BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE PETITION OF THE	)	
CITY OF RICHMOND, INDIANA, BY ITS	)	
MUNICIPAL ELECTRIC UTILITY,	)	
RICHMOND POWER & LIGHT FOR	)	**CAUSE NO. 42713**
APPROVAL OF A NEW SCHEDULE OF RATES	)	
AND CHARGES FOR ELECTRIC SERVICE	)	

DIRECT TESTIMONY OF
WILLIAM STEVEN SEELYE

PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC

On Behalf of the Petitioner,
Richmond Power & Light

Petitioner's Exhibit WSS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6435 West Highway 146, Crestwood, Kentucky, 40014.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of cost of service, rate design, utility marketing, and regulatory analysis,.

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

A. The purpose of my testimony is to analyze Richmond Power & Light's ("RP&L's") electric revenue requirements for the 12 months ended March 31, 2004; to sponsor a fully allocated class cost of service study based on RP&L's embedded costs for the 12 months ended March 31, 2004; to describe the proposed allocation of the revenue increase; and to sponsor RP&L's proposed rates for electric service.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Prime Group performed an analysis of RP&L's revenue requirements for the 12 months ended March 31, 2004. RP&L's revenue requirements were analyzed using two standard methodologies commonly used in the industry – (1) the rate of return or utility approach, and (2) the cash revenue requirements or cash needs approach. The utility approach, which is the methodology generally used by investor-owned utilities, would support an increase in annual operating revenues of $4.7 million. The cash revenue requirements approach, a methodology frequently used by municipal utilities to determine the need for a rate increase would support an increase in annual operating revenues of $4.8 million. RP&L's proposed increase in annual operating revenues of $3.5 million is well below the increase that could be supported by either of these standard revenue requirements methodologies.

The Prime Group prepared a fully allocated, embedded cost of service study for RP&L's test-year operations using standard methodologies. The purpose of the cost of service study is to determine the contribution that each customer class is making towards RP&L's overall rate of return. Rates of return are computed for each rate class. RP&L was guided by the embedded cost of service study in allocating the proposed revenue increase to the classes of service and in developing the proposed rates.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is divided into the following sections: (I) Qualifications, (II) Revenue Requirement, (III) Cost of Service Study, and (IV) Allocation of the Rate Increase and Rate Design.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PRIOR WORK EXPERIENCE.

A. I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From May 1979 until July 1996, I was employed by Louisville Gas and Electric Company ("LG&E"). From May 1979 until December, 1990, I held various positions within the Rate Department of LG&E. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left LG&E in July 1996 to form The Prime Group, LLC, with two other former employees of LG&E.

Since leaving LG&E, I have provided consulting services to numerous investor-owned utilities, rural electric cooperatives, and municipal utilities regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs. Specifically, I have prepared and filed Order No. 888 and Order No. 889 compliance filings at the Federal Energy Regulatory Commission ("FERC") for a number of electric utilities as well as Order No. 888 and Order No. 889 waiver requests for other utilities. I have prepared market power analyses in support of market-based rate filings at FERC for utilities and their marketing affiliates, as well as assisting other utilities with their market-based rate filings. I have provided utility clients with assistance regarding regulatory policy and strategy; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives; the unbundling of rates and the development of menus of rate alternatives for use with customers; and performance-based rate development.

Q. HAVE YOU EVER TESTIFIED BEFORE ANY STATE OR FEDERAL REGULATORY COMMISSIONS?

A. Yes, on a number of occasions. In Alabama, I testified in Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments. In Colorado, I testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case. I testified before the FERC in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment. In Florida, I testified in Docket No. 981827 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole Electric Cooperative Inc.'s wholesale rates and cost of service. In Illinois, I testified in Docket No. 01-0637 on behalf of Central Illinois Light Company ("CILCO") concerning the modification of interim supply service and the implementation of black start service in connection with providing unbundled electric service.

In Kentucky, I testified on behalf of Louisville Gas and Electric Company ("LG&E") in Administrative Case No. 244 regarding rates for co-generators and small power producers. I testified on behalf of LG&E in Case No. 8924 regarding marginal cost of service and in numerous fuel adjustment clause ("FAC") proceedings. I testified in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg City's Utilities Commission rates. I testified in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. concerning its rate stabilization plan. I testified in Case No. 99-176 on behalf of Delta Natural Gas Company, Inc. concerning cost of service, rate design and expense adjustments. In Case No. 2000-080, I testified on behalf of LG&E concerning cost of service, rate design, and pro-forma adjustments to revenues and expenses. I submitted rebuttal testimony in Case No. 2000-548 on behalf of LG&E regarding the company's prepaid metering program. I submitted testimony on behalf of LG&E in Case No. 2002-00430 and on behalf of Kentucky Utilities Company ("KU") in Case No. 2002-00429 regarding the calculation of merger savings. I submitted testimony on behalf of LG&E in Case No. 2003-00433 regarding gas and electric cost of service studies, revenue allocation, rate design, and pro-forma adjustments and on behalf of KU in Case No. 2003-00434 regarding electric cost of service studies, revenue allocation, rate design, and pro-forma adjustments. I submitted testimony on behalf of Delta Natural Gas Company in Case No. 2004-00067 concerning cost of service, temperature normalization, depreciation rates, revenue allocation, and rate design.

In Nevada, I testified before the Public Utilities Commission of Nevada on behalf of Nevada Power Company in Case No. 03-10001 regarding cash working capital. I also testified before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company in Case No. 03-12002 regarding cash working capital.

Q. HAVE YOU DEVELOPED RATES FOR MUNICIPAL UTILITIES AND ELECTRIC COOPERATIVES?

A. Yes, I supervised the development of revenue requirements and the proposed rates for several municipal electric, water and sewer utilities, including Prestonsburg, Kentucky; Pikeville, Kentucky; Fountain, Colorado; Olive Branch, Mississippi; and Livermore, Iowa. I have supervised the preparation of cost of service studies and the development of retail rates for over 100 electric cooperatives around the country.

Q. HAVE YOU DEVELOPED ELECTRIC RATES FOR UTILITIES IN INDIANA?

A. Yes. I supervised the development of wholesale rates and the open access transmission tariff ("OATT") for Hoosier Energy Rural Cooperative. I also supervised the preparation of cost of service studies and electric rates for Johnson County REMC, Davies-Martin REMC, and Clark County REMC. I also supervised the preparation of the OATT for Southern Indiana Gas and Electric Company.

II. REVENUE REQUIREMENTS

Q. DID YOU PERFORM AN ANALYSIS COMPUTING RP&L'S REVENUE REQUIREMENTS?

A. Yes.

Q. HOW WERE REVENUE REQUIREMENTS DETERMINED?

A. RP&L's revenue requirements were calculated using two different methodologies – (i) the utility approach and (ii) the cash needs approach. Under the *utility approach*, revenue requirements include a representative level of operation and maintenance expenses on a going forward basis, depreciation expenses, a reasonable return on utility investment, and tax expenses (as applicable). The return component of revenue requirements is typically determined on the basis of a fair, just and reasonable return on rate base. Using the utility approach, revenue requirements are determined as follows:

Rev Req = O&M Expenses + Depreciation + (ROR x Rate Base) + Taxes

Rate base includes net plant (utility plant in service less accumulated depreciation) plus working capital consisting of materials and supplies, cash working capital, and prepayments. The utility approach is the standard methodology used to determine revenue requirements for investor-owned utilities and some cooperatives and municipal utilities when they are regulated by state regulatory commissions. A standard procedure for applying the utility approach is to determine the level of revenue sufficient to produce an operating income that generates a fair, just and reasonable rate of return on rate base.

