

Residential Thermal Storage-Rate Schedule RTS

Q. What changes are being proposed for Residential Thermal Storage, Rate Schedule RTS?

A. No rate design changes are being proposed for this rate schedule.

General Service and Large Power Primary Voltage (12,000 volts) Rates

Small General Service – Rate Schedule GS-1

Q. What changes are being proposed for Small General Service, Rate Schedule GS-1?

A. The structure of Rate Schedule GS-1 remains essentially unchanged with a customer charge that includes the first 5 kW of the billing demand. PPL Electric is proposing to increase the customer charge to include the full demand charges associated with 5 kW. In the present rates, the customer charge is set too low and only recovers demand charges associated with 4 kW.

Large General Service – Rate Schedule GS-3

Q. Are there any changes proposed to Large General Service, Rate Schedule GS-3?

A. Yes. In keeping with the general direction of moving toward more customer and demand-oriented rates and away from kWh-based rates, proposed Rate Schedule GS-3 will recover 95% of the overall distribution revenue through demand charges.

The present Rate Schedule GS-3 rate recovers 85% of the overall distribution revenue through demand charges.

Large Power Firm Service at 12,000 Volts – Rate Schedule LP-4

Q. Are there any changes proposed to Large Power Service, Rate Schedule LP-4?

A. Yes. For Rate Schedule LP-4, kWh charges have been eliminated and all distribution revenue will be collected through demand charges

Large Power Interruptible Service at 12,000 Volts – Rate Schedule IS-P

Q. Are there any changes proposed to Large Power Interruptible Service, Rate Schedule IS-P?

A. No rate design changes are being proposed for this rate schedule.

<u>Large Power Customers with Service at 69,000 Volts</u>

Firm Power Rate-Rate Schedule LP-5

Q. Are there any changes proposed to the distribution rate for Large Power Service, Rate Schedule LP-5?

A. No distribution rate increase is proposed for this rate schedule. However, the Company is proposing to eliminate the transmission credit for 230,000 volt service. No customers currently receive service at this voltage level.

Interruptible Power Rate – Rate Schedule IS-T

Q. Are there any changes to the distribution rate for Large Power Interruptible Service, Rate Schedule IS-T?

A. The Company is proposing to reduce the distribution rate in this rate schedule.

Firm Power, Rate Schedule LP-6

Q. Are there any changes proposed for Large Power Service, Rate Schedule LP-6?

A. The Company is proposing to reduce the distribution rate in this rate schedule.

Electric Propulsion, Rate Schedule LPEP

Q. Are there any changes proposed for Electric Propulsion, Rate Schedule LPEP?

A. The Company is proposing to eliminate the credit for non-utilization of the Company's 69,000 volt or 138,000 volt "3 phase" facilities.

TARIFF CHANGES

Q. Would you briefly describe the contents of Exhibit OGK2?

A. This exhibit, which is entitled "Digest of Proposed Changes Requested in Supplement No. 38 to Tariff – Electric Pa. P.U.C. No. 201," contains a summary of the Company's proposed rules and rate changes. A copy of this digest is provided to all PPL Electric employees who have responsibility for administration of the electric tariff.

Rule Changes

Q. Is there a comprehensive list of changes that summarizes all the proposed tariff changes?

A. Yes. This list can be found in the summary starting on page 2 of Exhibit OGK1, Supplement No. 38 to PPL Electric's Tariff – Electric Pa. P.U.C. No. 201.

Q. Are there any proposed changes in the minimum revenue guarantees provision?

A. Yes. Existing Tariff Rules 3-B and 4-B require a revenue guarantee for line extensions and speculative line extensions, respectively. The Company is proposing to revise "minimum revenue guarantee" to "minimum distribution revenue guarantee" in each of these rules. This change will clarify that only distribution revenue will be considered for the revenue guarantee.

Q. Are there any changes proposed to the provision for Extension for Individual Service?

A. Yes. Line extensions under Rule 3-A are intended to include only distribution system construction consisting of more than the normal service facilities, which are transformers, transformer devices, service drop and meter. However, the existing language in this rule does not provide clear distinction between facilities extended along the route of normal distribution system development and facilities installed solely for a customer. The Company is proposing to revise Tariff Rule 3-A to clarify that a service extension begins at the point where an extension departs from the normal route of distribution system development and is installed as a service extension solely for the customer. This change is necessary to address situations where a customer's property line is significantly remote from the route of the distribution system, such as up a mountain trail.

Q. Are there any changes proposed in the "Speculative Service Extensions" provision of Tariff Rule 4?

A. Yes. Existing Tariff Rule 3-F(3) provides definitive authority to charge differential billing if there is a revenue guarantee shortfall for a line extension. Currently, there is no language in Tariff Rule 4-B that provides similar authority for speculative line extensions. In the administration of revenue guarantees for both speculative and non-speculative line extensions, the intent is to charge differential billing in the event of a revenue guarantee shortfall. Therefore, the Company is proposing to add language to Tariff Rule 4-B tracking language from Tariff Rule 3-F(3) that clarifies the Company's authority to charge differential billing.

Q. Are there any changes proposed to the "Alternate Service" provision of Tariff Rule 4?

A. Yes. Under the present Tariff Rule 4-D, the Company will install facilities for an alternate source of service when the customer agrees to compensate the Company for the estimated cost of the additional facilities maintained for the alternate service. The current language in this tariff rule addresses current costs, but does not address potential future costs. The Company is proposing to revise Tariff Rule 4-D to clarify that the customer is required to compensate the Company for all costs incurred to provide the alternate service, including the future estimated costs of continuing to provide the alternate service.

Q. Are there any changes proposed to the "Use of Service" provisions of Tariff Rule 5?

A. Yes. Tariff Rule 5-A is being revised to clarify the customer's responsibility beyond the point of delivery. It is the customer's responsibility to purchase and install protective devices and alternate power supplies to protect the customer's facilities and property. This change is necessary to clarify the customer's responsibility in this area.

Q. Are there any changes proposed to Rule 6A – Standby Service for Qualified Facilities?

A. Yes. The present version of Tariff Rule 6A defines "Back-up Power" as electric energy or capacity supplied by the Company to replace energy or capacity regularly supplied by the QF's equipment when such equipment is not available during an outage for other than prescheduled maintenance or fuel supply disruptions. Back-up Power is limited to 1,314 hours during the most recent 12-month period. Tariff Rule 6A further provides that energy and capacity supplied beyond 1,314 hours is supplied as Supplementary Power. However, the definition of an outage in Tariff Rule 6A must be clarified in order to determine whether power is being supplied as back-up power or as supplementary power. To clarify this definition, the Company is proposing to include language stating that an outage is the forced interruption of the QF's entire generation output.

Q. Are there any changes proposed to the "Temporary Service" provision in Tariff Rule 7?

A. Yes. Temporary service is provided under Rule 7-A for less than one year or for a year or more when the Company must install facilities that will be used solely for a service that is known to be limited in duration. The Company is proposing to revise Tariff Rule 7-A to include seasonal service, which is service for less than one year for which the Company is requested to leave the facilities in place for subsequent reconnection the following years. This change is necessary because customers requesting annual connects and disconnects for seasonal use do not fully compensate the Company for the cost of facilities installed. Specifically including seasonal use customers within the definition of "Temporary Service" in Tariff Rule 7-A will help to ensure that the Company is fully compensated for the cost of facilities installed and maintained for annual use.

Q. Are there any proposed changes in Tariff Rule 8 - Measurement of Service?

A. Yes. There are two clarifications to this tariff rule. First, Tariff Rule 8-B (Metering Installations) currently provides that service at each point of delivery is metered through one or more meters as required by the applicable rate schedules. The Company is proposing to revise this tariff rule to clarify that measurement from separate points of delivery are not combined for billing purposes. Second, Tariff Rule 8-C currently allows the Company to determine kilowatt hours and billing demands by computation instead of measurement for installations having a fixed load or demand value controlled to operate for a definite number of hours during a billing period. The Company is proposing to revise this tariff rule to require an electric service contract for billing under this unmetered service.

Q. Are there any changes proposed to Tariff Rule 10 – "Disconnection and Reconnection of Service"?

A. Yes. Tariff Rule 10-C currently sets forth conditions for reconnection of electric service, including the full payment of charges for energy used, but not metered, all costs of the Company's investigation and any property damage associated therewith. The Company is proposing to revise this tariff rule to specify that those charges include, but are not limited to: the Company's cost of tampering investigations, inspections, billing, and corrective action on unsafe equipment.

Rider Changes

Q. Does PPL Electric propose any changes in the State Tax Adjustment Surcharge ("STAS")?

A. Yes. The Company is proposing to replace the current single STAS rate with a two-part rate. This change is required because the taxes identified below in Part 1 of the STAS are applied only to distribution charges, while the Gross Receipts Tax in Part 2 is applied to all bill components.

- Part 1 will include changes to Capital Stock Tax, Corporate Income Tax, and Public Utility Realty Tax, which will be applied to the Distribution component of the bill.
- Part 2 includes the Gross Receipts Tax, which will be applied to all components of the bill.

Q. Does PPL Electric propose to continue the Economic Development Initiatives/Industrial Development Initiatives ("EDI/IDI") credits for distribution service?

A. No. PPL Electric is proposing to eliminate these credits for distribution service. These credits were scheduled to start phasing out beginning on January 1, 1998, and to be completely eliminated by January 1, 2000. In its 1998 restructuring case, the Company proposed to eliminate these credits immediately. The settlement in that case required PPL Electric to maintain the credits through the rate cap periods and unbundle the credits into components of distribution, CTC, and energy & capacity. Later, as part of the Company's securitization filing (Docket No. R-00994637), *the credit for CTC was split into ITC and CTC.*

Because the distribution and transmission rate cap will expire at the end of 2004, the Company is proposing to eliminate the EDI/IDI credits for distribution service at that time. The remaining components of the EDI/IDI credits will be maintained through the end of the generation rate cap period.

Q. Are there any changes proposed to the Optional Power Quality Services Rider?

A. This "experimental" Rider was filed with a December 31, 2004 termination date. Because there are no contracts between the Company and any customers for this service, it will be terminated on December 31, 2004.

Q. Are there any changes proposed to the Sustainable Energy Fund Rider?

A. Yes. The Company is proposing that the expiration date be extended to no later than December 31, 2009. The Company is not proposing any change to the rate of 0.01 cents per kWh. This rider is discussed in more detail in Mr. Dahl's testimony (Statement No. 7).

Q. Are there any proposed changes to the Metering and Billing Credit Rider?

A. Yes. The Company is proposing that the Metering (excluding residential and general service customers), Meter Reading, and Billing and Collection credits be adjusted, based on current cost of service data. This rider is discussed further in the testimony of Mr. Kleha (Statement No. 5).

Q. Are there any changes proposed to the Demand Side Initiative Rider?

A. Yes. The Company is proposing that this "experimental" rider be extended to January 1, 2008 to continue providing industrial and commercial customers with an option to adjust their load requirements in response to market prices. This rider is discussed further in Mr. Krall's testimony (Statement No. 4).

Q. Are there any proposed changes to the Demand Side Response Residential Rider?

A. Yes. The Company is proposing that this "experimental" rider be extended to September 30, 2007 to continue providing residential customers with an option to adjust their load requirements in response to market prices. This rider is discussed further in Mr. Krall's testimony (Statement No. 4).

Q. What is the proposed Distribution System Improvement Charge ("DISC")?

A. The DISC is a proposed method for recovery of the fixed costs of investment in the delivery system for improvements and relocations to enhance system security, reliability, integrity, safety and long-term viability. This charge is discussed in Mr. Krall's testimony (Statement No. 4) and Mr. Kleha's testimony (Statement No. 5).

Q. What is the proposed Transmission Service Charge ("TSC")?

A. Consistent with the authority set forth in its current tariff, charges that PPL Electric pays to PJM for transmission service are passed through to retail customers. The TSC is a proposed mechanism for this pass through with an estimated initial charge of $0.00564 per kWh applied to all kWh. This proposal is discussed further in Mr. Krall's testimony (Statement No. 4) and Mr. Kleha's testimony (Statement No. 5).

Rate Schedule Changes

Q. Are there any restrictions being proposed for any of the Company's rate schedules?

A. Yes. The Company is proposing that for Rate Schedules GS-1 (secondary), GS-3 (primary), and LP-4 (12,470kV), new services at voltage levels higher than the specified service voltage level will not be accepted after June 1, 2004.

Q. Throughout its tariff, PPL Electric continues to publish the expired history of CTC, ITC, energy & capacity and other rates and/or riders. Is PPL Electric proposing to continue this practice?

A. No. The Company is proposing to delete, in the compliance filing which will be submitted at the end of this case, all of the expired rates for distribution, CTC, ITC, energy & capacity and other expired rates that are no longer effective. In addition, the Company also is proposing to delete the previous year's expired rate with each annual CTC/ITC reconciliation filing. These proposals will reduce the volume of the tariff and reduce the administrative burden of maintaining this history. As always, the Company will continue to maintain past tariff sheets that can be obtained on request.

BILL FREQUENCY ANALYSIS

Q. Mr. Kasper, please explain the methods used to calculate the annual revenue effects of the proposed rates.

A. Bill distributions and other summaries of billing quantities for all rates are provided for the 12 months ended December 31, 2003 in Exhibit OGK3. Both present and proposed rates were applied to the corrected billing quantities. The results of these calculations were then used to obtain adjusted rate class revenue for the period ended December 31, 2003 and for the budgeted rate class revenue for the period ending December 31, 2004. In this way, the Company derived the total annual revenue effect and the effect by rate classes. Increases also were assigned to the late payment charge and to the annualized revenue adjustment.

