ORIGINAL

DEPARTMENT OF THE AIR FORCE
AIR FORCE LEGAL SERVICES AGENCY/UTILITY LITIGATION TEAM
TYNDALL AIR FORCE BASE, FLORIDA

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June 24, 2005

Director
Division of the Commission Clerk
FL PSC
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Tallahassee, Fl 32399-0850

Dear Sir or Madam,

The Federal Executive Agencies, by and through the undersigned counsel of the Air Force Utility Litigation Team, encloses herewith the original and 25 copies for filing of the pre-filed testimony of Matt Kahal in the FP&L rate increase case, **DOCKET NO. 050045-EL**.

Sincerely

Craig Paulson

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STATE OF FLORIDA

BEFORE THE

PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	))	Docket No. 050045-EI

DIRECT TESTIMONY OF

MATTHEW I. KAHAL

ON BEHALF OF THE

FEDERAL EXECUTIVE AGENCIES

JUNE 2005

EXETER

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

STATE OF FLORIDA

BEFORE THE

PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE) BY FLORIDA POWER & LIGHT COMPANY)	Docket No. 050045-EI

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew I. Kahal. I am employed as an independent consultant, retained by the consulting firm Exeter Associates, Inc. My business address is 5565 Sterrett Place, Suite 310, Columbia, Maryland 21044.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I hold B.A. and M.A. degrees in economics from the University of Maryland and have completed all course work and examination requirements for the Ph.D. degree in economics. My areas of academic concentration include industrial organization, economic development and econometrics.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I have been employed in the area of energy, utility and telecommunications consulting for the past 25 years working on a wide range of subjects. Most of my work over the years has focused on utility integrated planning, power plant licensing, environmental compliance, purchase power contracts and a variety of utility ratemaking issues. This has included extensive work on cost of capital and utility financial studies. Much of my professional work in recent years has shifted to electric utility restructuring, mergers and competition.

Prior to entering consulting, I served on the faculties of the University of Maryland (College Park) and Montgomery College, teaching a range of undergraduate courses in economics and business.

Appendix A, which is attached to my testimony, provides a statement of my qualifications.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS?

A. Yes. I have testified before approximately two dozen state and federal utility regulatory commissions in more than 250 separate regulatory cases. My testimony has addressed a wide range of topics including rate of return, need for power, rate design, integrated resource planning, purchase power contracts, stranded costs, utility mergers, and other policy and ratemaking issues. These cases have encompassed electric, gas, telephone and water utilities. I also have testified before the U.S. Congress, Committee on Ways and Means, on proposed tax legislation affecting utilities. These cases are listed in Appendix A.

II. OVERVIEW

A. Recommendation Summary

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

A. I have been retained by the Federal Executive Agencies ("FEA") to evaluate the rate of return request in this case for Florida Power & Light ("FPL" or the "Company"). As part of that assignment, I have prepared an independent study of the cost of common equity relating to the Company's jurisdictional electric service rate base.

Q. WHAT ARE YOU RECOMMENDING AT THIS TIME?

A. I am recommending that this Commission set the authorized rate of return on common equity (ROE) at a figure in the range of 9.0 to 10.0 percent, with a midpoint value of 9.5 percent being a reasonable point value to determine FPL's revenue deficiency in this case. If the projected 2006 test-year capital structure proposed in this case by FPL is employed, this would result in an overall rate of return applicable to an original cost rate base of 6.74 percent. This employs the Company's projected average capital structure and debt cost rates for 2006, my 9.5 percent ROE and a small downward adjustment to FPL's projected cost of debt. My testimony briefly discusses the Company's capital structure and debt cost proposal and my adjustment. My recommendation on the overall rate of return is summarized on Schedule MIK-1, page 1 of 1.

Q. HOW DOES YOUR RECOMMENDATION IN THIS CASE COMPARE WITH THE COMPANY'S PROPOSAL?

A. The Company in this case is requesting 8.22 percent, including a common equity return of 12.3 percent, which incorporates a 50 basis point (0.5 percent) performance bonus. The requested rate of return is sponsored by Company witness Dewhurst, but the Company's cost of equity witness is Dr. William Avera. Dr. Avera concludes that the cost of equity applicable to FPL at this time is 11.8 percent, which is inclusive of 0.3 percent for flotation expense. After including the 50 basis points for performance (sponsored by Mr. Dewhurst), he obtains his final ROE recommendation of 12.3 percent.

Q. HOW DID DR. AVERA CONDUCT HIS COST OF EQUITY STUDY?

A. Dr. Avera applied the DCF model to a proxy group of single A-rated electric utilities, obtaining a return estimate (as of March 2005) of 9.4 percent. He then performed a series of three risk premium studies, obtaining estimates ranging from 9.7 to 11.8 percent, based on his "current estimate" of market interest rates. However, his "test year" risk premium results, based on assumed <u>increases</u> in market interest rates from current levels, range from 10.9 to 12.0 percent. Combining the DCF and risk premium evidence, he concludes that the cost of equity for FPL is 10.0 to 12.0 percent, or 10.3 to 12.3 percent with his 30 basis point flotation expense adder.

Q. GIVEN THESE DCF AND RISK PREMIUM RETURN CALCULATIONS, HOW DID HE DEVELOP HIS FPL ROE RECOMMENDATION OF 12.3 PERCENT?

A. Dr. Avera next increases his lower end 10.3 percent result to 11.3 percent in order to address "the need for FPL to attract capital under adverse circumstances" (page 4), thereby obtaining an ROE range of 11.3 to 12.3 percent. To the midpoint of this range of 11.8 percent, he adds the 50 basis point performance bonus, producing a final recommended ROE award of 12.3 percent.