Under the *cash needs* approach, revenue requirements include a level of operation and maintenance expenses representative on a going forward basis, debt service requirements, capital expenditures not debt financed, and tax payments (as applicable). Using the cash needs approach, revenue requirements are determined as follows:

Rev Req = O&M Expenses + Debt Costs + Cap Exp + Tax Payments

When using the cash needs approach, a times-interest-earned (TIER) component will often be included as a part of the utility's debt service costs. The cash needs approach is a methodology commonly used by municipal utilities and rural electric cooperatives.

Q. HAVE YOU PREPARED AN EXHIBIT SHOWING THE DETERMINATION OF REVENUE REQUIREMENTS USING THE UTILITY APPROACH?

A. Yes. Exhibit WSS-1 is an income statement shown on an actual basis, pro-forma basis and adjusted for the required increase in revenue. Column B shows the actual results for RP&L's electric operations for the 12 months ended March 31, 2004. Column C shows the pro-forma adjustments made to reflect the going-forward level of operational results. Column D shows the alphanumerical designations (e.g. A01, A02, etc.) used to identify each pro-forma adjustment. Column E shows the pro-forma statement of operating income reflecting the pro-forma adjustments shown in Column C. Column F shows the pro-forma adjustments required to produce RP&L's proposed revenue requirements and operating income, and Column G shows alphanumerical designations identifying the proposed adjustment. Column H shows the pro-forma statement of operating income including the additional revenue requirements for RP&L's electric operations.

Q. WHAT ARE THE ACTUAL OPERATING RESULTS AND THE EFFECT OF THE PRO FORMA ADJUSTMENTS SHOWN ON EXHIBIT WSS-1?

A. The actual operating income for the 12 months ended March 31, 2003, as shown on Column B, Line 14 of Exhibit WSS-1 is $370,112. On a pro-forma basis, RP&L would experience an operating loss for the test year. The pro-forma operating income shown on Column E, Line 14, corresponds to a loss of ($248,218), as adjusted for the pro-forma margin and expense adjustments shown in Column C. These pro-forma adjustments are necessary to reflect, on a full twelve-month basis, fixed, known and measurable changes to RP&L's actual test-year results.

A revenue increase of $4,701,016 would be required to provide a 7.00% return on RP&L's net original cost rate base. This increase in revenue is shown on Column F, Line 4. The $4,701,016 revenue increase is required to produce the required operating income of $4,386,983 as shown on Column H, Line 14. Dividing the operating income of $4,386,983 by the net cost rate base of $62,671,188 produces a rate of return of 7.00%.

Q. PLEASE DESCRIBE THE DETERMINATION OF RP&L'S NET COST RATE BASE.

A. The development of RP&L's net cost rate base is shown on Exhibit WSS-2. Net cost rate base consists of net utility plant (utility plant in service less accumulated depreciation) as of the end of the test year plus working capital consisting of materials and supplies, cash working capital, and prepayments. Contributions in aid of construction (CIAC) were explicitly removed from plant in service. Materials and supplies and prepayments were determined on the basis of 13-month average balances. RP&L elected not to include a cash working capital component in rate base. RP&L's net cost rate base as of March 31, 2004, was $62,671,188.

Q. PLEASE DESCRIBE EXHIBIT WSS-3.

A. Exhibit WSS-3 consists of 20 pages and includes the support for each pro-forma adjustment and the proposed revenue increase. This exhibit includes 9 separate attachments labeled Adjustment A01 through Adjustment A09 that describe each pro-forma adjustment.

Q. PLEASE DESCRIBE ADJUSTMENTS A01, A02, AND A05 SHOWN IN EXHIBIT WSS-3.

A. Adjustment A01 and A02 are pro-forma adjustments to RP&L's test year operating revenues. Adjustment A01 is an adjustment to operating revenues to reflect the effect of two large industrial customers switching from one rate schedule to another. Adjustment A01 thus reflects test-year billings for these two customers at the current rates.

Adjustment A02 is an adjustment to reflect the loss in revenue due to a plant closing by a large industrial customer, Engine Products Division of Dana Corporation. Engine Products Division, which had operated a foundry in RP&L's service territory, closed its foundry operations in February, 2004. RP&L collected $1,571,118 in revenues from this customer during the 12 months ended March 31, 2004. These revenues will not be received in the future and consequently have been removed from test-year operating results. A corresponding expense adjustment of $1,360,225 was made to reflect a reduction in purchased power expenses during the test year for this customer. The expense adjustment is shown as adjustment A05. There are currently no prospects for a new customer to be served at this facility.

Q. PLEASE DESCRIBE ADJUSTMENT A03 SHOWN IN EXHIBIT WSS-3.

A. Adjustment A03 reflects an increase in operating and maintenance expenses based on the current level of wages, fringe benefits and payroll taxes. This adjustment includes an annualization of a 3.0% wage increase for all employees. The pro-forma adjustment was determined by subtracting (a) the pro-forma level of annual labor expenses from (b) the test-year payroll expenses.

Q. PLEASE DESCRIBE ADJUSTMENT A04 THAT IS SHOWN IN EXHIBIT WSS-3.

A. Adjustment A04 represents an adjustment to increase test-year expenses for the estimated incremental rate case costs associated with this proceeding. RP&L is proposing a three-year amortization of these costs. We anticipate that this adjustment will be subsequently adjusted to reflect the actual costs incurred in connection with this proceeding.

Q. PLEASE DESCRIBE ADJUSTMENT A06 SHOWN IN EXHIBIT WSS-3.

A. Adjustment A06 reflects the pro-forma increase in depreciation expense based on electric utility plant balances at March 31, 2003. Line 1 represents the depreciation expenses per books for the test year. Line 2 represents the pro-forma depreciation expenses based on the electric utility plant balances by account number as of March 31, 2004, and the applicable depreciation rates currently in effect. The pro-forma increase in depreciation expenses of $48,083 is shown on line 3 and on the bottom right hand cover of page 2 of Adjustment A06.

Q. PLEASE DESCRIBE ADJUSTMENT A07 SHOWN IN EXHIBIT WSS-3.

A. Adjustment A07 shows an increase in the Indiana Utility Receipts Tax ("IURT") as a result of a notification in early 2004 that receipts collected from the City of Richmond and the school district for the sale of electricity are not tax exempt. During the test year, IURT expenses were computed assuming that these receipts were tax exempt.