PROOF OF REVENUE

Q. Please explain the proof of revenue or bill frequency analysis.

A. The response to Exhibit Regs., Part IV, Section C contains a bill frequency analysis which details, by rate class, the billing units for each type of charge in PPL Electric's existing and proposed tariff. In Column 2, there is a summary of the annual billing units for each class. This summary includes total customer, total kW, or total kWhs in the specific block. Column 3 contains the price per unit at current rates. Column 4 shows the total revenue for that block. The percentage increase in proposed rates over current rates is at the bottom of each page. This percentage is used to calculate the dollar revenue increase for all classes. The results of the proof of revenue can be found on Page 6 and 6A of Schedule D-3 of Exhibits Historic 1 and Future 1.

Q. Have you compared customer bills before and after the proposed increase?

A. Yes, Bill comparisons for selected rate schedules can be found in response to Exhibit Regs., Part IV, Section D. Various bill comparisons were completed utilizing average usage and a selected range of residential and general service usage.

Q. Does this conclude your testimony?

A. Yes, it does.

DOCUMENT

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

PPL Electric Utilities Corporation

Statement No. 7

Direct Testimony of Timothy R. Dahl

Direct Testimony of Timothy R. Dahl

Q. Please state your full name and business address.

A. My name is Timothy R. Dahl and my business address is: PPL Electric Utilities, 827 Hausman Road, Allentown, PA 18104.

Q. What is your position at PPL Electric Utilities ("PPL Electric" or "Company")?

A. I am the Manager - Regulatory Programs & Business Services in PPL Electric's Customer Services Department. I report directly to the Vice President – Customer Services.

Q. How long have you worked at PPL Electric Utilities?

A. I have worked in a variety of capacities at PPL Electric for nearly 26 years.

Q. What are your current responsibilities?

A. I am responsible for managing the Company's universal service, compliance, quality assurance and Customer Choice programs. I manage the budget, staffing, operations and processes, management controls, performance and Public Utility Commission ("PUC" or the "Commission") reporting requirements for the following universal service programs: OnTrack, WRAP, Operation HELP, and CARES. I manage all facets of compliance and quality assurance to ensure adherence to PUC regulations, timely responses to customer complaints filed with the

Commission, and improvements in policies and processes to strengthen performance. I serve as the primary liaison between the Company and the PUC's Bureaus of Consumer Services and Conservation, Economics and Energy Planning, Pennsylvania Department of Public Welfare ("DPW"), and Pennsylvania Office of Consumer Advocate regarding all aspects of low-income programs, Chapter 56 regulations, and policy issues related to residential customers. I direct all aspects of PPL Electric's consumer education efforts for Customer Choice and serve as the primary liaison between the Company and the PUC on that effort. I serve as the Company's primary advocate regarding federal funding for the Low Income Home Energy Assistance Program ("LIHEAP"). I act as PPL Electric's liaison with the DPW regarding the development and implementation of the State Plan for LIHEAP. I oversee and direct PPL Electric's customer outreach efforts during major storm emergencies. I respond to media requests (electronic and print) regarding PPL Electric's universal service programs, compliance with Chapter 56 regulations and LIHEAP. I direct all goal-setting for the Regulatory Programs & Business Services staff that administers the universal service programs, compliance and quality assurance initiatives, and Customer Choice program. I provide communications with internal staff regarding Company, department and section goals, performance results, expectations and policies.

Q. What is your work experience, professional associations, and educational background?

A. During my nearly 26-year career I have held various staff and supervisory positions in Marketing & Economic Development, Public Affairs and Customer Services. In my current position as Manager – Regulatory Programs & Business Services, I oversee and direct a work group of 18 people, including staff professionals and administrative support. I have participated in a variety of professional, industry, and consumer organizations such as the Society of Consumer Affairs Professionals, Edison Electric Institute ("EEI"), Energy Association of Pennsylvania ("EAP"), National Low Income Energy Consortium, National Fuel Fund Network, and the PA Natural Gas Universal Service Task Force. Over the years I have chaired committees at both EEI and EAP. During the restructuring of the electric industry in Pennsylvania, I represented PPL Electric on various Commission-sponsored working groups (e.g., low income) that developed policies and procedures. I have spoken numerous times at a variety of energy, consumer and regulatory conferences and workshops. I hold BA and MA degrees in Political Science.

Q. What is the purpose of your direct testimony regarding PPL Electric's request for increased rates?

A. My purpose is to describe and explain the Company's proposal regarding the funding and implementation of its universal service programs, particularly OnTrack and the Winter Relief Assistance Program ("WRAP"). OnTrack provides affordable payment plans and arrearage forgiveness and WRAP offers free weatherization measures and energy conservation education.

I will outline the Company's proposal to implement a new program called the Community Betterment Initiative ("CBI"). This program would address issues such as economic development, affordable housing and downtown improvements. PPL Electric would link the CBI to a variety of state-sponsored initiatives aimed at improving Pennsylvania's economic well being.

I also will describe and explain PPL Electric's proposal regarding the continued funding of its Sustainable Energy Fund ("SEF"). The Company agreed to fund the SEF as a result of its 1998 Settlement Agreement in its restructuring case. The SEF promotes the development and use of renewable energy and clean energy technologies and energy conservation and efficiency.

Q. Are you sponsoring any exhibits as part of your direct testimony?

A. Yes. I am sponsoring the following exhibits in this proceeding:

Exhibit #	Description
TRD1	Fact Sheets of Universal Service Programs
TRD2	List of Agencies that Administer PPL Electric's Programs
TRD3	Summary of Sustainable Energy Fund Projects

Q. What types of programs does PPL Electric offer for low-income customers.

A. PPL Electric has been an industry leader in implementing programs for low-income customers for nearly twenty years. The Company currently offers four programs that target low-income customers: OnTrack, WRAP, Operation HELP, and CARES. In general terms, OnTrack offers a *reduced payment plan and arrearage forgiveness*; WRAP *provides free* weatherization measures and energy conservation education; Operation HELP pays for home energy bills; and CARES is a referral service to Company and community programs. PPL Electric also promotes the *availability of* LIHEAP. *Funded by the federal government and* administered by the Pennsylvania DPW, LIHEAP provides energy assistance grants for low-income households. The program normally runs from November through March. See Exhibit TRD1 for a more detailed explanation of PPL Electric's four universal service programs.

Q. When did PPL Electric begin its four low-income programs?

A. PPL Electric implemented CARES in 1980, Operation HELP in 1983, WRAP in 1985, and OnTrack in 1994. The Company began promoting the availability of LIHEAP when the program started in the early 1980s.

Q. How does PPL Electric implement and administer these universal service programs?

A. The Company works closely with a variety of community-based organizations ("CBOs" or "agencies") throughout its 29-county, 10,000 square mile service area. The agencies are strategically located, have extensive experience in serving the low-income population, and provide other benefits to OnTrack customers. The partnership between PPL Electric and the CBOs is critical to the ongoing delivery of the Company's low-income programs. Exhibit TRD2 includes a list of the various CBOs that help administer PPL Electric's programs.

Q. What are the current annual funding levels for PPL Electric's universal service programs?

A. The estimated annual funding levels in 2004 for the Company's four major programs appear in the following table:

Program	**Annual Funding Level**
OnTrack	$11,700,000
WRAP	5,700,000
Operation HELP	900,000
CARES	110,000
Total	$18,410,000

Funding for OnTrack and WRAP comes from rates paid by all residential customers. Funding for Operation HELP comes entirely from donations by PPL Electric, its customers and employees. There is no specific operations and maintenance budget for CARES. The estimated expenditure of $110,000 covers wages and benefits ($50,000) and CARES Credits ($60,000). A unique feature of PPL Electric's CARES program is a provision for CARES Credits, which come from a corporate contribution to Operation HELP. The Company's Customer Programs Directors use these credits to help pay electric bills for customers whom have run out of options.

Q. What has PPL Electric done to promote the availability of LIHEAP?

A. LIHEAP is an important energy assistance program that provides grants to hundreds of thousands of low-income Pennsylvania households annually. Promoting LIHEAP improves the effectiveness of the agencies that administer the Company's universal service programs. The CBOs can either use LIHEAP to provide additional assistance or to substitute a LIHEAP grant for an Operation HELP grant. This coordination provides services to more households.

To promote LIHEAP, PPL Electric sends a bill insert to all customers, provides program information to its Customer Service Representatives, conducts special mailings to low-income households and implements an outreach calling campaign that targets income eligible customers. Company representatives also work with local CBOs to promote LIHEAP.

Q. What have been the major benefits of these programs?

A. PPL Electric believes that its universal service programs provide a variety of benefits to both customers and the Company. The following table shows the number of participants or customers assisted by OnTrack, WRAP and Operation HELP.

Program	2000	2001	2002	2003
OnTrack	9,803	9,099	10,919	12,420
WRAP	2,879	2,059	2,555	2,890
Operation HELP	2,491	2,314	2,641	2,660
Total	15,173	13,472	16,115	17,970

As noted above, PPL Electric has taken an active role in informing low-income customers about LIHEAP and its requirements. The following table shows the number of PPL Electric customers who have received LIHEAP grants over the past four years.

Program	1999-2000	2000-2001	2001-2002	2002-2003
LIHEAP Customers	8,334	12,622	12,065	13,906
LIHEAP Grants	$2,757,225	$4,277,376	$3,311,809	$3,920,483

From a customer's perspective, key benefits of the universal service programs include avoiding shutoffs for non-payment, providing an affordable electric bill, lowering energy bills, improving living comfort and receiving services from other assistance programs. From PPL Electric's perspective, key benefits include improving customer satisfaction, avoiding collection expenses, reducing complaints to the PUC, helping to manage overdue receivables and building partnerships with CBOs.

Q What has been PPL Electric's overall experience with its low-income programs?

A. PPL Electric believes that its universal service programs have provided a net benefit in terms of addressing customer needs, improving customer satisfaction, managing costs and establishing effective partnerships with CBOs, regulators and other public interest groups.

The universal service programs are not static; they are continually changing and evolving. The introduction of new technology, turnover of agency caseworkers, increasing customer expectations, additional work processes and new regulatory requirements are just some of the challenges. However, PPL Electric has the leadership, personnel and experience to respond effectively to these challenges. The Company is committed to continuing the implementation of its universal service programs in ways that meet the needs and expectations of customers, regulators, employees and senior management at PPL Electric.

Q. Does PPL Electric intend to deliver these programs in the same manner in 2005?

A. Yes. The Company will continue to rely on the experience of the CBOs and other contractors that have administered the programs for years. This collaboration is essential to the effective delivery of programs and services to low-income households. This model of delivery has been effective and PPL Electric will continue its efforts to work with the CBOs and contractors to improve policies and procedures. The Company's commitment to continuous improvement clearly applies to the universal service programs.

Q. Does PPL Electric plan to offer any new features for the programs in 2005?

A. Yes. *If approved by the Commission, the Company intends to make two* changes affecting WRAP and OnTrack. First, with respect to WRAP, the Company proposes to continue installing solar water heating applications for low-income customers. As part of the 1998 Settlement Agreement in its restructuring case, PPL Electric agreed to conduct a pilot for solar water heating and photovoltaic installations that targeted low-income customers. Using trained and certified installers from four CBOs (i.e., Community Action Program of the Lehigh Valley, Commission on Economic Opportunity of Luzerne County, SEDA-COG in Snyder County and the Lancaster County Community Action Program), 45 solar water heating applications and 44 photovoltaic applications were installed throughout PPL Electric's service area. The Company had the units installed free of charge for customers who agreed to participate and who met the pilot requirements (e.g., homeowners, sufficient kWh usage, proper roof orientation, structural integrity and no shade trees).

Regarding OnTrack, PPL Electric proposes to eliminate its restriction on subsidized housing participation. Currently, a customer living in subsidized housing qualifies for OnTrack if he or she pays at least

$150 monthly in rent. Given PPL Electric's fixed annual budget of $11.7 million for OnTrack, the Company restricted the participation of subsidized housing customers in order to provide OnTrack benefits to low-income customers who receive fewer benefits. The Company intends to remove this restriction to be consistent with the PUC's Policy Statement on Customer Assistance Programs and with the practices of the other electric and gas utilities in Pennsylvania that offer programs like OnTrack.

Q. What levels of annual funding does PPL Electric propose for its low-income programs in 2005 and beyond?

A. If approved by the Commission, the Company proposes to increase annual funding for OnTrack and WRAP by $3 million and $1 million, respectively. The funding for Operation HELP will increase modestly each year as a result of the Company's efforts to solicit donations from customers and employees. Funding for CARES will increase slightly to reflect changes in wages and benefits for the Customer Programs Directors and other support personnel. The following table shows the proposed funding for PPL Electric's universal service programs.

Program	2004	2005	% Increase
OnTrack	$11,700,000	$14,700,000	25.6%
WRAP	5,700,000	6,700,000	17.5%
Operation HELP	900,000	922,500	2.5%
CARES	110,000	112,000	1.8%
Total	$18,410,000	$22,434,500	21.9%

Although PPL Electric proposes to start collecting the $4 million increase in funding for OnTrack and WRAP through electric rates effective January 1, 2005, the Company proposes to ramp up its expenditures over a three-year period of time (2005 - 2007). The Commission approved this same approach in 1998 when PPL Electric increased its funding for OnTrack and WRAP as a result of the Settlement Agreement in its restructuring case. A ramp-up period allows for a smoother transition, reduces customer complaints, allows the CBOs to adjust their processes and results in a more effective delivery of services. The Company would "escrow" the difference (total revenue collected minus program expenditures) and would spend it in future years. PPL Electric proposes the following ramp-up of expenditures.

Program	2005	2006	2007	2008	2009	2010	2011
OnTrack	$12.7M	$13.7M	$14.7M	$15.7M	$15.7M	$15.7M	$14.7M
WRAP	$6.0M	$6.5M	$6.7M	$7.0M	$6.9M	$6.9M	$6.7M
Total	$18.7M	$20.2M	$21.4M	$22.7M	$22.6M	$22.6M	$21.4M

The above-proposed expenditure schedule would compensate for the under expenditure in 2005 and 2006 by expending these dollars in years 2008 – 2010. This approach allows for a seamless transition while ensuring the full expenditure of collected funds for OnTrack and WRAP.