Q. PLEASE DESCRIBE ADJUSTMENT A08 SHOWN IN EXHIBIT WSS-3.

A. Adjustment A08 shows the calculation of the increased revenue requirement for RP&L's electric operations necessary to provide a 7.00% return on net original cost rate base. The 7.00% rate of return is discussed later in my testimony. The increased revenue requirement is calculated by determining the required increase in operating income. The required operating income is determined by applying the proposed rate of return of 7.00% to the net original cost rate base shown on Exhibit WSS-2. The increase in operating income is then grossed up for the Utility Receipts taxes. The proposed increase in revenue requirements to provide a 7.00% return on net original cost rate base is $4,701,016.

Q. PLEASE DESCRIBE ADJUSTMENT A09 SHOWN IN EXHIBIT WSS-3.

A. Adjustment A09 is a calculation of the Indiana Utility Receipts Taxes applicable to the proposed increase in revenue requirements, and is calculated by applying the 1.4% rate to the proposed increase in revenue requirements.

Q. PLEASE EXPLAIN WHY IN YOUR OPINION A RATE OF RETURN OF 7.0% WOULD REPRESENT A FAIR, JUST AND REASONABLE RETURN FOR RP&L.

A. In contrast to an investor-owned utility, RP&L is owned by a municipal government and not by a group of investors. To continue to operate successfully and provide safe and reliable service to its customers, RP&L must be able to earn a fair, just and reasonable return on its invested property, just like an investor-owned utility. A typical investor-owned utility would finance its operations using a composite of equity financing and debt financing. For example, a typical investor-owned utility might finance 50% of its rate base or capital requirements with long-term debt and 50% with equity. Because owning equity entails greater risk to investors than first mortgage bonds (viz. because debt holders have priority over owners of preferred or common stock), the cost of equity for a typical investor-owned utility will be anywhere from 400 to 800 basis points higher than the cost of debt. Therefore, if a utility's debt cost is 6% per annum, its cost of equity might be 12.0%. If the utility's capital structure consists of 50% debt and 50% equity, its weighted cost of capital would be 9.0% (50% x 6.0% + 50% x 12.0% = 9.0%).

I indicated earlier in my testimony that The Prime Group works with cooperative and municipal utilities all over the country. The trend for these utilities is to try and operate their organizations as solid business enterprises. As a result, more and more cooperative and municipal utilities are establishing revenue requirements that will provide them the opportunity to earn a reasonable return on rate base, and not merely a minimum revenue level sufficient to meet cash flow requirements. These utilities will typically set their rates at a level that will provide for an overall rate of return on rate base in the range of 200 to 400 basis points above the long-term cost of debt. Therefore, if the long-term cost of debt is 5.0%, then the utility might establish rates that will provide an opportunity to earn a rate of return on rate base of between 7.0% and 9.0%.

Q. IS THERE A THEORETICAL BASIS FOR ESTABLISHING RATES BASED ON AN OVERALL RATE OF RETURN THAT IS GREATER THAN THE COST OF DEBT?

A. Yes. As mentioned earlier, the cost of equity is greater than the cost of debt. Equity holders assume greater risks than debt holders thus receiving a "premium" for the risks that investors take by owning equity shares rather than, say, long-term mortgage bonds. Thus, the cost of equity reflects a premium above the cost of debt. Mathematically, this can be described by the following formula:

$$R_e = R_d + \text{Risk Premium},$$

where, R_e represents the return on equity and R_d represent the cost of debt. Because a utility's capital structure will consist of some combination of equity and debt, the weighted cost of capital generally will be higher than the cost of debt. If P_d represents the percentage of a utility's capital structure comprising debt, and P_e represents the percentage of capital structure comprising equity, the weighted cost of capital (ROR) can be stated as follows:

$$\begin{aligned} ROR &= R_d \text{ x } P_d + R_e \text{ x } P_e \\ &= R_d \text{ x } P_d + (R_d + \text{Risk Premium}) \text{ x } P_e \\ &= R_d \text{ x } P_d + (R_d + \text{Risk Premium}) \text{ x } (1\text{-} P_d) \\ &= R_d + \text{Risk Premium x } (1\text{-} P_d) \end{aligned}$$

Therefore, regardless of the amount of leverage, the weighted cost of capital will always be greater than the cost of debt.[1]

Q. IS THERE A BASIS FOR ESTABLISHING A RATE OF RETURN THAT IS 200 TO 400 BASIS POINTS ABOVE THE COST OF DEBT?

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1 This is a reformulation of the famous Miller-Modigliani (M-M) model that can be found in almost any graduate-level financial management textbook. Miller and Modigliani showed that in the absence of income taxes (which is the case for most municipal utilities), the cost of equity is equal to a constant average cost of capital plus a risk premium which depends on the degree of leverage (i.e., R_e = ROR + Risk Premium). One of the important conclusions from the M-M model is that in the absence of income taxes the overall rate of return for a firm is unaffected by its capital structure. For example, see F. Modigliani and M. H. Miller, "The Cost of Capital, Corporation Finance and the Theory of Investment," *American Economic Review*, volume 48 (June 1958), 261-297.

A. Because equity shares of municipal and cooperative utilities are not traded on any stock exchange, we must rely on judgment and on comparisons with other utilities, including our experience with both not-for-profit utilities and investor-owned utilities. As I indicated earlier, many not-for-profit utilities are establishing utility rates designed to produce a rate of return on rate base that is 200 to 400 basis points above their cost of debt. Likewise, the overall rates of return (weighted cost of capital) for investor owned utilities are currently being awarded in the range of 100 to 400 basis points above the cost of long-term debt.

Q. DOES RP&L HAVE ANY LONG-TERM DEBT?

A. No. For a period of years, RP&L has financed its operations entirely with internally generated funds rather than issue debt. It is not uncommon for municipal and cooperative utilities to finance their operations predominantly or entirely with equity.

Q. DOES THIS SUGGEST THAT RP&L'S WEIGHTED COST OF CAPITAL IS LOWER THAN IF IT FINANCED A PORTION OF ITS OPERATIONS WITH DEBT?

A. No. Established economic theory suggests that RP&L's overall cost of capital would be the same regardless of the level of its leverage.[2]

Q. HAVE YOU EXAMINED THE COST OF LONG-TERM MUNICIPAL BONDS?

2 Ibid.

A. Yes. I examined the Municipal Bond Index that is published daily by Standard & Poor's ("S&P"). The average yield to maturity based on the Municipal Bond Index published on September 22, 2004, was 4.88%. This yield has remained in the 4.8-5.0% during the past month.

Q. IN YOUR OPINION, WHAT IS A REASONABLE RATE OF RETURN ON RATE BASE FOR RP&L?

A. A rate of return in the range of 6.9% to 8.9% would be reasonable. The bottom end of the range was determined by adding 200 basis points to the S&P Municipal Index yield to maturity (rounded to the nearest 10th percentage point) of 4.9%. The top end of the range was determined by adding 400 basis points to the yield to maturity. In computing RP&L's revenue requirements under the utility approach we used 7.0% as the required return on rate base, which is toward the lower end of this range.

Q. HAVE YOU PREPARED AN EXHIBIT SHOWING THE DETERMINATION OF RP&L'S REVENUE REQUIREMENTS USING THE CASH NEEDS APPROACH?

A. Yes. Exhibit WSS-4 shows the revenue requirement determined using the cash needs approach. Using this methodology, net revenue requirement reflects operation and maintenance expenses plus normalized capital expenditures ("extensions and replacements"). Test-year operation and maintenance expenses were revised to reflect the following pro-forma adjustments: (i) labor expense adjustment (A03), (i) amortization of rate case expenses (A04), (iii) reduced purchase power expenses from no longer serving Engine Products Division (A05), and (iv) the correction in the IURT expenses (A07). Operating expenses were not adjusted to reflect the annualization of depreciation expenses because depreciation does not affect cash flow. Extensions and replacements were determined by calculating a five-year average of RP&L capital expenditures for the period 2002 through 2006. Extensions and replacements for the years 2002-2003 were based on actual expenditures and the extensions and replacements for the years 2004-2006 were based on budgeted expenditures. Based on this analysis, RP&L's net revenue requirement would be $67,861,084. Subtracting RP&L's test-year revenue (adjusted for known and measurable changes to test-year results) from the cash needs revenue requirement results in a revenue deficiency of $4,818,016. Exhibit WSS-5 shows that a revenue increase of $4,818,016, as determined using the cash needs approach, would produce a rate of return on rate base of 7.17%.

Q. WHAT IS THE REVENUE INCREASE PROPOSED BY RP&L?

A. The Richmond Common Council, the municipal legislative body for Richmond, Indiana, has authorized, through an ordinance, an increase in annual operating revenues of $3,500,000 and a rate of return on rate base of approximately 5.2%. (It should be noted that RP&L's proposed rates, when applied to test-year billing determinants, actually produce an increase of $3,501,421, due to rounding of the unit charges.)

Q. HOW DOES RP&L'S PROPOSED INCREASE COMPARE TO THE INCREASES THAT CAN BE SUPPORTED BY THE UTILITY APPROACH AND THE CASH NEEDS APPROACH?

A. As mentioned earlier, the utility approach for computing revenue requirements would support an increase of $4,701,016, and the cash needs approach would support an increase of $4,818,016. Therefore, RP&L's proposed revenue increase of $3,501,421 is significantly below the level of increase supported by either the utility approach or cash needs approach.

Q. WHAT RATE OF RETURN IS PRODUCED BY RP&L'S PROPOSED REVENUE INCREASE?

A. A revenue increase of $3,501,421 will produce a rate of return on rate base of 5.1% based on pro-forma operating results for the 12 months ended March 31, 2003. This computation is shown in Exhibit WSS-6. A rate of return of 5.1% is well below the 6.9% to 8.9% level that would be reasonable, and is approximately the same as the current yields on municipal bonds, which is currently in the 4.8-5.0% range.[3]

3 See above.

III. COST OF SERVICE STUDY

Q. DID YOU PREPARE A COST OF SERVICE STUDY FOR RP&L BASED ON FINANCIAL AND OPERATING RESULTS FOR THE 12 MONTHS ENDED MARCH 31, 2004?

A. Yes. I supervised the preparation of a fully allocated, embedded cost of service study for RP&L's electric operations for the 12 months ended March 31, 2004. The cost of service study corresponds to the pro-forma financial exhibit included in Exhibit WSS-1. The objective in performing the electric cost of service study is to determine the rate of return on rate base that RP&L is earning from each customer class, which provides an indication as to whether RP&L's service rates reflect the cost of providing service to each customer class.

Q. DID YOU DEVELOP THE MODEL USED TO PERFORM RP&L'S COST OF SERVICE STUDIES?

A. Yes. I developed the spreadsheet model used to perform the cost of service study being submitted in this proceeding.

Q. WHAT PROCEDURE WAS USED IN PERFORMING THE COST OF SERVICE STUDY?

A. The three traditional steps of an embedded cost of service study – functional assignment, classification, and allocation – were used to perform the cost of service study for RP&L. The cost of service study was therefore prepared using the following procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups; (2) costs were then *classified* as commodity-related, demand-related, or customer-related; and then (3) costs were allocated to RP&L's rate classes. These steps are depicted in the following diagram (Figure 1).

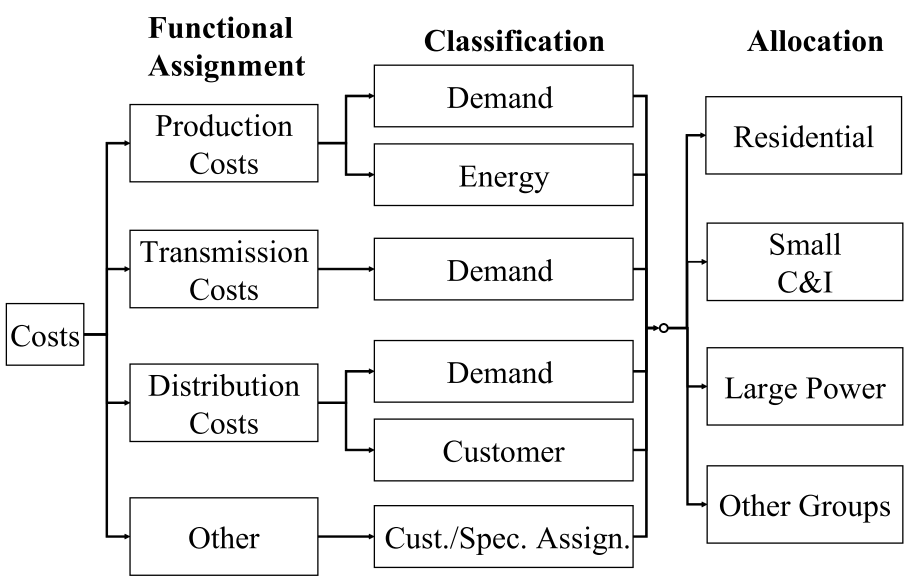

Figure 1

The following functional groups were identified in the cost of service study: (1) Production, (2) Transmission, (3) Distribution Substation (4) Distribution Primary Lines, (5) Distribution Secondary Lines (6) Distribution Line Transformers, (7) Distribution

Services, (8) Distribution Meters, (9) Distribution Street Lighting, (10) Customer Accounts Expense, (11) Customer Service and Information, and (12) Customer Lighting.

Q. HOW WERE COSTS CLASSIFIED AS ENERGY RELATED, DEMAND RELATED OR CUSTOMER RELATED?

A. Classification provides a method of arranging costs so that the service characteristics that give rise to the costs can serve as a basis for allocation. Costs classified as *energy related* tend to vary with the amount of kilowatt-hours consumed. Fuel and purchased power expenses are examples of costs typically classified as energy costs. Costs classified as *demand related* tend to vary with the capacity needs of customers, such as the amount of generation, transmission or distribution equipment necessary to meet a customer's needs. Production plant and the cost of transmission lines are examples of costs typically classified as demand costs. Costs classified as *customer related* include costs incurred to serve customers regardless of the quantity of electric energy purchased or the peak requirements of the customers and include the cost of the minimum system necessary to provide a customer with access to the electric grid. As will be discussed later in my testimony, costs related to Distribution Primary Lines, Distribution Secondary Lines and Distribution Line Transformers were classified as demand-related and customer-related using the zero-intercept methodology. Distribution Services, Distribution Meters, Distribution Street and Customer Lighting, Customer Accounts Expense, Customer Service and Information and Sales Expense were classified as customer-related.