Q. What is the basis for PPL Electric's proposal to increase funding for OnTrack?

A. The Company's proposal to increase funding by 25 percent (i.e., $11.7 million to $14.7 million) would allow the Company to have a range of 15,000 - 17,000 low-income customers enrolled in OnTrack. Not only does this level of funding appear to match customers' need for the program, it also would have a manageable impact on the current delivery structure for OnTrack. By ramping up expenditures over a period of three years, the OnTrack CBOs could absorb the additional workload with minimal interruption. Any appreciably higher level of funding would require additional hiring by the CBOs, increased administrative costs, more technology costs for computers and technical support and a likely increase in the number of CBOs.

Q. What is the basis for PPL Electric's proposal to increase funding for WRAP?

A. WRAP is clearly a long-term commitment for PPL Electric. Although the Company has provided weatherization measures and services to over 50,000 households during the twenty-year history of WRAP, it estimates that approximately 43,000 additional households could benefit from the program. The proposed increase in funding for WRAP (from $5.7 million to $6.7 million) would allow PPL Electric, based on historical costs and the types of WRAP jobs (e.g., full cost, low cost or baseload), to serve an average of 3,200 customers annually. This represents an increase of 12 percent over the Company's average production from 2000 - 2003. It also would permit PPL Electric to offer solar water heating as a standard WRAP measure.

Q What has been PPL Electric's history of community and economic development?

A. Community and economic development and business expansion have been important objectives for PPL Electric for many years. Over time, PPL Electric has continued to refine its community and economic development strategies. These strategies include partnerships with local economic development groups, many of which PPL Electric has nurtured and helped to grow into very capable organizations.

PPL Electric's current programs center on providing leadership to these groups and on programs that help them execute their strategies. PPL Electric's approach is very hands on, starting with a network of eight Regional Community Relations Directors ("RCRDs") who work on a daily basis in key leadership roles with their fellow community leaders throughout Central and Eastern Pennsylvania. The Company works to build the long term economic health of our communities from the ground up.

The Company maintains an excellent searchable database of available properties on a web site that also offers detailed data for the region of any site selected. PPL Electric advertises the site nationally and site location consultants utilize it regularly. PPL Electric's allies can use this database as their own and have their local part of the overall file extracted and provide it to anyone who requests site information from their local web site.

Q. What types of programs does PPL Electric offer?

A. PPL Electric offers a variety of programs designed to support local communities. For instance, the Company helps to underwrite fees for the Accredited Economic Development Organization Program of the International Economic Development Council. This program also supports professional development and training for economic development staff in local communities. The Company provides funding for studies to identify new industrial sites or to determine the suitability and development cost of a specific industrial site, including the reuse of Brownfield sites.

PPL Electric underwrites 50 percent of the interest charges on funds borrowed by an eligible economic development organization up to a maximum of $30,000 per year to construct or acquire qualifying speculative industrial buildings. The interest subsidy continues until the local organization sells or leases the building, up to a maximum of three years.

PPL Electric utilizes its land acquisition program to stimulate the purchase and development of land suitable for corporate office and/or industrial use by eligible nonprofit economic development organizations. The Company reviews proposals and makes selections on a competitive basis. Local organizations must submit well-planned projects that have a high potential for successful development.

PPL Electric's Blue Ribbon Marketing Program provides financial and technical assistance for prospect development and marketing activities. Local and regional economic development organizations can receive Blue Ribbon awards for as much as 75 percent of the cost of each marketing initiative, up to a maximum of $7,500 per project. Award eligible activities include regional marketing campaigns, web site design or enhancements, strategic marketing studies and plans, coordinated prospecting events and community visioning exercises.

All of these specific community programs supplement PPL Corporation's public and charitable contributions. The highest priorities for funding are capital campaigns for human service organizations and higher education, seed money for emerging social issues and federated drives such as United Way and Operation HELP. Major non-cash community contributions from PPL Electric include four environmental centers that attract over two million visitors annually, extensive education leadership programs, a computer donation program and the Community of Volunteers to support approximately 1,500 employees who generously volunteer their time to hundreds of community causes.

Q. What have been the major accomplishments of these programs?

A. Since 1995 major projects supported by PPL Electric have helped to create over 10,000 jobs. In the last five years, 92 economic development professionals have receive scholarships to further their training, four shell buildings have received subsidies, 16 site feasibility studies received funding, nine local industrial parks received interest free loans and PPL Electric issued 120 Blue Ribbon Marketing Partnership grants.

Q. Does PPL Electric plan to offer any new community and economic development programs in 2005?

A. Yes, PPL Electric proposes to implement a new program called the Community Betterment Initiative ("CBI").

Q. What is the primary purpose of the CBI?

A. The purpose of the CBI is to assist community development organizations and human service agencies in addressing local needs by providing grant funds that would leverage matching funds from the state for targeted programs. The CBI also would support local efforts to improve economic prosperity.

Q. What is the proposed level of funding for the CBI?

A. The Company recommends funding of $2 million annually for a period of three years (2005 - 2007). The funding would be a combination of ratepayers ($1 million) and PPL Corporation's shareholders ($1 million).

PPL Electric would revisit the CBI in mid-2007 to determine if the program should continue beyond the initial three-year commitment.

Q. What are the key features of the Community Betterment Initiative?

A. The CBI would be a two-pronged program targeting community and economic development programs and affordable housing. To maximize its impact and leverage, PPL Electric would also attempt to link the CBI to the state's Comprehensive Economic Stimulus Programs. This linkage would provide a variety of programs to enhance community prosperity, ranging from traditional economic development efforts to affordable housing to downtown marketing programs. The CBI could provide a portion of the required community matching funds for projects that meet the state's expectations of job creation, the presence of an effective development plan and significant leverage and commitment from strong local partners. Similarly, CBI funding would leverage state funding earmarked for affordable housing initiatives by providing much needed matching funds.

Q. In general terms, how would the CBI process work?

A. PPL Electric would use a competitive process whereby community organizations would submit detailed responses to requests for proposals ("RFP"). The Company would evaluate the proposals and award CBI grants based on the following criteria:

- Well-written and responsive to the RFP's requirements.
- Existence of, commitment to and implementation of a comprehensive community plan.
- Proven track record of implementation success of community programs.
- Solid reputation and credibility within the community.

Q. What would be the timing for the CBI process?

A. If approved for implementation and funding by the Commission, PPL Electric would send letters of invitation to appropriate community organizations in early February 2005. The Company would conduct and complete the information meetings by the end of March. Organizations interested in competing for a CBI grant would submit their RFPs by the end of April. PPL Electric would evaluate the proposals and select grantees by mid-May. The Company would release the funding to the grantees by the end of June.

Q. What types of community organizations would be eligible for CBI grants?

A. PPL Electric proposes to offer CBI grants to nonprofit organizations in local communities. They would include a broad range of economic development groups and human service agencies that serve low-income households. These organizations would have to submit proposals that meet the focus of the CBI program (i.e., community and economic development, affordable housing and downtown improvements).

Q. Why is PPL Electric proposing the Community Betterment Initiative?

A. PPL Electric clearly has a vested interest in supporting efforts to improve the prosperity of the territory it serves in Pennsylvania. More jobs, a sounder economy, infrastructure improvements and strengthened communities help everyone. PPL Electric long ago recognized the linkage between the prosperity of its service area and the prosperity of the Company. PPL Electric is a Pennsylvania company with well-established roots in the state. Most of our employees were born here, educated here and live and work here. PPL Electric and its employees are an important part of the fabric of society in central and eastern Pennsylvania. The Company has a role in helping to improve the quality of life and in making the state a desirable place to live, work and raise a family.

Over the years PPL Electric and its employees have done much to support and often lead efforts to reach these objectives. From providing safe, reliable and competitively priced electricity to respecting and protecting the environment to providing good jobs and to participating in a myriad of volunteer activities, PPL Electric has made a serious commitment to making Pennsylvania a better place to live and work. The Company also recognizes that there is strength in numbers and has worked cooperatively and effectively with partners from both the public and private sectors.

PPL Electric has the resolve and commitment to continue these efforts in the future. The Community Betterment Initiative is simply another manifestation of the Company's well-documented efforts to work with local organizations in addressing their needs and concerns. They still view PPL Electric as a vital and necessary partner. PPL Electric knows from its successful efforts with the Community Partnership Program that a modest investment in the CBI should return solid benefits to local communities.

Q. What is the Sustainable Energy Fund ("SEF")?

A. In the Joint Petition for Full Settlement of PP&L Inc.'s Restructuring Plan and Related Court Proceedings, Docket No. R-00973954, dated August 12, 1998, PPL Electric agreed to establish a Sustainable Energy Fund. The Company funds the SEF from the 1.74 cents per kWh transmission and distribution rate at .01 cents per kWh on all power sold for all customers beginning on January 1, 1999 and ending on December 31, 2004. The SEF has a seven-member Board of Directors nominated by the Joint Petitioners and approved by the Commission. The Board of Directors designated an administrator to manage the fund on a day-to-day basis. The Commission reviewed and approved the SEF's by-laws and the fund is required to have an annual audit and to submit semi-annual reports to the Commission. The purpose of the fund, as noted in PPL Electric's *Settlement* Agreement, is ". . . to promote the development and use of renewable energy and clean energy technologies, energy conservation and efficiency which promote clean energy."

Q. What is the mission of the Sustainable Energy Fund?

A. The mission of the SEF of Central and Eastern Pennsylvania is as follows:

> "Our mission is to promote, research and invest in clean and renewable energy technologies, energy conservation, *energy efficiency* and sustainable energy enterprises that provide opportunities and benefits for PPL's ratepayers."

Q. How much has been provided by customers to the SEF between 1999 and 2003?

A. As noted above, all customers fund the SEF through a charge of .01 cents per kWh on all power sold, which has totaled just over $16 million from 1999 through 2003. The amount of funding by calendar year appears below.

1999	**2000**	**2001**	**2002**	**2003**	**Total**
$3,038,981	$3,233,012	$3,326,903	3,357,900	$3,379,544	$16,336,340

Q. How much funding has the SEF committed for fiscal years 2000 through 2003?

A. The SEF has committed a total of $7,186,156 in program-related investments *and grants* through June 30, 2003. The breakout between the two elements is as follows: $6,530,000 (90.9 percent) in program investments and $656,156 (9.1 percent) in grants. The breakout by fiscal year appears below.

Fiscal Year	**Program Investments**	**Grants**	**Total**
2001	$2,225,000	$165,000	$2,390,000
2002	$1,300,000	$269,922	$1,569,922
2003	$3,005,000	$221,234	$3,226,234
Total	$6,530,000	$656,156	$7,186,156

Q. What have been the areas of focus for the SEF?

A. Specific areas of focus include:

- Wind development in Pennsylvania
- Green buildings
- Emerging electric technologies
- Community economic development
- Sustainable energy education

See Exhibit TRD3 for a summary provided by the SEF of its major projects and activities.

Q. Are there other areas of interest the SEF has indicated it may pursue in the future?

A. In addition to continuing the activities listed above, the SEF has indicated that it sees benefit in working in areas such as fuel cells, residential programs (e.g., photovoltaic rebates) and agricultural bio-digester initiatives to better handle manure, while providing power production.

Q. What is PPL Electric's recommendation regarding continued funding for the Sustainable Energy Fund beyond December 31, 2004?

A. If approved by the Commission, PPL Electric proposes to continue funding for the SEF at the current level of .01 cents per kWh hour for all customers for period to end no later than December 31, 2009. This maximum termination date coincides with the end of the transition period for PPL Electric and the subsequent removal of the generation rate caps. With Commission approval, the Company would use existing procedures to collect and disburse funds to the SEF beginning January 1, 2005.

Q. Does PPL Electric believe a charge of .01 cents per kWh of all power sold results in an appropriate level of annual funding for the SEF?

A. From the Company's perspective, continuing the current funding mechanism of a charge of .01 cents per kWh is appropriate for several reasons. First, the SEF has effectively managed its funding and has a strong balance sheet. For the reporting period ending June 30, 2003, the SEF had unrestricted net assets of $12,203,454. Second, state government also plays a key role in supporting environmental initiatives. As evidenced by Governor Rendell's budget proposal, quality of life and environmental issues are significant components. In other words, it is likely that state government may provide funding or other incentives to address environmental issues. Third, PPL Electric also is attempting to balance the needs of supporting important public policy objectives (i.e., protecting and improving the environment) while minimizing the cost impact on all customers. Continuing the current funding mechanism for the SEF appears to strike a proper balance. Fourth, over the years there has been a modest but steady increase in kWh usage by all customers. This increase in kWh usage translates into a slight increase in funding for the SEF. *Finally, the whole arena of renewable energy technologies and* sustainable energy enterprises is still a nascent and evolving industry in Pennsylvania. The various SEFs across the state need more time to expand their capabilities and to firmly establish their long-term viability. Given the important role of state government in supporting environmental initiatives, PPL Electric believes that funding the SEF of Central and Eastern Pennsylvania at .01 cents per kWh is the appropriate level of support from all customers.

Q. Are there any circumstances under which PPL Electric would propose terminating the funding for the SEF?

A. Although unlikely, the Company would consider asking the Commission for permission to stop funding the SEF if certain developments occurred. Some examples include the following:

- If, through ineffective administration, the SEF lost credibility with the Commission and other key external stakeholders and partners.

- If the SEF started to fund and support projects that were inconsistent with the original purpose of the fund as approved in the 1998 Settlement Agreement.
- If the SEF staff or Board of Directors knowingly violated the Commission-approved by-laws for the fund.
- If the SEF staff or Board of Directors fraudulently misused customer funding.

Q. Does this conclude your direct testimony?
A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

PPL Electric Utilities Corporation

Statement No. 8

Direct Testimony of John J. Spanos

Direct Testimony of John J. Spanos

Q. Please state your name and address.

A. John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. With what firm are you associated?

A. I am associated with the firm of Gannett Fleming, Inc.

Q How long have you been associated with Gannett Fleming, Inc.?