Q. HOW WERE RP&L'S PRODUCTION COSTS CLASSIFIED?

A. RP&L purchases all of its power requirements from Indiana Municipal Power Agency ("IMPA"). In addition, RP&L owns and operates a power plant; however, all of the demand and energy from the plant is sold to IMPA under the terms of a Capacity Purchase Agreement. Therefore, it was necessary to classify three categories of production-related costs and revenues: (i) purchased power expenses recorded in Account No. 555 reflecting demand and energy purchases from IMPA, (ii) the fixed and variable costs of RP&L's power plant, and (iii) revenues collected from the sale of power to IMPA (which has the effect of reducing RP&L's revenue requirements). In the cost of service study, all fixed costs, including revenues and purchased power costs billed on a demand basis, were classified as demand-related. All variable costs, including revenues and purchased power costs billed on an energy basis, were classified as energy-related.

Q. HAVE YOU PREPARED AN EXHIBIT SHOWING THE RESULTS OF THE FUNCTIONAL ASSIGNMENT AND CLASSIFICATION STEPS OF THE ELECTRIC COST OF SERVICE STUDY?

A. Yes. Exhibit WSS-7 shows the results of the first two steps of the electric cost of service study – functional assignment and classification.

Q. PLEASE DESCRIBE THE ALLOCATION FACTORS USED IN THE ELECTRIC COST OF SERVICE STUDY.

A. The following allocation factors were used in the RP&L cost of service study:

- **E01** – The energy components of purchased power costs, fuel, variable production expenses, and power sales to IMPA were allocated on the basis of the kWh sales to each class of customers during the test year.
- **12CP** – The demand components of purchased power expenses, production costs, transmission costs, and power sales to IMPA were allocated on the basis of each class's contribution to RP&L's 12-month average coincident peak demand. The demand charges in RP&L's monthly power bills from IMPA are billed on a monthly coincident peak basis. Likewise, the demand charges billed to IMPA for power sales from RP&L are billed on a monthly coincident peak basis.
- **NCPP** – The demand cost components of distribution poles, distribution substations, and primary distribution lines are allocated on the basis of the maximum class demands for primary and secondary voltage customers.
- **SICD** – The demand cost components of secondary distribution lines and line transformers are allocated on the

basis of the sum of individual customer demands for secondary voltage customers.

- **C02** – Customer services are allocated on the basis of the average number of customers for the test year weighted by the cost of services for each type of customer.
- **C03** – Meter costs are allocated on the basis of the average number of customers for the test year weighted by the cost of meters for each type of customer.
- **YECust04** – Costs associated with street lighting systems were specifically assigned to the street lighting classes of customers.
- **C05 and C06** – Meter reading, billing costs and customer service expenses were allocated on the basis of a customer weighting factor based on discussions with RP&L's administrative staff.
- **YECust07** – The customer cost component is allocated on the basis of the year-end number of customers taking service at secondary voltage.
- **YECust08** – The customer cost component is allocated on

the basis of the year-end number of customers taking service at primary and secondary voltage.

- **YECust09** – Costs associated with customer lighting systems were specifically assigned to the customer lighting class of customers.

Q. IN YOUR COST OF SERVICE MODEL, ONCE COSTS ARE FUNCTIONALLY ASSIGNED AND CLASSIFIED, HOW ARE THESE COSTS ALLOCATED TO THE CUSTOMER CLASSES?

A. In the cost of service model used in this study, RP&L's accounting costs are functionally assigned and classified using what are referred to in the model as "functional vectors". These vectors are multiplied (using *scalar multiplication*) by the various accounts in order to simultaneously assign costs to the functional groups and classify costs. Therefore, in the portion of the model included in Exhibit WSS-7, RP&L's accounting costs are functionally assigned and classified using the explicitly determined functional vectors of the analysis and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on pages 57 through 60. Internally generated functional vectors are utilized throughout the study to functionally assign costs on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are also shown on pages 57 through 60 of Exhibit WSS-7.

An example of this process is the use of payroll expenses ("LBSUB7") to allocate Account 926 - Employee Benefits. Because pension expenses are associated with employee payroll costs, it is appropriate (and a standard approach in the industry) to functionally assign and classify these costs on the same basis as payroll costs. (See Exhibit WSS-7, pages 29 through 32 for the functional assignment of employee benefits expenses on the basis of LBSUB7 shown on pages 45 through 48.) The functional vector used to allocate a specific cost is identified by the column in the model labeled "Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name".

Once costs for all of the major accounts are functionally assigned and classified, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors". This process is illustrated in Figure 2 below.

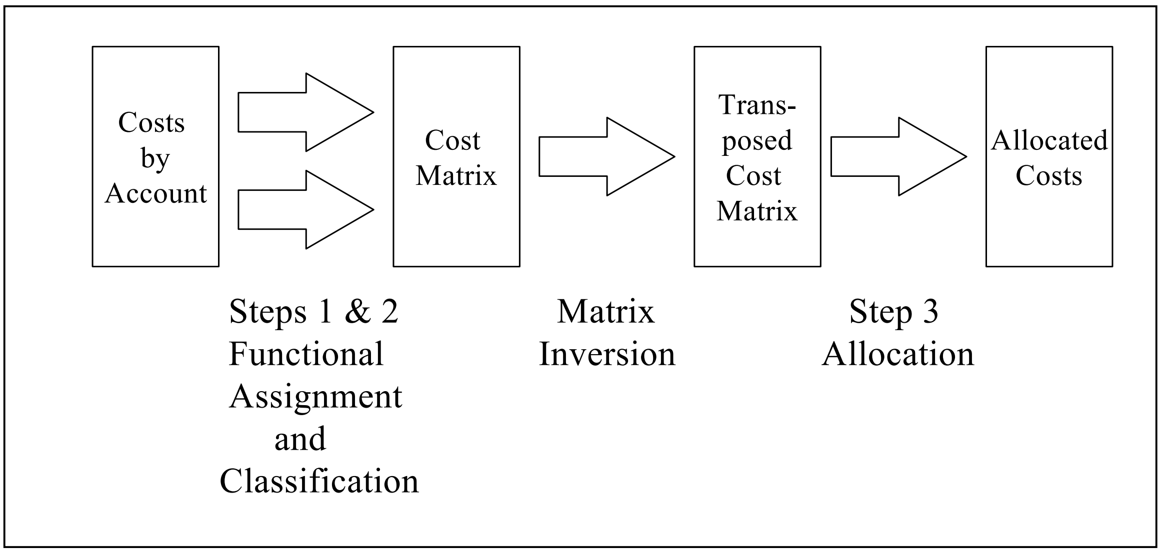

Figure 2

The results of the class allocation step of the cost of service study *on an unadjusted basis* are included in Exhibit WSS-8. The results of the class allocation step of the cost of service study *on a pro-forma or adjusted basis* are included in Exhibit WSS-9. The costs shown in the column labeled "Total System" in Exhibits WSS-8 and WSS-9 were carried forward *from* the functionally assigned and classified costs shown in Exhibit WSS-7. The columns labeled "Ref" in Exhibits WSS-8 and WSS-9 provide a reference to the results included in Exhibit WSS-7.