A. I have been associated with the firm since college graduation in June 1986.

Q. What is your position in the firm?

A. I am a Vice President.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College of Pennsylvania.

Q. Are you a member of any professional societies?

A. Yes. I am a member of the Society of Depreciation Professionals and the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Have you taken the certification examination for depreciation professionals?

A. Yes, I passed the certification examination of the Society of Depreciation Professionals in September 1997 and was recertified in August 2003.

Q. Will you outline your experience in the field of depreciation?

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 to December 1995, I took part in the preparation of numerous depreciation and original cost studies for utility companies in various industries. Depreciation studies of telephone companies were performed for United Telephone of Pennsylvania, United Telephone of New Jersey and Anchorage Telephone Utility. My work in the railroad industry included depreciation studies for Union Pacific Railroad, Burlington Northern Railroad and Wisconsin Central Transportation Corporation.

Assignments in the electric industry included depreciation studies for Chugach Electric Association, The Cincinnati Gas and Electric Company, The Union Light, Heat & Power Company, Northwest Territories Power Corporation and the City of Calgary - Electric System. Pipeline industry assignments included studies for TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

My work for the gas industry included depreciation studies for Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, The Cincinnati Gas and Electric Company, The Union Light, Heat & Power Company, Lawrenceburg Gas Company and Penn Fuel Gas, Inc. Assignments in the water industry included depreciation studies for Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

My participation in each of the above studies included assembly and analysis of historical and simulated data, field reviews, the development of preliminary estimates of service life and net salvage, calculations of annual depreciation, and the preparation of reports for submission to state or provincial public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E., the President of Gannett Fleming Valuation and Rate Consultants, Inc.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July 1999, I was promoted to the position of Manager, Depreciation and Valuation Studies. In December 2000, I was promoted to my current position as Vice President of Gannett Fleming Valuation and Rate Consultants, Inc. I am responsible for all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory body.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Hampton Water Works Company, Omaha Public Power District, Enbridge Pipe Line Company, Inc., Columbia Gas of Virginia, Inc., Virginia Natural Gas Company, CenterPoint Energy – Arkla, National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions, The City of Bethlehem - Bureau of Water, The City of Coatesville Authority, The City of Lancaster - Bureau of Water, Enbridge Consumers Gas Company, Peoples Energy Corporation, The York Water Company, Public Service Company of Colorado, Reliant Energy-HLP, Massachusetts-American Water Company, St. Louis County Water Company, Missouri-American Water Company, Chugach Electric Association, Alliant Energy, Oklahoma Gas and Electric Company, Nevada Power Company, Dominion Virginia Power, NUI-Virginia Gas Companies, PSI Energy, NUI - Elizabethtown Gas Company, Cinergy Corporation – CG&E, Cinergy Corporation – ULH&P, Columbia Gas of Kentucky, Idaho Power Company, El Paso Electric Company, Centennial Pipeline Company, NSTAR – Boston Edison Company, South Jersey Gas Company, EPCOR Distribution, Inc. and B. C. Gas Utility, Ltd. My additional duties include determining final life and salvage estimates, conducting field reviews and presenting recommended depreciation rates to management for their consideration.

Q. What is the extent of your formal instruction with respect to utility plant depreciation?

A. I have completed the "Techniques of Life Analysis", "Techniques of Salvage and Depreciation Analysis", "Forecasting Life and Salvage", "Modeling and Life Analysis Using Simulation" and "Managing a Depreciation Study" programs conducted by Depreciation Programs, Inc. Also, I have completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. *Have you previously testified on public utility ratemaking matters?*

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission, the Commonwealth of Kentucky Public Service Commission, the Public Utilities Commission of Ohio, the Public Utility Commission of Nevada, Indiana Utility Regulatory Commission, the Public Utilities Board of New Jersey, Missouri Public Service Commission, Energy Utility Board of Alberta, the Louisiana Public Service Commission and the Massachusetts Department of Telecommunications and Energy.

Q. What is the purpose of your testimony?

A. My testimony is in support of the depreciation study conducted under my direction and supervision for the utility plant of PPL Electric Utilities Corporation.

Q. Have you prepared an exhibit presenting the results of your study?

A. Yes. Exhibit JJS1 presents the results of the depreciation study as of December 31, 2004. In addition, I am responsible for the responses to the Filing

Requirements – Depreciation V-A-2, V-B-1, V-B-2, V-C-1, V-D-1, V-D-2 and V-E-1.

Q. Please describe Exhibit JJS1.

A. Exhibit JJS1 titled "Depreciation Study Related to Electric Plant at December 31, 2004," includes the results of the depreciation study as related to the estimated original cost at December 31, 2004. The report also includes explanatory text, statistics related to the estimation of service life, and the detailed depreciation calculations.

Q. What was the purpose of your depreciation study?

A. The purpose of the depreciation study was to estimate the annual depreciation accruals related to utility plant in service for ratemaking purposes at December 31, 2004.

Q. Is the Company's claim for annual depreciation in the current proceeding based on the same methods of depreciation as were used in its most recent electric rate proceeding in Docket No. R-00943271?

A. Yes, it is. For most plant accounts, the current claim for annual depreciation is based on the straight line remaining life method of depreciation. For Accounts 368, 370, 391, 393, 395, 397 and 398, the claim is based on the straight line remaining life method of amortization. The annual amortization is based on amortization accounting which distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account.

Q. What group procedure is being used in this proceeding for depreciable accounts?

A. The average service life procedure is used in the current proceeding for all depreciable accounts and installation years. The average service life procedure also was used in this same manner in the Company's last rate proceeding.

Q. Has a service life study of the Company's electric utility property been performed?

A. Yes. A service life study has been performed through 2002 as a part of this filing. The service life study is the basis for the service lives I used to calculate annual accruals.

Q. Briefly outline the procedure used in performing the service life study.

A. The service life study consisted of assembling and compiling historical data from the records related to the electric utility plant of the Company; statistically analyzing such data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning Company practices and plans as they relate to plant operations; and interpreting the above data to form judgments of service life characteristics.

Iowa type survivor curves were used to describe the estimated survivor characteristics of the mass property groups. Individual service lives were used for major individual units of plant, such as large service centers and office buildings within Account 390.2. The life span concept was recognized by coordinating the lives of associated plant installed in subsequent years with the probable retirement date defined by the life estimated for the major unit.

Q. What statistical data were employed in the historical analyses performed for the purpose of estimating service life characteristics?

A. The data consisted of the entries made to record retirements and other transactions related to the electric plant through 2002. These entries were classified by depreciable group, type of transaction, the year in which the transaction took place, and the year in which the plant was installed. Types of transactions included in the data were plant additions, retirements, transfers, and balances. In the presentation of service life statistics, only the significant exposure points that were utilized in determining survivor curves were plotted. This process is utilized to show my judgment in service life determinations.

Q. What was the source of these data?

A. They were assembled from Company records related to its utility plant in service.

Q. Were the methods used in the service life study the same as those used in other depreciation studies for electric utility plant presented before this Commission?

A. Yes. The methods are the same ones that have been presented previously for PPL Electric Utilities Corporation and for other electric companies before the

Pennsylvania Public Utility Commission and that have been accepted by the Commission in its past orders concerning electric utilities.

Q. What approach did you use to estimate the lives of significant structures such as office buildings and service centers?

A. I used the life span technique to estimate the lives of significant structures. In this technique, the survivor characteristics of the structures are described by the use of interim survivor curves and estimated probable retirement dates. The interim survivor curve describes the rate of retirement related to the replacement of elements of the structure such as plumbing, heating, doors, windows, roofs, etc. that occur during the life of the facility. The probable retirement date provides the rate of final retirement for each year of installation for the structure by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of the several years of installation inasmuch as concurrent retirement of all years of installation will occur when the structure is retired.

Q. Has your firm used this approach in other proceedings before this Commission?

A. Yes, we have used the life span technique on many occasions before the Pennsylvania Public Utility Commission.

Q. What are the bases for the probable retirement years that you have estimated for *each structure?*

A. The bases for the estimates of probable retirement years are life spans for each structure that are based on judgment and incorporate consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other electric utilities for similar structures. Most of the life spans result in probable retirement years that are many years in the future. As a result, the retirement of these structures is not yet subject to specific management plans. Such plans would be premature. At the appropriate time, analysis of the economics of rehabilitation and continued use or retirement of the structure will be performed and the results incorporated in the estimation of the structure's life span.

Q. Are the factors considered in your estimates of service life presented in Exhibit JJS1?

A. Yes. A discussion of the factors considered in the estimation of service lives is presented by account on pages II-3 through II-26 of Exhibit JJS1.

Q. Please outline the contents of Exhibit JJS1.

A. Exhibit JJS1 is presented in three parts. Part I, Executive Summary, sets forth the scope and basis of study. Part II, Methods Used in Study, includes the estimation of survivor curves, and the calculation of annual depreciation and amortization.

Part III, Results of Study, presents a description of the results, summaries of the depreciation calculations, graphs and tables which relate to the service life study, and the detailed depreciation calculations.

The table on pages III-4 and III-5, presents the estimated survivor curve, the original cost at December 31, 2004, and the book reserve and calculated annual depreciation for each account or subaccount of Utility Plant. The section beginning on page III-7 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page III-97 presents the depreciation calculations related to original cost. The tabulations on pages III-98 through III-188 present the calculation of annual depreciation by vintage by account for each depreciable group of utility plant.

Q. Please use an example to illustrate the manner in which the study is presented in Exhibit JJS1.

A. I will use Account 365, Overhead Conductors and Devices, as my example, inasmuch as it is one of the larger depreciable groups and represents 12 percent of the original cost of depreciable utility plant as of December 31, 2004.

The retirement rate method was used to analyze the survivor characteristics of this group. The life table for the 1912-2002 experience band is presented on pages III-61 through III-63 of Exhibit JJS1. The life table, or original survivor curve, is plotted along with the estimated smooth survivor curve, the 41-R1.5, on page III-60.

The calculation at December 31, 2004, is presented on pages III-142 through III-144 of Exhibit JJS1 and is based in part on the bringforward of the book reserve. The tabulation in Exhibit JJS1 sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. The totals are brought forward to the table on page III-4 in Exhibit JJS1.

Q. Does this complete your testimony at this time?

A. Yes, it does.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-00049255

PPL Electric Utilities Corporation

Statement No. 9

Direct Testimony of Paul R. Moul

PPL ELECTRIC UTILITIES CORPORATION

Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning
Rate of Return

PPL Electric Utilities Corporation

Direct Testimony of Paul R. Moul
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DIRECT TESTIMONY OF PAUL R. MOUL

INTRODUCTION AND SUMMARY OF RECOMMENDATION

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

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant of the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Appendix A that follows my direct testimony.

Q. What is the purpose of your testimony?

A. My testimony presents evidence, analysis and a recommendation concerning the appropriate cost of equity and overall fair rate of return that the Pennsylvania Public Utility Commission ("PUC" or the "Commission") should allow PPL Electric Utilities Corporation ("PPL Electric" or the "Company") an opportunity to earn on its rate base devoted to public service. My analysis and recommendation are supported by the detailed financial data set forth in Exhibit PRM-1, which is a multi-page document that is divided into fifteen (15) schedules. Additional evidence, in the form of appendices, follows my direct testimony. The items covered in these appendices deal with the technical aspects of my testimony.

Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return for the Company?

A. Based upon my independent analysis, my conclusion is that the Company should be afforded an opportunity to earn a rate of return on common equity of 11.50%, and an overall rate of return of 8.80%. I reached this determination based upon the range of the results of the models/methods I used to measure the cost of equity. As my testimony will demonstrate, an 11.50% cost of equity is warranted in this case for the Company and is at the upper end of my range in recognition of: the continuing uncertainty surrounding the restructuring of the electric industry, the Company's credit quality that is presently viewed negatively, narrowly defined sources of cash flow, accelerating levels of capital expenditures, and in recognition of the exemplary performance of the Company's management in dealing with these challenges.

My overall rate of return recommendation is determined by using the weighted average cost of capital. This approach provides a means to apportion the return to each class of investor. The calculation of the weighted average cost of capital requires the selection of appropriate capital structure ratios and a determination of the cost rate for each capital component. The resulting overall fair rate of return, when applied to the Company's rate base, will provide a compensatory level of return for the use of capital and provide the Company with the ability to attract capital.

Q. What background information concerning the Company have you considered as part of your testimony?

A. The Company is an electric utility that provides service to approximately 1,300,000 customers in twenty-nine central and eastern Pennsylvania counties. The Company provides distribution services to all its customers and electric sales as the provider of last resort ("POLR") to all but about 4,500 customers. The Company's energy deliveries are represented by approximately 36% from residential customers, 35% from commercial customers, 28% from industrial customers, and 1% from street lighting, public authorities and railroads. The Company obtains the energy to meet its POLR obligations through a Commission approved contract with PPL EnergyPlus that extends through 2009. PPL Electric is a wholly-owned subsidiary of PPL Corporation. The common stock of PPL Corporation is traded on the New York Stock Exchange. PPL Corporation is a component of the Standard & Poor's Public Utility Index and the S&P 500 Composite Index.

Q. How have you determined the cost of equity for the Company?

A. My recommended cost of equity is established using capital market and financial data relied upon by investors when assessing the relative risk, and hence cost of equity, for an electric utility, such as PPL Electric. In analyzing the Company's cost of equity, I have relied on four, well-recognized measures: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach. By considering the results of a variety of approaches, my analysis is consistent with the well-recognized principles for determining a fair rate of return. I have measured the cost of equity for the Company using data from a variety of sources. It is necessary to do so because it is difficult to establish an appropriate group of proxy companies in the electric delivery business during this period of transition. I therefore have relied on include market data from both a proxy group of nine electric companies that are identified on page 2 of Schedule 3, and an additional proxy group of eight gas distribution companies that are identified on page 2 of Schedule 4. I will refer to my proxy group of nine electric companies as the "Electric Group" and the group of eight gas companies as the "Gas Group" throughout my testimony.

Rather than rely upon the market-determined cost of equity for an individual company, I have employed the stock market prices for the Electric Group and the Gas

Group. By employing group averages, rather than individual company analysis, I have sought to minimize the effect of any anomalies in the market data for an individual company. Such anomalies are very much present in the electric utility industry as it exists today.

Q. Why have you given consideration to a second group of utilities in conducting your analysis of the Company's cost of equity?

A. Finding a reasonable proxy group of electric delivery companies in the current business and regulatory environment is problematic. As such, I have also considered the market evidence for the Gas Group noted above. Like the Electric Group, the companies in the Gas Group are subject to traditional cost of service regulation. That is to say, cost of service regulation dominates the revenues and income of the Gas Group. Moreover, the Gas Group has a long history of providing regulated delivery service, and many of the fundamentals the affect the delivery of natural gas at regulated prices parallel those for the delivery of electric energy. Moreover, the regulation of natural gas distribution has a very long history -- approaching or exceeding a century of regulation. Hence, investors fully comprehend the regulatory framework associated with the gas distribution business and are not affected by the uncertainty associated with transition issues for electric utilities. This makes the market evidence of the Gas Group a meaningful contributor to assessing the risk and required return for the electric delivery business.

Q. Please summarize the basis for your cost of equity recommendation in this proceeding.

A. My recommendation is derived from the results of the four methods/models previously identified. In general, the use of more than one approach provides a superior foundation to arrive at the cost of equity. At any point in time, individual methods can provide an incomplete measure of the cost of equity depending upon extraneous factors which may influence market sentiment. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches.

	Electric Group	Gas Group
DCF	10.69%	11.22%
Risk Premium	11.75%	11.75%
CAPM	10.71%	11.22%
Comparable Earnings	14.25%	14.25%

The average of these measures of the cost of equity is 11.85% for the Electric Group and 12.11% for the Gas Group. The median equity return is 11.23% for the Electric Group and 11.49% for the Gas Group. From the results indicated above, I recommend that the Company's cost of equity be set within the range of 11.00% to 11.75%. In recognition of the uncertainties that are associated with the end of the transition phase of restructuring, the negative outlook for the Company's credit quality, its more narrowly defined source of cash flow, accelerating levels of capital expenditures, and in recognition of the exemplary performance of the Company's management, as described in the pre-filed direct testimony of the Company's President, Mr. John F. Sipics, the rate of return on common equity should be set within the upper half of the range, or is this case 11.50%

Q. In your opinion, what factors should the Commission consider when setting the Company's cost of capital in this proceeding?

A. The Commission should consider the ratesetting principles that I have set forth in Appendix B. In this regard, the Commission's rate of return allowance must be set to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, support reasonable credit quality, and allow the Company to raise capital on reasonable terms.

ELECTRIC UTILITY RISK FACTORS

Q. Please identify some of the factors that make the electric utility industry generally different today than it was in the past.

A. Today, electric utilities are faced generally with meaningful changes in the fundamentals that affect their operations, while cost of service pricing continues to dominate much of their business profile. On the national level, the passage of the National Energy Policy Act (EPACT) and the issuance of FERC Order Nos. 888 and 889 and Order No. 2000 initiated sweeping changes that fundamentally altered the structure of the electric utility business. EPACT removes certain impediments to the construction of non-utility generators (NUGs) by utility affiliates and by independent developers. Order Nos. 888 and 889 have provided these generators, as well as other utilities, with the ability to sell their energy directly to wholesale customers, as well as to end-use customers in states with retail competition. Order No. 2000 encourages the formation of Regional Transmission Organizations (RTO). Under the rules of Order

No. 2000, RTOs will be formed as independent entities that offer non-discriminatory transmission service. Uncertainties that bear upon the risk of electric utilities generally include the final structure of the RTOs and implementation of the proposed Standard Market Design (SMD) that has been developed by the FERC. Also, technological advances in microturbines and potential commercialization of fuel cells raise risk issues for the transmission and distribution (T&D) segment of the electric utility business. As the risk of potential stranded costs arises due to these technological advances, investors perceive more risk.

Q. What changes have occurred in Pennsylvania as a result of a move to more competitive markets for electricity?

A. On January 2, 2000, customer choice was fully available in Pennsylvania for electricity. From that point forward, PPL Electric's responsibility became primarily the provision of delivery service at regulated prices, while it also retained the responsibility for POLR service to customers that do not elect competitive energy suppliers. The restructuring of the electric business in Pennsylvania has been underway for several years. The rates being considered in this case relate solely to the unbundled delivery service.

Q. What are the primary risks factors facing the electric delivery business?

A. Aside from their traditional responsibility to maintain reliability and comply with the mandates of PJM, a different set of risks are now evolving in a new era for the electric delivery business in Pennsylvania. The risk of self-generation will continue to be a concern, and could have an increasing influence on the business of electric delivery utilities. In addition, utilities retain the obligation to provide reliable delivery service and must continue to invest in their rate base to fulfill that obligation. There are other challenges related to siting and permitting, giving rise to additional costs and delays that could impact reliability. Regulatory risks will continue to evolve in the newly restructured environment. These include the overall framework of ratesetting, cost allocation and rate design issues, and the level of return that will be allowed. PJM planning requires construction of facilities, which provide an impetus to build more transmission facilities, along with construction for distribution facilities that are necessary to maintain, upgrade and expand the network to serve customers. Regulatory reviews will undoubtedly arise after completion of such projects.

The financial structure of the electric business is uncertain due to the final structure of the Company's POLR obligation and the loss of diversification that formerly existed within an integrated system that has resulted in a more narrowly defined source of revenues. With a meaningful proportion of its load provided by industrial customers, the Company has no ability to offset declines in usage and revenues by industrial customers with off system sales, since it no longer has generation to provide additional revenue. For the Company with relatively high industrial load, the loss of a diversified revenue stream is potentially problematic. Counter-party risk has also developed into a major risk factor. These are examples of broader risks associated with the developing retail markets. With the limited participation of customers in the competitive retail markets, investors are concerned about the success of the new market. Together with the increased need for transmission and distribution facilities, investors are concerned about cost recovery issues where additional investment is either mandated or required. Finally, a delivery-only electric company lacks the risk reducing benefits of economies of scope, control over the planning and operation of both the generation and delivery of electricity, and more diversified sources of revenue. These attributes that are missing from a delivery-only electric company, which elevates its remaining risks. Further, regulatory risk is heightened for a delivery-only electric company due to its single line of business.

Q. Are there other risks facing PPL Electric?

A. Yes. Energy deliveries to non-residential customers which represent 64% of the Company's energy deliveries are usually thought to be of higher risk than to residential customers. Success in this segment of the Company's market is subject to (i) the business cycle, (ii) the price of alternative energy sources, and (iii) pressures from alternative providers. Moreover, external factors can also influence deliveries to these customers, which face competitive pressure on their own operations from other facilities outside the utility's service territory.

Q. Please indicate how the Company's risk profile is affected by its construction program.

A. The Company is faced with the requirement to undertake investment to maintain and upgrade existing facilities in its service territory and to meet growth. The Company is engaged in a continuing capital expenditure program necessary to fulfill the needs of its customers and to comply with various regulations. For the future, the Company expects its construction expenditures to be:

	Capital Expenditures
2004	$166,000,000
2005	183,000,000
2006	203,000,000
2007	217,000,000
Total	$769,000,000

Over the next four years, these capital expenditures will represent an approximate 30% ($769,000,000 ÷ $2,584,000,000) increase in net utility plant from the levels at December 31, 2003. As shown by the construction expenditures for the next several years, the Company is entering a period of increasing capital requirements. A reasonable opportunity to experience a fair rate of return represents the key to a financial profile that will provide the Company with the ability to raise capital in all market conditions to meet its needs, and to satisfy investor requirements in an evolving industry.

Q. How should the Commission respond to the evolving business environment facing the Company?

A. In the situation where additional capital is required, as shown by the projected construction expenditures indicated above, the regulatory process must establish a return on equity that provides a reasonable opportunity for the Company to actually achieve its cost of capital. Where substantial ongoing capital investment is required to meet the high quality of service that customers demand, supportive regulation is absolutely essential.

FUNDAMENTAL RISK ANALYSIS

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for a determination of a utility's cost of equity?

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors, which bear upon the Company's risk, have already been discussed. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and their required returns are described in Appendix C. For this purpose, I have compared the Company to the S&P Public Utilities, an industry-wide proxy consisting of various public utility endeavors, and to the Electric Group and the Gas Group.

Q. What are the components of the S&P Public Utilities?

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power companies and natural gas companies. These companies are identified on page 3 of Schedule 4. I have used this group as a broad-based measure of public utility endeavors.

Q. What criteria have you employed to assemble your Electric Group?

A. The Electric Group companies have the following common characteristics: (i) they are listed in the "Electric Utility (East)" section of <u>The Value Line Investment Survey</u>, (ii) their stock is traded on the New York Stock Exchange, (iii) they operate in the Northeastern and Southeastern regions of the U.S., (iv) they are not currently the target of a publicly-announced merger or acquisition, and (v) they do not have a significant amount of electric generation that is unregulated. It would be inappropriate to include a company that is a target of a takeover in a proxy group because the stock price of that company usually does not reflect its underlying fundamentals.

Q. What criteria have you employed to assemble your Gas Group?

A. The Gas Group I have employed in this case includes companies that are engaged in similar business lines and have marketable securities. The Gas Group companies have the following common characteristics: (i) they are listed in the "Natural Gas Distribution" section of The Value Line Investment Survey ("Value Line"), (ii) their stock is traded on the New York Stock Exchange, (iii) they have operations in the Northeastern and Southeastern regions of the U.S., and (iv) they are not currently the target of a publicly-announced merger or acquisition.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So while a company's credit quality risk is shown directly by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus compensation to recognize the higher risk of an equity investment compared to debt.

Q. How do the bond ratings compare for the Company, the Electric Group, the Gas Group and the S&P Public Utilities?

A. Presently, the corporate credit rating for PPL Electric is A- from S&P and Baa2 from Moody's. The Company's credit rating from S&P is on credit watch with a negative outlook. The Electric Group's average credit quality rating is BBB+ from S&P and

A3 from Moody's. The average rating for the Gas Group is an A from S&P and an A2 from Moody's. For the S&P Public Utilities, the average composite rating is BBB by S&P and Baa2 by Moody's. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. What factors influence the bond ratings assigned by the credit rating agencies?

A. The credit rating agencies consider various qualitative and quantitative factors in assigning grades of creditworthiness. On June 18, 1999, S&P modified its benchmark criteria with a focus on the relative business risk of a firm regardless of its industry-type. These benchmarks replaced former criteria that were directed toward specific types of utilities. Now, each electric utility company will be measured against a uniform set of financial benchmarks applicable to all firms that are assigned to a specific business profile. S&P has indicated that no rating changes should be expected from the new financial targets because they were developed by integrating prior financial benchmarks and historical industrial medians. The financial benchmarks for a utility with a "3" business profile, which is the profile assigned to PPL Electric by S&P, includes:

Rating	Pre-Tax Interest Coverage	Debt Leverage	Funds from Operations Interest Coverage	Funds from Operations to Total Debt
AA	4.0-3.4x	42.0-47.5%	4.5-3.9x	31.5-26.0%
A	3.4-2.8	47.5-53.0	3.9-3.1	26.0-20.0
BBB	2.8-1.8	53.0-61.0	3.1-2.1	20.0-14.0
BB	1.8-1.1	61.0-67.0	2.1-1.3	14.0-9.5
B	1.1-0.3	67.0-74.0	1.3-0.5	9.5-4.0

As I will discuss later, the debt ratio proposed by the Company in this case would fit into the A rating category, which, is necessary to sustain its bond rating.

Q. How do the financial data compare for PPL Electric, the Electric Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3, 4, and 5. This analysis covers the years 1998 through 2002. The important categories of relative risk may be summarized as follows:

<u>Size</u>. In terms of capitalization, the Company is smaller than the average size of the Electric Group, but fairly similar to the average size of the Gas Group. The average size of the S&P Public Utilities is many times larger than the Company, the Electric Group, and the Gas Group. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity. This is the case for the Electric Group and the Gas Group.

<u>Market Ratios</u>. Market-based financial ratios, such as earnings/price ratios and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher return on equity for companies that exhibit greater risk as compensation for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings; a high earnings/price ratio is thus indicative of greater risk.[1]

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[1] For example, two otherwise similarly situated firms each reporting $1.00 earnings per share would have different market prices at varying levels of risk, i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value.

There are no market ratios available for the Company. The average earnings/price ratio for the Electric Group was less than the Gas Group and the S&P Public Utilities, which were fairly similar. The average dividend yield was similar for the Electric Group and the Gas Group, while the dividend yield for the S&P Public Utilities was lower. On average, the historical market-to-book ratios were similar for the Gas Group and S&P Public Utilities, while it was lower for the Electric Group. I will subsequently discuss the cost of equity implications of market-to-book ratios.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has low financial risk, while a firm with a low common equity ratio has high financial risk. The five-year average common equity ratios, based on permanent capital, were 40.2% for the Company, 44.1% for the Electric Group, 48.0% for the Gas Group, and 39.9% for the S&P Public Utilities. From a financial risk perspective, the S&P Public Utilities shows the highest financial risk, followed by PPL Electric, the Electric Group, and finally the Gas Group, which has the lowest financial risk. This issue is being addressed in this case with a proposed capital structure in that contains less debt and is compatible with the A bond rating.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relative levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficient of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.593 (9.6% ÷ 16.2%) for the Company, 0.301 (2.5% ÷ 8.3%) for the Electric Group, 0.087 (1.0% ÷ 11.5%) for the Gas Group, and 0.250 (2.7% ÷ 10.8%) for the S&P Public Utilities. The earnings variability was highest for PPL Electric, followed by the Electric Group, the S&P Public Utilities, and the Gas Group, which had the lowest earnings variability. This comparison shows that the Company's risk is above that of the Electric Group and the Gas Group.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation and taxes other than income)[2]. The five-year average operating ratios were 82.7% for the Company, 86.5% for the Electric Group, and 86.6% for the Gas Group, and 84.3% for the S&P Public Utilities. The Company's lower operating ratio on average can be traced to the relatively high returns in the early years of the analysis.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense and preferred stock dividends) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average pre-tax interest coverage (excluding AFUDC) was 2.90 times for the Company, 2.71 times for the Electric Group, and 3.19 times for the Gas Group, and 2.74 times for the S&P Public Utilities. From these comparisons, the Gas Group possessed the highest level

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2 The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

of creditor protection, followed by the Company, the S&P Public Utilities, and finally the Electric Group.