Q. WHAT METHODOLOGIES ARE COMMONLY USED TO CLASSIFY DISTRIBUTION PLANT?

A. Two commonly used methodologies for determining demand/customer splits of distribution plant are the "minimum system" methodology and the "zero-intercept" methodology. In the minimum system approach, "minimum" standard poles, conductors, and line transformers are selected and the minimum system is obtained by pricing all of the applicable distribution facilities at the unit cost of these minimum size facilities. The minimum system determined in this manner is then classified as customer-related and allocated on the basis of the number of customers in each rate class. All costs in excess of the minimum system are classified as demand-related. The theory supporting this approach maintains that in order for a utility to serve even the smallest customer, it would have to install a minimum size system. Therefore, the costs associated with the minimum system are related to the number of customers that are served, instead of the demand imposed by the customers on the system.

The zero-intercept methodology was used in RP&L's cost of service study because it is less subjective than the minimum system approach and is strongly preferred over the minimum system methodology when the necessary data is available. With the zero intercept methodology, we are not forced to choose a minimum size conductor or line transformer to determine the customer component. In the zero-intercept methodology, a zero-size conductor or line transformer is the absolute minimum system.

Q. WHAT IS THE THEORY BEHIND THE ZERO-INTERCEPT METHODOLOGY?

A. The theory behind the zero intercept methodology is that there is a linear relationship between the unit cost ($/ft or $/transformer) of conductors or line transformers and the load flow capability of the plant, which is proportionate to the cross-sectional area of the conductor or the kVA rating of the transformer. After establishing a linear relation, which is given by the equation:

$$y = a + bx$$

where:

y is the unit cost of the conductor or transformer,

x is the size of the conductor (MCM) or transformer (kVA), and

a, **b** are the coefficients representing the intercept and slope, respectively

it can be determined that, theoretically, the unit cost of a foot of conductor or transformer with zero size (or conductor or transformer with zero load carrying capability) is **a**, the zero intercept. The zero intercept is essentially the cost component of conductor or transformers that is invariant to the size (and load carrying capability) of the plant.

Like most electric utilities, the number of line transformers on RP&L's distribution system is not uniformly distributed over all transformer sizes. For example, RP&L has over 1,600 25.0 KVA transformers, but only one 2,300 KVA transformer. For this reason, it was necessary to use a weighted regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept. Without performing a weighted regression analysis both transformer sizes would have the same impact on the analysis, even though there are over a thousand times more 25.0 KVA transformers than 2,300 KVA transformers.

Using a weighted regression analysis, the cost and size of each type of conductor or transformer is, in effect, weighted by the number of feet of installed conductor or the number of transformers. In a weighted regression analysis, the following weighted sum of squared differences

$$\sum_i w_i (y_i - \hat{y}_i)^2$$

is minimized, where **w** is the weighting factor for each size of conductor or transformer, and **y** is the observed value and **ŷ** is the predicted value of the dependent variable.

Q. HAVE YOU PREPARED EXHIBITS SHOWING THE RESULTS OF THE ZERO-INTERCEPT ANALYSIS?

A. Yes. The zero-intercept analysis for line transformers is included in Exhibit WSS-10. RP&L did not have the detailed information necessary to perform a zero-intercept analysis for overhead and underground conductors. We attempted to perform a zero-intercept analysis using estimated data, but the R-Square statistics were low and the customer components significantly higher than what we've seen with other distribution systems. Therefore, we developed the customer and demand components for overhead and underground conductors using a panel of zero-intercept results from other utilities.

Q. HAVE YOU PREPARED AN EXHIBIT SHOWING THE DEVELOPMENT OF THE DEMAND ALLOCATORS USED IN THE COST OF SERVICE STUDY?

A. Yes. WSS-11 shows the development of the demand allocation factors from RP&L's load research data. RP&L is somewhat remarkable for a municipal utility of its size in that it has an on-going load research program. Most cooperative and municipal utilities the size of RP&L have not implemented a load research program. Having a load research program significantly improves the accuracy of the cost of service study.

Q. PLEASE DESCRIBE EXHIBIT WSS-12.

A. Exhibit WSS-12 shows the development of the allocation factors for meters and services. These allocation factors were developed based the number of customers weighted by the cost of meters and services for each rate class.

Q. DID YOU PREPARE AN EXHIBIT SHOWING THE SEPARATION OF DISTRIBUTION LINES BETWEEN PRIMARY AND SECONDARY VOLTAGES?

A. Yes. Exhibit WSS-13 shows the results of a study separating overhead and underground conductor between primary and secondary voltages.

Q. PLEASE SUMMARIZE THE RESULTS OF THE ELECTRIC COST OF SERVICE STUDY.

A. The following table (Table 1) in my testimony summarizes the rates of return for each customer class before and after reflecting the rate adjustments proposed by RP&L. The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect the pro-forma adjustments shown in Exhibit WSS-3. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base.

TABLE 1 Class Rates of Return		
Customer Class	**Actual Adjusted Rate of Return**	**Proposed Rate of Return**
Residential - Rate R	(3.20)%	1.74%
Commercial Lighting Service - Rate CL	(12.23)%	(4.82)%
General Power Service – Rate GP	31.53%	31.54%
Outdoor Lighting Service – Rate OL	(9.34)%	(2.72)%
Industrial Service – Rate IS	0.94%	8.74%
Industrial Service Coincident Peak – Rate IS	(3.23)%	3.93%
Large Power Service – Rate LPS	4.25%	10.63%
Large Power Service Coincident Peak – Rate LPS	(2.75)%	3.01%
General Electric Heating – Rate GEH	13.83%	18.88%
Street and Municipal Lighting – Rates N & M	(2.80)%	(1.40)%
Electric Heating Schools – Rate EHS	10.66%	15.50%
Total System	(0.40)%	5.10%

Q. DOES THE COST OF SERVICE STUDY INCLUDE AN ANALYSIS OF THE SUBSIDIES THAT ARE CURRENTLY REFLECTED IN RP&L'S RATES FOR ELECTRIC SERVICE?

A. Yes. The rate subsidies at the current rates are derived on pages 23-24 of Exhibit WSS-9. These subsidies were computed based on a cost of service reflecting a negative 0.40% rate of return on rate base. Therefore, any customer group with a class rate of return below negative 0.40% will show that that customer class is currently *receiving* a subsidy, and any customer group with class rate of return above negative 0.40% will show that

that class is currently *paying* a subsidy. The rate subsidies at the proposed rates are derived on pages of 27-28 of Exhibit WSS-9. Any customer group with a class rate of return below 5.10% will show that that customer class will be *receiving* a subsidy, and any customer group with class rate of return above 5.10% will show that that class will be *paying* a subsidy.