Quality of Earnings. Measures of earnings quality are usually revealed by the percentage of Allowance for Funds Used During Construction ("AFUDC") related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for the Company, the Electric Group, the Gas Group, and the S&P Utilities in recent years.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 181.0% for the Company, 152.7% for the Electric Group, 73.7% for the Gas Group, and 102.0% for the S&P Public Utilities. Cash flow which is less than construction requirements indicates higher risk for the Gas Group compared to the Company, the Electric Group and the S&P Public Utilities.

Betas. The financial data I have been discussing relate primarily to company-specific risks. Market risk for firms with traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities. Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the average betas of .66 for the Electric Group (see page 2 of Schedule 3), .69 for the Gas Group (see page 2 of Schedule 4), and .82

for the S&P Public Utilities (see page 4 of Schedule 5). Keeping in mind that the utility industry has changed significantly during the past several years, the systematic risk percentage was 80% (.66 ÷ .82) for the Electric Group and 84% (.69 ÷ .82) for the Gas Group using the S&P Public Utilities' average beta as a benchmark.

Q. Please summarize your risk evaluation of the Company, the Electric Group, and the Gas Group.

A. Historically, the risk of PPL Electric parallels that of the Electric Group in certain respects, although the Company is smaller, it has much more variable earned returns, and it had historically a lower common equity ratio. Although the Company had relatively high IGF to construction historically, increases in construction expenditures prospectively will exceed IGF. Indeed, going forward, filing requirement III-F-2 shows that the IGF to construction will be 105% in 2004, 73% in 2005, 68% in 2006, and 65% in 2007. These projections show deterioration in the Company's IGF to construction. In many respects, the Gas Group provides meaningful evidence of the Company's cost of equity. Characteristics of the Gas Group that are similar to the Company include: the business profile of "3", a common equity ratio that prospectively will be close to the Gas Group an operating ratio that for the Company has climbed to the level of the Gas Group, and an IGF percentage that for the Company is forecast to decline to the levels of the Gas Group. On balance the Gas Group is equally relevant to the measurement of the Company's cost of equity.

CAPITAL STRUCTURE RATIOS

Q. Please explain the selection of capital structure ratios for PPL Electric in this case.

A. In the situation where the operating public utility raises its own long-term debt and preferred stock directly in the capital markets, as is the case for PPL Electric, it is proper to employ the capital structure ratios and senior capital cost rates of the regulated public utility for rate of return purposes. Furthermore, consistency requires that the embedded cost rate of the Company's senior securities also be employed. This procedure is consistent with the ratesetting procedures used by the Commission in numerous prior rate cases for PPL Electric.

Q. Does Schedule 6 provide the capitalization and capital structure ratios you have considered?

A. Yes. Schedule 6 presents PPL Electric's capitalization and related capital structure at December 31, 2003, the end of the historic test year. Also shown on Schedule 6 is the PPL Electric's capital structure estimated at December 31, 2004, the end of the future test year. During the future test year, the changes in the Company's capital structure are projected to be: (i) the maturity of \$24.767 million of 6.875% First Mortgage Bonds, (ii) the early redemption of \$5.805 million of 7.30% First Mortgage Bonds, (iii) the planned redemption of \$50 million of 6.50% and \$50 million of 6.55% First Mortgage Bonds, and (iv) the Company's projection of retained earnings at December 31, 2004. I have also adjusted the Company's capital structure to recognize the ratesetting treatment of the call premiums on the early redemption of high cost long-term debt and preferred stock that has been redeemed. The debt redemptions in the future test year are intended to strengthen the Company's common equity ratio to support its bond ratings.

Q. Please describe these adjustments.

A. I have adjusted the principal amounts of long-term debt and preferred stock to exclude the amounts used to finance premiums on the early redemption of long-term debt and preferred and preference stock. To do otherwise would deny PPL Electric the full return on the premiums paid to redeem this high cost capital since additional amounts of capital were issued to pay the call premiums. The amounts issued to finance the call premiums do not increase the Company's rate base. That is to say, no additional rate base was created through additional debt and preferred stock necessary to finance this transaction, and therefore an adjustment is required to provide the return necessary to service this additional capital. Hence, PPL Electric's long-term debt and preferred stock amounts must be adjusted for this disparity in order that the return necessary to service the capitalization is produced from rate base investment times the overall rate of return.

This adjustment is equitable since customers receive the cost savings resulting from these refinancing in the form of a lower overall rate of return, and PPL Electric recovers all costs incurred in providing these benefits to the customers. To accomplish these savings, the Company paid the debt and preferred holders a premium for surrendering their securities prior to maturity. These premiums represented an investment made by PPL Electric to reduce its overall cost of capital. Since the reduced interest costs and preferred stock dividends are reflected in the lower cost of capital to ratepayers, it is appropriate that the Company recover the costs incurred to produce these savings. This includes both a return of and return on the unamortized premiums. Adjusting the principal amounts in the capital structure provides a return on the premium as a part of the embedded cost rates of capital.

Q. Are there additional adjustments necessary to reflect the call of high cost preferred and preference stock?

A. Yes. Unlike the situation where the Company recorded the call premiums on the long-term debt as deferred debits for future recovery in rates, no similar accounting was available to the Company for the call premiums associated with the early redemption of the preferred and preference stock. Instead, those amounts were charged directly to retained earnings. Also, the Company financed the call premium with the additional sale of preferred stock. The Commission has encouraged utilities to refinance high-cost capital and has stated that a utility will not be penalized for undertaking a refinancing. Hence, it is necessary to restore the Company's capital structure to the condition which existed prior to the refinancing of the high cost preferred and preference stock. To accomplish this, it is necessary to reduce the preferred stock outstanding by the amount of the call premium and to remove a similar amount for the charge to retained earnings for the call premiums. These adjustments maintain the aggregate amount of total capitalization for the Company. All of my adjustments to the Company's capital structure for call premiums comply with adjustments routinely approved by the Commission and were adopted by the Commission is the Company's last rate case decision.

Q. What capital structure ratios do you recommend be adopted for rate of return purposes in this proceeding?

A. Since ratemaking is prospective, the rate of return should reflect known changes that will occur during the course of the future test year, at a minimum, and should consider conditions that will exist during the period of time the proposed rates will be effective.

I will adopt the Company's forecast capital structure ratios at December 31, 2004 of 51.30% long-term debt, 1.83% preferred stock, and 46.87% common equity. These ratios are appropriate so that the Company can maintain its bond rating, and are within the range of ratios of the companies in the Electric Group and the Gas Group.

COST OF SENIOR CAPITAL

Q. What cost rate have you assigned to the long-term debt portion of the capital structure?

A. The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is due to the fact that the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Schedule 7, I have computed the actual embedded cost rate of long-term debt at December 31, 2003. On page 2 of Schedule 7, I have shown the estimated embedded cost rate of long-term debt at December 31, 2004. The development of the individual effective cost rates for each series of long-term debt, using the cost rate to maturity technique, is shown on page 3 of Schedule 7. The cost rate, or yield to maturity ("ytm"), is the rate of discount that equates the present value of all future interest and principal payments with the net proceeds of the bond. I should note that in developing the net proceeds ratio for use in the ytm calculation, the current amount outstanding was used along with the unamortized balance of the issuance costs. The resulting net proceeds ratio using the present amount outstanding provides a reasonable estimate of the original net proceeds ratio when the debt series were originally issued.

I will adopt the 6.43% embedded cost of long-term debt at December 31, 2004, as shown on page 2 of Schedule 7. This rate is related to the amount of long-term debt shown on Schedule 6 which provides the basis for the 51.30% long-term debt ratio. In my calculation of the embedded cost of long-term debt, I have recognized the costs associated with the Company's early redemption of high cost debt. As previously explained, it is necessary to compensate PPL Electric for the costs incurred to lower the embedded debt cost rate which reduces the cost of capital charged to ratepayers.

Q. What preferred stock cost rate have you calculated for the Company?

A. For the future test year, I have calculated a 6.19% embedded cost of preferred stock as shown on page 2 of Schedule 8. I have included in the embedded cost rate of preferred stock the unrecovered issuance costs and the call premium on the redemption of the preferred and preference stock. The unrecovered issuance expenses and the call premium has been amortized over the original remaining term of the issue. This procedure was adopted because of the difficulty of assigning those costs to a specific replacement issue. These adjustments correspond to those which I previously discussed concerning the Company's capital structure ratios. I will adopt the 6.19% embedded cost of preferred stock, which is related to the 1.83% preferred stock ratio shown on Schedule 6. The details regarding the individual cost rates for each series of preferred stock are provided on page 3 of Schedule 8.

COST OF EQUITY DETERMINATION

Q. Please describe the process you employed to determine the cost of equity for the Company.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among the Company, the Electric Group, the Gas Group, and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I describe in Appendix D. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As noted in Appendix D, and elsewhere in my direct testimony, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I have applied each of these methods and determined that the cost of equity is in the range of 11.00% to 11.75%, from which an 11.50% rate of return on common equity has been proposed. The 11.50% rate of return on common equity reflects the uncertainties associated with the end of the transition period, the Company's credit quality that is presently viewed negatively, narrowly defined sources cash flow, accelerating levels of capital expenditures, and in recognition of the exemplary performance by the Company's management.

DISCOUNTED CASH FLOW ANALYSIS

Q. Please describe your use of the Discounted Cash Flow approach to determine the cost of equity.

A. The details of my use of the DCF approach and the calculations and evidence in support of my conclusions are set forth in Appendix E. I will summarize them here. The Discounted Cash Flow ("DCF") model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stocks consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The cost of equity based on a combination of these two components represents the total return that investors can expect with regard to an equity investment.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations, which include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the rate of return necessary to compensate the utility for the risks that are developing.

As I describe in Appendix E, the DCF approach also has certain limitations that diminish its usefulness in the ratesetting process when stock prices diverge significantly from book values. When stock prices diverge from book values by a significant margin, the DCF method will lead to a misspecified cost of equity.

If regulators rely upon the results of the DCF (which are based on the market price of the stock of the companies analyzed) and apply those results to a net original cost (book value) rate base, the resulting earnings will not produce the level of required return specified by the model when market prices vary from book value. That is to say, such distortions tend to produce DCF results that understate the cost of equity to regulated firms when using a book value rate base. As I will explain later in my testimony, the DCF model can be modified to account for the inadequacies in the model when market prices and book values diverge.

Q. Please explain the dividend yield component of the DCF analysis.

A. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended January 2004, the monthly dividend yields for the Electric Group and the Gas Group are shown graphically on Schedule 9. The monthly dividend yields shown on Schedule 9 include an adjustment to the month-end prices to reflect the build up of the dividend in the price that has occurred since the last ex-dividend date (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). An explanation of this adjustment is provided in Appendix E.

For the twelve months ended January 2004, the average dividend yield was 4.85% for the Electric Group, and 4.19% for the Gas Group, based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three-month periods were 4.61% and 4.46%, respectively, for the Electric Group; and 4.04% and 3.97%, respectively, for the Gas Group. I have used, for the purpose of my direct testimony, a dividend yield of 4.61% for the Electric Group, and 4.04% for the Gas Group, which represents the six-month average yield. The use of this dividend yield will reflect current capital costs while avoiding spot yields.

For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investor anticipated future cash flows. I have adjusted the six-month average dividend yield in three different but generally acceptable manners, and used the average of the three adjusted values as calculated in Appendix E. The adjusted dividend yield is 4.75% for the Electric Group, and 4.18% for the Gas Group.

Q. **Please explain the underlying factors that influence investors' growth expectations.**

A. As noted previously, investors are interested principally in the future growth of their investment (i.e., the price per share of the stock). As I explain in Appendix E, future earnings per share growth represents their primary focus because under the constant price-earnings multiple assumption of the DCF model, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth. The variables that can be considered include: earnings, dividends, book value, and cash flow stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely available to investors. A fundamental growth rate analysis can also be formulated, which consists of internal growth ("b x r"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. The internal growth rate can be modified to account for sales of new common stock -- this is called external growth ("s x v"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value.

Fundamental growth, which combines internal and external growth, provides an explanation of the factors that cause book value per share to grow over time. Hence, a fundamental growth rate analysis is duplicative of expected book value per share growth.

Q. *What investor-expected growth rate is appropriate in a DCF calculation?*

A. Although some DCF proponents would advocate that mathematical precision should be followed when selecting a growth rate (i.e., precise input variables employed within the confines of fundamental growth as described above), the fact is that investors, when establishing the market prices for a firm, do not behave in the same manner assumed by the constant growth rate models using accounting values necessary to calculate fundamental growth. Rather, investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. I followed an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner. Therefore, in my opinion, all relevant growth rate indicators using a variety of techniques should be evaluated when formulating a judgment of investor expected growth.

Q. Before presenting your analysis of the growth rates that apply specifically to the Electric Group and the Gas Group, can you provide an overview of the macroeconomic factors that influence investor growth expectations for common stocks?