IV. ALLOCATION OF THE REVENUE INCREASE AND RATE DESIGN

Q. HAVE YOU PREPARED AN EXHIBIT RECONSTRUCTING RP&L'S TEST-YEAR BILLING UNITS?

A. Yes. In order to develop RP&L's proposed rates it was necessary to reconstruct test-year billing determinants. The reconstruction of RP&L's billing determinants is shown on WSS-14. As shown on page 1 of Exhibit WSS-14, the revenues calculated on pages 2 through 13 of that exhibit were within a factor of 0.99934 of RP&L's actual revenues, thus confirming the accuracy of the test period billing units.

Q. AFTER CONSIDERING ALL OF THE REQUIRED PRO-FORMA ADJUSTMENTS, WHAT IS THE PROPOSED INCREASE IN REVENUES AND HOW IS THE INCREASE APPORTIONED TO THE INDIVIDUAL CUSTOMER CLASSES?

A. In this filing, RP&L is proposing to increase its annual revenues by $3,501,421. Exhibit WSS-15 shows that the proposed increase would result in an increase of 7.85% in total operating revenue (and 7.83% in sales to ultimate consumers). In addition to requesting an increase in electric service rates, RP&L is also proposing to increase its reconnection charge, thus resulting in an increase in miscellaneous revenue.

The proposed rates apportion the revenue increase among the customer classes as shown in Table 2 below:

TABLE 2
Proposed Revenue Increase

Customer Class	Proposed Increase	Percentage
Residential - Rate R	$ 1,183,849	10.0%
Commercial Lighting Service - Rate CL	$ 486,785	20.00%
General Power Service – Rate GP	$ 265	0.01%
Outdoor Lighting Service – Rate OL	$ 38,040	19.96%
Industrial Service – Rate IS	$ 199,187	7.03%
Industrial Service Coincident Peak – Rate IS	$ 753,423	7.05%
Large Power Service – Rate LPS	$ 724,573	7.04%
Large Power Service Coincident Peak – Rate LPS	$ 48,143	7.05%
General Electric Heating – Rate GEH	$ 14,640	5.04%
Street Lighting Service – Rate N	$ 2,778	5.00%
Municipal Street Lighting Service – Rate M	$ 33,587	5.04%
Electric Heating Schools – Rate EHS	$ 7,616	5.00%
Total Sales to Ultimate Consumers	$ 3,492,886	7.83%

As shown on Exhibit WSS-16, pages 1-12, the increase in revenues for each rate class was determined by applying both the current and proposed charges to the adjusted billing determinants.

Q. WHAT WAS THE BASIC UNDERLYING INFORMATION THAT SUPPORTED THE PROPOSED ALLOCATION OF THE REVENUE REQUIREMENT AMONG RP&L'S RATE CLASSES?

A. The cost of service study provided information measuring the extent to which the revenues generated by each customer class contribute to the overall return earned by RP&L. As shown on Table 1, the cost of service study indicated that the individual class rates of return ranged between -12.23% and 31.53%, as compared to an overall adjusted actual return on rate base of -0.40%, with Rate CL being the lowest at -12.23% and Rate GP being the highest at 31.53%. This indicates a need to increase the revenues collected from some classes more than others.

Q. WHAT WERE THE RATEMAKING OBJECTIVES IN DEVELOPING THE PROPOSED RATES?

A. In general, we tried to develop rates that more closely reflect the cost of providing service. One of our key objectives was to bring the rates of return more in line by allocating relatively more of the revenue increase to the customer classes indicating low rates of return and allocating relatively less of the revenue increase to the customer classes indicating high rates of return. We chose not to decrease the rates to any class even though certain customer classes may indicate high rates of return. For example, the cost of service study indicated a rate of return for General Power – Rate GP of 31.53%. Therefore, for this class, we developed rates that were essentially revenue neutral. On the other extreme, we mitigated the level of increases to classes with low rates of return. For example, a higher increase could have been supported for the residential and small commercial classes, but to avoid rate shock we capped the increases to these classes at 10% and 20%, respectively.

Another key objective was to bring the unit charges more in line with the unit costs derived from the cost of service study. RP&L's rates consist of both two-part rates, consisting of a customer charge and energy charge, and three-part rates, consisting of a customer charge, energy charge and demand charge. Thus, we developed rates that moved these charges toward the unit costs indicated by the cost of service study.

Q. DOES RP&L HAVE A PURCHASED POWER COST ADJUSTMENT?

A. Yes. RP&L has a purchased power cost adjustment that accounts for changes in its purchased power costs from IMPA. The purchased power cost adjustment is computed against a base power cost. With this filing, we are rolling test-year purchased power costs into base rates. Therefore, when the rates go into effect, a new base power cost will be used to determine the purchased power cost adjustment.

Q. IS RP&L PROPOSING ANY CHANGES TO THE PURCHASED POWER COST ADJUSTMENT MECHANISM?

A. No. We are simply rolling test-year purchased power cost in base rates and resetting the base purchased power costs used to apply the purchased power cost adjustment. We are not proposing to change the way that the mechanism operates.

Q. WHAT IS THE PROPOSED REVENUE INCREASE FOR RESIDENTIAL – RATE R?

A. RP&L is proposing a revenue increase of $1,183,849, or 10.0%, for the residential rate class. To eliminate all subsidies to the residential class and produce an overall return on rate base of 5.10%, an increase of $1,967,315, or 16.62%, would have been required. In recognition of the principles of gradualism, rate continuity and customer acceptance, the residential increase was limited to 10.0%.

Q. IS RP&L PROPOSING TO BRING THE RESIDENTIAL CHARGES MORE IN LINE WITH THE UNIT COSTS SHOWN IN COST OF SERVICE STUDY?

A. Yes. We are proposing to increase the monthly residential facilities charge from $6.50 to $10.00 to bring it more in line with the cost of providing service. The cost of service study indicates that the customer cost for the residential class is $18.54 per customer per month. Therefore, we are proposing to increase the customer charge to a level representing only 54% of the cost of providing service. This proposal thus represents a reasonable increase.

Q. WHAT IS THE PROPOSED REVENUE INCREASE FOR COMMERCIAL LIGHTING SERVICE – RATE CL?

A. RP&L is proposing a revenue increase of $486,785, or 20.0%, for Rate CL. The cost of service study indicates that the rate of return for this class is -12.23%, the lowest in the study.

To eliminate all subsidies to Rate CL and produce an overall return on rate base of

5.10%, an increase of $1,122,210, or 46.12%, would have been required. We therefore capped the increase at 20%.

Q. IS RP&L PROPOSING TO BRING THE CHARGES FOR RATE CL MORE IN LINE WITH THE UNIT COSTS SHOWN IN COST OF SERVICE STUDY?

A. Yes. We are proposing to increase the monthly facilities charge from $8.00 to $17.50 to bring it more in line with the cost of providing service. The cost of service study indicates that the customer cost for Rate CL is $20.16 per customer per month.