A. Yes. As a preliminary matter, it is useful to view macroeconomic forecasts that influence stock prices. After all, the significant increase in stock prices in 2003 can be attributed to a strengthening of business activity. Forecast growth of the Gross Domestic Product ("GDP") can represent the starting point for this analysis. The GDP has both a "product side" and "income side" components. The product side of the GDP is comprised of: (i) personal consumption expenditures; (ii) gross private domestic investment; (iii) net exports of goods and services; and (iv) government consumption expenditures and gross investment. On the income side of the GDP, the components are: (i) compensation of employees; (ii) proprietors' income; (iii) rental income; (iv) corporate profits; (v) net interest; (vi) business transfer payments; (vii) indirect business taxes; (viii) consumption of fixed capital; (ix) net receipts/payment to the rest of the world; and (x) statistical discrepancy. The "product side," (i.e., demand components) could be used as a long-term representation of revenue growth for public utilities. However, it is well known that revenue growth does not necessarily equal earnings growth. There is no basis to assume that the same growth rate would apply to revenues and all components of the cost of service, especially after the troublesome issues of employee's costs, insurance costs, and fuel costs are resolved in the long-term for public utilities. The earnings growth rates for utilities will be substantially affected by changes in operating expenses and capital costs. At present, there is bearishness sentiment for the industry, especially electric utilities that face uncertain prospects after emerging from the transition period that followed restructuring. Negative sentiment has arisen from uncertain regulatory policies following the transition period, and significant cost pressures, especially in the area of employee costs (i.e., pension and health care benefits), insurance costs, and fuel and purchase power costs. The dilutive impact of recent sales of new common stock has also had a negative affect on the earnings prospects of electric utilities.

The long-term consensus forecast that is published semi-annually by the Blue Chip Economic Indicators ("Blue Chip") should be used as the source of macroeconomic growth. Blue Chip is a monthly publication that provides forecasts incorporating a wide variety of economic variables assembled from a panel of more than 50 noted expert economists from the banking, investment, industrial, and consulting sectors whose advice affects the investment activities of market participants. It is always preferable to use a consensus forecast taken from a large panel of contributors, rather than to rely upon one source that may not be representative of the types of information that have an impact on investor expectations. Indeed, Blue Chip is frequently quoted in "The Wall Street Journal," "The New York Times," "Fortune," "Forbes," and "Business Week." Twice annually, Blue Chip provides long-range consensus forecasts. Based upon the October 10, 2003 issue of Blue Chip, those forecasts are:

Year	Nominal GDP	Corporate Profits, Pretax
2005	5.2%	10.1%
2006	5.2	7.1
2007	5.1	6.6
2008	5.3	6.3
2009	5.3	5.7
2005-2009 average	5.2	7.2
2010-2014 average	5.3	6.1

These forecasts show that growth in corporate profits will exceed growth in overall GDP. It is also indicated historically that the percentage change in Corporate Profits has been higher than the percentage change in GDP[3]. From these data, growth in Corporate Profits of about 6% would represent an overall benchmark for the long-term growth component of the DCF.

Q. What data have you considered in your growth rate analysis for the Electric Group and the Gas Group?

A. The bar graphs provided on Schedule 10 show the historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Electric Group and the Gas Group. Value Line serves as the source of the historical growth rates shown on Schedule 10. As shown on Schedule 10, the historical earnings per share growth rates were non-existent (i.e., they were negative) for the Electric Group and 4.31% to 5.75% for the Gas Group. As just noted, the historical growth rates contain instances of negative values for individual companies within the groups. Obviously, negative growth rates provide no reliable guide to gauge investor expected growth for the future. Investor expectations always encompass long-term positive growth rates and, as such, could not be represented by sustainable negative rates of change. Therefore, historical statistics that include negative growth rates should not be given any weight when formulating a composite rate growth rate expectation of investors. The prospect of rate increases granted by regulators, the continued obligation to provide service as required by customers and the ongoing growth of customers mandate investor expectations of positive future growth rates. Stated simply, there is no reason for investors to expect that a utility will wind up its business and distribute its common equity capital to shareholders, which would be symptomatic

3Since 1929, after excluding corporate losses during the Great Depression.

of a long-term permanent earnings decline. Although investors have knowledge that negative growth and losses can occur, their expectations always include positive growth. Negative historic values will not provide a reasonable representation of future growth expectations because, in the long run, investors will always expect positive growth. Indeed, rational investors always expect positive returns, otherwise they will hold cash rather than invest with the expectation of a loss.

Schedule 11 shows projected earnings per share growth rates taken from analysts' forecasts provided in First Call/IBES, Zacks, Reuters/Market Guide and the Value Line publications. The First Call/IBES, Zacks, and Reuters/Market Guide forecasts are restricted to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on Schedule 11.

As to five-year forecast growth rates, Schedule 11 indicates that the projected earnings per share growth rates are 3.78% to 5.72% for the Electric Group and 5.38% to 6.71% for the Gas Group. In each instance, the Value Line projections indicate that earnings per share will grow prospectively at a more rapid rate than dividends per share which indicates a declining payout ratio in the future. This means that with the constant price-earnings multiple assumption of the DCF model, stock price growth for these companies will occur at the higher earnings per share, thus producing the capital gains yield expected by investors. That is to say, stock price growth will exceed dividend growth during the period of declining dividend payout ratios.

Q. What conclusion have you drawn from these data?

A. Although ideally historical and projected earnings per share and dividends per share growth indicators would be used to provide an assessment of investor growth expectations for a firm, the circumstances of the Electric Group and the Gas Group mandate that the greatest emphasis be placed upon projected earnings per share growth, after first considering the macroeconomic factors that influence growth in corporate profits. The massive restructuring of the utility industries suggests that historical evidence does not represent a complete measure of growth for these companies. Indeed, the present bearishness for the electric and gas sectors will eventually give way to more positive sentiment after current uncertainties have been resolved.

It is appropriate to consider all forecasts of growth in earnings that are available to investors. In this regard, I have considered the forecasts from First Call/IBES, Zacks, Reuters/Market Guide, and Value Line. The First Call/IBES, Zacks and Reuters/Market Guide growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The First Call/IBES, Zacks and Reuters/Market Guide estimates are obtained from the Internet and are widely available to investors free-of-charge. First Call is quoted frequently in The Wall Street Journal and Barron's The Dow Jones Business and Financial Weekly when reporting on earnings forecasts. Multex Investor published by Reuters provides the Market Guide forecasts have been, according to Barron's, rated the top website for company research. The Value Line forecasts are also widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries.

Historical performance and published forecasts support my opinion that a company-specific growth rate of 5.50% is indicated for the Electric Group, and 6.25% is indicated for the Gas Group. While the DCF growth rate cannot be established solely by mathematical formulation, the prospective growth rates are within the array of earnings per share growth rates shown by the analysts' forecast. As previously indicated, the restructuring and consolidation now taking place in the utility industry creates additional opportunities (both regulated and non-regulated) as the utility industry successfully adapts to the new business environment. These changes in growth fundamentals will undoubtedly develop beyond the next five years typically considered in the analysts' forecasts that will enhance the growth prospects for the future.

Q Please explain why these figures do not provide a complete representation of the cost of equity?

A. As noted previously and as demonstrated in Appendix E, the divergence of stock prices from book values creates a conflict when the results of a market-derived cost of equity are applied to the common equity account measured at book value, which is the measure used in setting utility rates. This is the situation today where the market price of stock exceeds its book value for the companies in my proxy groups. 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.

Q. What are the implications of a DCF derived return that is related to market value when the results are applied to the book value of a utility's capitalization?

A. The capital structure ratios measured at its book value show more financial leverage, and hence higher risk, than the capitalization measured at its market values. Please refer to Appendix E for the comparison. This means that a market-derived cost of equity, using models such as DCF and CAPM, reflects a level of financial risk that is different from the book value capitalization that is used for ratesetting purposes. Hence, it is necessary to adjust the market-determined cost of equity upward to reflect the higher financial risk related to the book value capitalization that is used for ratesetting purposes. Failure to make this modification would result in a mismatch of the lower financial risk related to market value used to measure the cost of equity and the higher financial risk of the book value capital structure used in the ratesetting process. That is to say, the cost of equity that is related to the common equity ratio using book value has higher financial risk than the common equity ratio using market values. Because the ratesetting process utilizes the book value capitalization, it is necessary to adjust the market-determined cost of equity for the higher financial risk related to the book value of the capitalization.

In pioneering work, Nobel laureates Modigliani and Miller[4] developed several theories about the role of leverage in a firm's capital structure. As part of that work, Modigliani and Miller established that as the borrowing of a firm increases, the expected return on stockholders' equity also increases. This principle is incorporated into my leverage adjustment, which recognizes that the expected return on equity

[4] Modigliani, F. and Miller, M.H. "The Cost of Capital, Corporation Finance, and the Theory of Investments."*American Economic Review*, June 1958, 261-297.

Modigliani, F. and Miller, M. H. "Taxes and the Cost of Capital: A Correction." *American Economic Review*, June 1963, 433-443.

increases to reflect the increased risk associated with the higher financial leverage shown by the book value capital structure, as compared to the market value capital structure that contains lower financial risk.

Q. How is the DCF-determined cost of equity adjusted for the financial risk associated with the book value of the capitalization?

A. Modigliani and Miller proposed several approaches to quantify the equity return associated with various degrees of debt leverage in a firm's capital structure. These formulas point toward an increase in the equity return associated with the higher financial risk of the book value capital structure. The procedure used in making my adjustment consists of a three step process, the first and third steps having multiple parts. In step one, the DCF cost of equity is calculated using the market price of stock and the capital structure ratios are computed from the market capitalization of both the debt and equity of a firm. In step two, a completely unlevered cost of equity is calculated, as if the firm were 100% equity financed. In the third step, a relevered cost of equity is calculated with the capital structure determined from the book value capitalization.

As detailed in Appendix E, the Modigliani and Miller theory shows that the cost of equity increases by 0.44% (10.69% - 10.25%) for the Electric Group and 0.79% (11.22% - 10.43%) for the Gas Group when the common equity ratio declines from the market value to the book value of equity. This type of adjustment has been employed in the cost equity determinations by the Commission in its decisions dated January 10, 2002 for Pennsylvania-American Water Company at Docket No. R-00016339, dated August 1, 2002 for Philadelphia Suburban Water Company in Docket No. R-

00016750, and dated January 29, 2004 for Pennsylvania American Water Company at Docket No. R-00038304.

Q. Please provide the DCF return based upon your preceding discussion of dividend yield, growth, and leverage.

A. As previously explained, I have utilized a six-month average dividend yield ("D_1/P_0") adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate ("g") developed previously. The DCF also includes the leverage modification ("*lev.*") to recognize that the book value equity ratio is used in the ratesetting process rather than the market value equity ratio related to the price of stock.

The resulting DCF cost rate is:

	D_1/P_0	+	g	+	*lev.*	=	k
Electric Group	4.75%	+	5.50%	+	0.44%	=	10.69%
Gas Group	4.18%	+	6.25%	+	0.79%	=	11.22%

The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains the constant growth assumption. I should reiterate, however, that under this form of the DCF model, the indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiples. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market because price-earnings multiples do not remain constant.

RISK PREMIUM ANALYSIS

Q. Please describe your use of the Risk Premium approach to determine the cost of

equity.

A. The details of my use of the Risk Premium approach and the evidence in support of my conclusions are set forth in Appendix G. I will summarize them here. With this method, the cost of equity capital is determined by reference to corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital.

Q. What long-term public utility debt cost rate did you use in your risk premium analysis?

A. In my opinion, a 7.00% yield represents a reasonable estimate of the prospective long-term debt cost rate for an A-rated public utility bond. As I will subsequently show, the Moody's index and the <u>Blue Chip</u> forecasts support this figure.

The historical yields for long-term public utility debt are shown graphically on page 1 of Schedule 12. For the twelve months ended January 2004, the average monthly yield on Moody's A rated index of public utility bonds was 6.51%. For the six- and three-month periods ending January 2004, the yields were 6.43% and 6.26%, respectively.

Q. What are the implications of emphasizing recent data taken from a period of relatively low interest rates?

A. It appears obvious that if interest rates rise from their current low levels, the overall cost of capital and cost of equity determined from recent data will understate future capital costs. Although it is always possible that interest rates could move lower, this possibility is out-weighed by the prospect of higher future interest rates. That is to say, there is more potential for higher rather than lower interest rates when the beginning point in the process contains low interest rates. Short-term interest rates have been at abnormally low levels due to policy actions by the Federal Open Market Committee ("FOMC"). The FOMC policy now appears to be in transition. Indeed, The Wall Street Journal (see issue dated March 17, 2004) reported on strategies that might be employed by the FOMC to implement higher interest rates. The article does not question whether interest will increase, but rather the means that will be employed to achieve higher interest rates. When interest rates do move up, a rate of return established from a period of low interest rates will not provide the Company with a realistic opportunity to achieve reasonable returns in a higher cost of capital environment.

Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the forecast yields on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in yields that I describe in Appendix F. The Blue Chip is published monthly and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A rated public utility bonds because the Fed deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on February 1, 2004 and the yield spread of 1.50% that I describe in Appendix F. This spread can be traced to a general aversion to risk. For comparative purposes, I have also shown the Blue Chip yields on Aaa rated and Baa rated corporate bonds. These forecasts are:

	Blue Chip Financial Forecasts				
	Corporate bonds		Long-Term	A-rated Utility	
Quarter	Aaa rated	Baa rated	Treasury	Spread	Yield
1st Qtr. 2004	5.7%	6.7%	5.1%	1.50%	6.60%
2nd Qtr. 2004	5.9	6.8	5.3	1.50	6.80
3rd Qtr. 2004	6.1	7.0	5.5	1.50	7.00
4th Qtr. 2004	6.2	7.2	5.7	1.50	7.20
1st Qtr. 2005	6.5	7.3	5.8	1.50	7.30
2nd Qtr. 2005	6.6	7.5	6.0	1.50	7.50

Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecast of interest rates. In its December 1, 2003 publication, the Blue Chip published forecasts of interest rates are reported to be:

	10-Year Treasury	Long-Term Treasury	Aaa Corporate	Baa Corporate
2005	5.6%	6.1%	6.9%	7.9%
2006	6.0	6.5	7.3	8.2
2007	6.2	6.7	7.6	8.5
2008	6.3	6.8	7.7	8.6
2009	6.3	6.7	6.7	8.6
2005-09 (avg)	6.1	6.6	7.2	8.4
2010-14 (avg)	6.1	6.7	7.6	8.4

These forecasts show that for the rate effective period interest rates will likely be well above current levels. Given these forecasts and the historical long-term interest rates, a 7.25% yield on A-rated public utility bonds represents a reasonable expectation, especially with the widespread forecasts of higher interest rates later in 2004.