Q. ARE YOU PROPOSING TO INCREASE THE RATES FOR GENERAL POWER – RATE GP?

A. The charges for Rate GP were designed to be revenue neutral. The cost of service study indicates that the rate of return for Rate GP is 31.53%, the highest rate of return in the study. With its rate of return at 31.53%, a rate increase for Rate GP cannot be justified. By not increasing the rates for this class, RP&L is taking a gradual approach for bringing Rate GP more in line with the cost of providing service. Although the proposed charges for Rate GP are designed to be revenue neutral, the unit charges have been adjusted to reflect the roll-in of purchased power costs into base rates.

Q. WHAT IS THE PROPOSED REVENUE INCREASE FOR OUTDOOR LIGHTING SERVICE – RATE OL?

A. RP&L is proposing a revenue increase of $38,040, or 19.96%, for Rate OL. The cost of service study indicates that the rate of return for this class is -9.34%, the second lowest in the study. To eliminate all subsidies to Rate OL and produce an overall return on rate base of 5.10%, an increase of $81,726, or 42.89%, would have been required. We therefore capped the increase at approximately 20%. In developing the individual lighting charges, we applied the same percentage increase to each type of light.

Q. PLEASE DESCRIBE RP&L'S LARGE POWER RATES AND THE PROPOSED CHANGES TO THESE RATES.

A. RP&L has four large power rates – (i) Industrial Service – Rate IS, (ii) Industrial Service – Rate IS Coincident Peak, (iii) Large Power Service – Rate LPS; and (iv) Large Power Service – Rate LPS Coincident Peak. Rate IS is predicated on customers taking service at primary voltage and Rate LPS is predicated on customers taking service at secondary voltage. The coincident peak rates are currently offered on an experimental basis, with customers billed on the lower of either the experimental coincident peak rate or the standard rate. The reason that RP&L incorporated the provision to bill customers under the lower of the two rates was to eliminate risks to customers in order to encourage them to try the experimental rate. Because the rate schedule has been in place for a number of years, and appears to be suitable for certain large industrial customers, it is no longer necessary to continue to offer the rate on an experimental basis. RP&L is proposing to continue to offer the coincident peak rate on an optional basis, but to modify the rate so customers would no longer be billed under the lower of the two rates. RP&L is also proposing to modify the tariff so that if a customer chooses to take service under the optional coincident peak rate then the customer must remain on the rate schedule for at least 12 months.

RP&L is proposing to increase all four large power rates by approximately 7.0%. Specifically, Industrial Service – Rate IS would be increased by $199,187 or 7.03%; Industrial Service – Rate IS Coincident Peak would be increased by $753,423 or 7.05%; Large Power Service – Rate LPS would be increased by $724,573 or 7.04%; and Large Power Service – Rate LPS Coincident Peak would be increased by $48,143 or 7.05%. The energy charges would be increased and the demand charges decreased to reflect the unit charges shown in the cost of service study.

We also proposing to modify the late payment provisions of Rate IS, Rate IS Coincident Peak, and Rate LPS Coincident Peak so that they will be the same as RP&L's other rate schedules. Rate R, Rate CL, Rate GP, Rate LPS and other rate schedules include a late payment charge of 3% of all bills if the current bill is not paid by the due date indicated on the bill. Rate IS currently provides that interest at 10% per annum would be charged from the due date to the date of payment on all bills not paid in full by the due date. Rate IS Coincident Peak and Rate LPS Coincident Peak currently do not contain late payment charges. RP&L is thus proposing to conform the late payment charges in Rate IS, Rate IS Coincident Peak, and Rate LPS Coincident Peak to the late payment charges included in RP&L's other rate schedules.

Additionally, RP&L is proposing to modify the power factor provisions included in Rate IS Coincident Peak and Rate LPS Coincident Peak to reflect a 96% base power factor rather than the current 95% base power factor. The 96% power factor corresponds to the base power factor used to compute the power factor penalty in IMPA's wholesale power rate.

Q. WHAT ARE THE PROPOSED REVENUE INCREASES FOR THE OTHER RATE CLASSES?

A. RP&L is proposing to increase the revenue to the other rate classes by approximately 5.0%. These rates include: Street Lighting Service – Rate N; Municipal Street Lighting Service – Rate M; General Electric Heating Service – Rate GEH; and Electric Heating Schools – Rate EHS. RP&L is not proposing any fundamental rate design changes to these schedules.

Q. IS RP&L PROPOSING ANY NEW RATE SCHEDULES?

A. Yes. RP&L is proposing new rates schedules for large power transmission voltage customers. The service will be offered on both a non-coincident and coincident peak basis. The charges for Industrial Transmission Service – Rate ITS and Industrial Transmission Service Rate ITS Coincident Peak correspond to the respective Rate IS rates schedules, except that distribution fixed costs have not been included in the demand charges. More specifically, the demand charges for Rate ITS and Rate ITS Coincident Peak include a fixed transmission cost component of $0.71 per kW per month but do not include any fixed distribution demand costs. The $0.71 per kW transmission demand component was derived from the cost of service study. (See page 34 of Exhibit WSS-9.)

RP&L is also proposing a rate schedule that would allow the utility to offer special contracts to non-standard or specialized customer requests for electric services or to meet competitive forces in the market for energy services. A similar rate schedule was approved by the Indiana Utility Regulatory Commission for Indianapolis Power & Light Company.

Q. IS RP&L PROPOSING TO MODIFY ANY OF ITS NON-RECURRING CHARGES?

A. Yes. RP&L is proposing to increase its reconnection charges by $5.00 per reconnect, as follows:

TABLE 3
Proposed Reconnection Fees

Reconnection Fee	Current Charge	Proposed Charge

TABLE 3
Proposed Reconnection Fees

Reconnection Fee	Current Charge	Proposed Charge
At Meter 8 AM-5 PM	$25.00	$30.00
At Pole 8 AM-5 PM	$45.00	$50.00
After Normal Hours	$65.00	$70.00

The $5.00 increase was determined based on an analysis of labor and transportation costs involved in performing reconnections. The cost of disconnecting service was not included in the charge; therefore the charge is conservative. Furthermore, RP&L is proposing charges that are less than the actual cost of reconnecting service. These cost estimates are included in Exhibit WSS-17. RP&L is also proposing a $15.00 charge for all same-day connections (excluding reconnects related to non-payments) requested after 12:30 PM. Given the special attention and effort required to perform same-day connections that are requested late in the business day, a $15.00 charge is clearly reasonable.

Q. HAVE YOU PREPARED AN EXHIBIT SHOWING RP&L'S COMPLETE TARIFF REFLECTING THE PROPOSED RATES?

A. Yes. Exhibit WSS-18 is RP&L's tariff showing the proposed rates.

Q. HAVE YOU PREPARED A RED-LINED VERSION OF THE TARIFF SHOWING THE CHANGES TO THE CURRENT TARIFF?

A. Yes. A red-lined version showing the changes to the current tariff is included in Exhibit WSS-19.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.