Q. What equity risk premium have you determined for public utilities?

A. Appendix G provides a discussion of the financial returns that I relied upon to develop the appropriate equity risk premium. I have calculated the equity risk premium by comparing the market returns on utility stocks and the market returns on utility bonds. I chose the S&P Public Utility index for the purpose of measuring the market returns for utility stocks because it is intended to represent firms engaged in regulated activities and today is comprised of electric companies and gas companies. The S&P Public Utility index contains companies that are more closely aligned with the electric utility industry than some broader market index, such as the S&P 500 Composite index. The S&P Public Utility index is a subset of the overall S&P 500 Composite index. Use of the S&P Public Utility index reduces the role of subjective judgment in establishing the risk premium for public utilities. With the equity risk premiums developed for the S&P Public Utilities as a base, I derived the equity risk premium for the Electric Group and Gas Group.

Q. What equity risk premium for the S&P Public Utilities have you determined for this case?

A. To develop an appropriate risk premium, I analyzed the results for the S&P Public Utilities by averaging (i) the midpoint of the range shown by the geometric mean and median and (ii) the arithmetic mean. This procedure has been employed to provide a comprehensive way of measuring the central tendency of the historical returns. As shown by the values indicated on page 2 of Schedule 13, the indicated risk premiums for the various time periods analyzed are 4.88% (1928-2003), 5.52% (1952-2003), 4.49% (1974-2003), and 4.47% (1979-2003). The selection of the shorter periods from the entire historical series is designed to provide a risk premium that conforms more nearly to present investment fundamentals and removes some of the more distant data from the analysis.

Q. Do you have further support for the selection of time periods used in your equity risk premium determination?

A. Yes. First, the terminal year of my analysis presented in Schedule 13 represents the returns realized through 2003. Second, the selection of the initial year of each period was based upon the events that I describe in Appendix G. These events were fixed in history and cannot be manipulated as later financial data becomes available. That is to say, using the Treasury-Federal Reserve Accord as a defining event, the year 1952 is fixed as the beginning point for the measurement period regardless of the financial results that subsequently occurred. Likewise, 1974 represented a benchmark year because it followed the 1973 Arab Oil embargo. Also, the year 1979 was chosen because it began the deregulation of the financial markets. As such, additional data is merely added to the earlier results when it becomes available, clearly showing that the periods chosen were not driven by the desired results of the study.

Q. What conclusions have you drawn from these data?

A. Using the summary values provided on page 2 of Schedule 13, the 1979-2003 period provides the lowest indicated risk premium, while the 1952-2003 period provides the highest risk premium for the S&P Public Utilities. Within these bounds, a common equity risk premium of 4.69% (4.88% + 4.49% = 9.37% ÷ 2) is shown from the data covering the periods 1928-2003 and 1974-2003. Therefore, 4.69% represents a reasonable risk premium for the S&P Public Utilities in this case.

As noted earlier in my fundamental risk analysis, differences in risk characteristics must be taken into account when applying the results for the S&P Public Utilities to the Electric Group and Gas Group. I recognized these differences in the development of the equity risk premium in this case. I previously enumerated various differences in fundamentals between the Electric Group and Gàs Group and the S&P Public Utilities, including size, market ratios, common equity ratio, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds, and betas. In my opinion, these differences indicate that 4.50% represents a reasonable common equity risk premium for the Electric Group and the Gas Group. These values represents approximately 96% (4.50% ÷ 4.69% = .96) of the risk premium of the S&P Public Utilities and is reflective of the risk of the Electric Group and the Gas Group as compared to the S&P Public Utilities.

Q. What common equity cost rate would be appropriate using this equity risk premium and the yield on long-term public utility debt?

A. The cost of equity (i.e., "*k*") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "*i*") and the equity risk premium (i.e., "*RP*"). The Risk Premium approach provides a cost of equity of:

	i	+	*RP*	=	*k*
Electric Group	7.25%	+	4.50%	=	11.75%
Gas Group	7.25%	+	4.50%	=	11.75%

CAPITAL ASSET PRICING MODEL

Q. How have you used the Capital Asset Pricing Model to measure the cost of equity in this case?

A. I have used the Capital Asset Pricing Model ("CAPM") in addition to my other methods. As with other models of the cost of equity, the CAPM contains a variety of assumptions that I discuss in Appendix H. Therefore, this method should be used to complement the results of other methods.

Q. What are the features of the CAPM as you have used it?

A. The CAPM contains the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. The details of my use of the CAPM and evidence in support of my conclusions are set forth in Appendix H. To compute the cost of equity with the CAPM, three components are necessary, i.e., a risk-free rate of return ("*Rf*"), the beta measure of systematic risk ("β"), and the market risk premium ("*Rm* - *Rf*") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or portfolio of firms and the entire market of equities. As such, to calculate the CAPM, it is necessary to employ firms with traded stocks. In this regard, I have performed a CAPM calculation for the Electric Group and the Gas Group.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 1 of Schedule 14, the betas are .66 for the Electric Group and .69 for the Gas Group.

Q. What betas have you used in the CAPM determined cost of equity?

A. The betas must be reflective of the financial risk associated with the ratesetting capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM unless those betas are applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book value capital structure, the Value Line betas have been unleveraged and releveraged for the common equity ratios using book values. This adjustment has been made with the formula:

$$\beta l = \beta u \, [1 + (1 - t)\, D/E + P/E]$$

where βl = the leveraged beta, βu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and therefore are related to the market value capitalization that contains common equity ratios of 49.79% for the Electric Group and 58.94% for the Gas Group. By using the formula shown above and the capital structure ratios measured at its market values, I calculated the betas if there were no leverage in the capital structure (i.e., they were 100% equity financed). With the unleveraged beta as a base, I calculated the leveraged betas for the Electric Group and the Gas Group associated with book value capital structure.

The betas and corresponding common equity ratios are:

	Market Values		Book Values	
	Beta	Common Equity Ratio	Beta	Common Equity Ratio
Electric Group	.66	49.79%	.73	43.38%
Gas Group	.69	58.94%	.82	47.04%

The leveraged betas that I will employ in the CAPM cost of equity are .73 for the Electric Group and .82 for the Gas Group.

Q. What risk-free rate have you used in the traditional CAPM?

A. For reasons explained in Appendix F, I have employed the yields on long-term Treasury bonds using both historical and forecast data to match the longer-term horizon associated with the ratesetting process. As shown on page 2 of Schedule 14, I have provided the historical yields on long-term Treasury bonds. For the twelve months ended January 2004, the average yield was 5.01%, as shown on page 3 of that schedule. For the six- and three- months ended January 2004, the yields on long-term Treasury bonds were 5.21% and 5.13%, respectively. As shown on page 4 of Schedule 14, forecasts published by Blue Chip on February 1, 2004 indicate that the yields on long-term Treasury Bonds are expected to increase to the 5.8% to 6.0% during the first and second quarters of 2005 when rates take effect in 2005. The longer term forcasts described previously show that the yields on Treasury bonds will remain at or above 6% from 2005 through 2014. To conform with the use of historical and forecast data that I employ in my analysis, I have used a 5.75% risk-free rate of return for CAPM purposes.

Q. What market premium have you used in the traditional CAPM?

A. As discussed in Appendix H, the market premium is developed by averaging historical market performance (i.e., 6.6%) with the Value Line forecast (i.e., 4.98%). The resulting market premium is 5.79% (6.6% + 4.98% = 11.58% ÷ 2).

Q. Are there adjustments to the CAPM that are necessary to fully reflect the rate of return on common equity?

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. There would be an understatement of the cost of equity using the CAPM unless the size of a firm is considered. That is to say, as the size of a firm decreases, its risk, and hence its required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs then otherwise similar larger firms (see Fundamentals of Financial Management, fifth edition, page 623). Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock Effect," it was demonstrated that the CAPM could understate the cost of equity significantly according to a company's size. Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. In this regard, the Electric Group had an average market capitalization of $2,460 million, and the Gas Group had an average market capitalization of $1,491 million. According to the SBBI Yearbook, the Electric Group and the Gas Group must be viewed as mid-cap companies. This would indicate a size premium of 0.82% for the Electric Group and the Gas Group. Absent the size adjustment, the CAPM would understate the required return.

Q. What CAPM result have you determined using the traditional CAPM?

A. Using the 5.75% risk-free rate of return, the leverage adjusted betas of .73 for the Electric Group and .82 for the Gas Group, and the 5.79% market premium, and the size premium noted above, the following results are indicated:

	Rf	+	*β*	*(Rm-Rf)*	=	*k*	+	*size*	=	*K*
Electric Group	5.75%	+	.73	(5.67%)	=	9.89%	+	0.82%	=	10.71%
Gas Group	5.75%	+	.82	(5.67%)	=	10.40%	+	0.82%	=	11.22%

COMPARABLE EARNINGS APPROACH

Q. How have you applied the Comparable Earnings approach in this case?

A. The details of my Comparable Earnings approach and the evidence in support of my conclusion are set forth in Appendix I. To implement the Comparable Earnings approach, I have used both historical realized returns and forecast returns for non-utility companies. I have not used returns for utility companies so as to avoid the circularity that arises from using regulatory influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (5 historical years and 5 projected years) is sufficient to cover an average business cycle[5]. The results of the Comparable Earnings method can be applied directly to an original cost rate base because the nature of the analysis relates to book value. Hence, Comparable Earnings do not contain the potential misspecification contained in market models when prices and book values diverge significantly.

Q. What are the results of your Comparable Earnings analysis?

A. The process that I used to select the Comparable Earnings companies is described in Appendix I and is shown on page 1 of Schedule 15. The historical rate of return on book common equity was 14.7% using the median measure of central tendency as shown on page 2 of Schedule 15. The forecast rate of return as published by Value Line is shown by the 13.8 % median value also provided on page 2 of Schedule 15.

5 For example, since 1854, there has been 30 business cycles having an average length of 51 months measured from trough to trough and 53 months measured from peak to peak. Hence, a 10-year measurement period in the Comparable Earnings approach is more than adequate to cover an average business cycle.

Q. What rate of return on common equity have you determined in this case using the Comparable Earnings approach?

A. The average of the historical and forecast median rates of return is 14.25% (14.7% + 13.8% = 28.5% ÷ 2) and represents the Comparable Earnings result for this case.

<u>CREDIT QUALITY AND CONCLUSION</u>

Q. What are some of the important factors that influence credit quality?

A. The Company must have the financial strength that will, at a minimum, permit it to maintain a financial profile that is commensurate with the requirements to obtain a solid investment grade bond rating.

A variety of quantitative and qualitative measures must be considered when assessing the credit quality of an appropriate rate of return on common equity. In quantitative terms, two of the measures of credit quality considered by the bond rating agencies are debt leverage and pre-tax interest coverage. In the area of coverage, the rate of return on common equity represents a critical component because it is the equity return that provides the margin whereby an interest coverage multiple greater than one is realized.

Q. Why is it important that a utility maintain strong credit quality?

A. Strong credit quality is necessary to provide a utility with the highest degree of financial flexibility in order to attract capital on reasonable terms during all economic conditions. Customers also benefit from strong credit quality because the utility will be able to obtain lower financing costs that are passed on to customers in the form of a lower embedded cost of debt. For this reason, rates should be established that would involve the maintenance of a financial profile that would support a strong A bond rating that is the appropriate regulatory objective.

Q. What credit quality measures are reflected in the 8.80% rate of return that has *been proposed by the Company in this case?*

A. Public utilities must compete in the capital markets to attract needed future capital and, as such, interest coverage should be used as a test to measure the adequacy of the rate of return. Of course, it is not the only factor to be considered in testing the appropriate rate of return and must be viewed in relation to an individual company's degree of financial leverage and cash flow benchmarks. Using a 41.4935% composite federal and state income tax rate, Schedule 1 shows that the implicit level of pre-tax coverage of interest expense would be 3.85 times based upon the overall rate of return that the Company has proposed. The 3.85 times pre-tax interest coverage and 51.30% debt ratio shown on Schedule 1 should be viewed in the context of the S&P credit quality rating criteria that I previously discussed. It is important to recognize that the benchmarks represent levels expected to be achieved, rather than the opportunity provided by the rate of return used in the ratesetting process. It is my opinion that the Company's rates should be established at a level that would provide the Company with an opportunity to attain the credit quality profile no weaker than that reflected on Schedule 1.

Q. What is your conclusion concerning the Company's cost of equity?

A. Based upon the application of a variety of methods and models described previously, it is my opinion that the 11.50% rate of return on common equity is appropriate for the Company and provides recognition for the uncertainty surrounding the fundamentals that will exist after the end of the transition period, the Company's credit quality that is presently viewed negatively, narrowly defined sources of cash flow, accelerating levels of capital expenditures, and the exemplary performance of its management. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method. In conclusion, the Company is entitled to an 11.50% rate of return on common equity so that it can compete in the capital markets, maintain reasonable credit quality, and receive recognition of the significant accomplishments that management has achieved.

Q. Does this conclude your direct testimony?

A. Yes.