Q. HOW DID YOU OBTAIN YOUR RECOMMENDED 9.5 PERCENT RETURN ON EQUITY RECOMMENDATION?

A. I conducted a standard DCF study applied to a proxy group of electric utility companies comparable in risk to FPL. This produces an estimate in the range of about 8.9 to 9.4 percent inclusive of a small adjustment (0.1 percent) for flotation expense. As a check, I also conducted a capital asset pricing model (CAPM) study, and using conservative assumptions, I obtained a cost of equity range of 8.63 to 10.25 percent, with a 9.4 percent midpoint. Given this range of study results, I conclude that the cost of equity for FPL at this time is about 9.0 to 9.5 percent, with the preponderance of evidence supporting the lower end of this range.

I do not specifically support (or oppose) the 50 basis point adjustment to ROE proposed in this case to reward the Company for its asserted superior performance since I have not conducted an analysis to determine whether the Company's analysis supporting the superior performance claim is valid. However, as the Company itself acknowledges, this bonus will increase customer rates by about $50 million per year, and this will occur at a time when FPL's retail rates already are quite high relative to those of the benchmark electric utilities employed in this case by the Company (including other major utilities in the Southeast). Consequently, even if the Commission determines that a performance bonus of some amount is warranted, the requested $50 million per year seems extremely large and burdensome to customers.

Rather than recommending (or opposing) a specific performance bonus, I am recommending that the Commission consider a range for the fair ROE to be 9 to 10 percent. The midpoint value of 9.5 percent is the upper end of my DCF cost of equity evidence and is consistent with my CAPM results. As I shall demonstrate, Dr. Avera's analysis -- when corrected -- also falls into or close to this range.

Q. WHY IS YOUR RECOMMENDATION ON RETURN ON EQUITY SO MUCH LOWER THAN DR. AVERA'S COST OF EQUITY ESTIMATES?

A. Dr. Avera and I obtain substantially similar DCF results, with my results being only slightly lower. However, his risk premium/CAPM estimates overstate FPL's cost of equity, most notably because he assumes that investors expect overall, long-term stock market returns in the 12 to 14 percent per year range, returns that are simply are not credible. A further problem is his willingness to use speculative interest rate projections in place of actual market data to develop his risk premium estimates. I also find that his 30 basis points flotation expense adder is excessive.

Q. ARE YOU PROPOSING ANY MODIFICATIONS TO THE PROPOSED FUTURE TEST YEAR CAPITAL STRUCTURE AND COST OF DEBT?

A. I am not proposing a capital structure modification at this time although I am concerned that the proposed 62 percent equity ratio (based on investor-supplier capital) is very expensive and far in excess of what management judges is necessary for the consolidated corporation. I have adjusted FPL's proposed embedded cost of debt downward from 5.89 percent to 5.65 percent to reflect more reasonable assumptions concerning the cost rates for future 2005 and 2006 debt issues. Specifically, FPL has assumed that over the next year it will issue new debt at cost rates of 6.8 to 7.2 percent which is well above current market rates and the Company's recent experience. I have instead assumed a cost rate of 6.0 percent, which is much more realistic although still above current and recent cost rates for FPL.

B. <u>Capital Cost Trends</u>

Q. HAVE YOU REVIEWED THE TRENDS IN MARKET CAPITAL COSTS OVER THE PAST DECADE?

A. Yes. Schedule MIK-2 shows capital cost indicators on an annual basis since 1992 and on a monthly basis from January 2002 to May 2005. This includes inflation (as measured by the annual CPI change), short-term Treasury yields, ten-year Treasury yields and published yields on single A Moody's public utility bonds.

This schedule shows that despite year-to-year fluctuations there is a clear downward trend in capital costs over this time period, particularly for long-term securities. For example, during the early part of this time period utility bonds were yielding around 8 percent, but during the first half of this year utility bond yields were in the 5.6 to 5.8 percent range. There has been a similar decline in yields on the ten-year Treasury notes, from 6 to 7 percent in past years to close to 4 percent in recent months. This declining trend is unmistakable and dramatic, and clearly is a benefit for consumers and businesses (including FPL) making use of credit markets. Long-term interest rates are at historic lows or close to the lowest they have been in several decades.

These very favorable capital cost trends are driven by a number of underlying economic forces. In particular, the recent experience and outlook for inflation has been quite favorable. The rate of inflation over the past year has been 2.8 percent, and absent the volatile food and fuel sectors inflation is a mere 2.2 percent (referred to as "core inflation"). The favorable inflation outlook reflects strong productivity growth and the expansion of global competition (and production capacity) which holds down increases in U.S. product prices.

Q. YOU HAVE DISCUSSED INTEREST RATES ON LONG-TERM SECURITIES. IS THE TREND SIMILAR FOR SHORT-TERM INTEREST RATES?

A. Not entirely. While there is a downward trend over time in short-term interest rates, those rates have begun to move back up in the last two years. This reflects the gradual strengthening of the U.S. economy, and the decision by the Federal Reserve (Fed) to increase short-term interest rates. It is notable that despite the Fed's efforts to increase short-term rates, long-term rates have remained quite low and have not increased.

Q. YOUR SCHEDULE SHOWS THAT LONG-TERM INTEREST RATES ARE QUITE LOW COMPARED TO PAST YEARS. DOES THIS ALSO APPLY TO THE COST OF EQUITY?

A. Yes, I believe so. The underlying factors that have led over time to the very low observed long-term interest rates also favorably affect the cost of equity, and there is no reason to believe this would not apply to FPL as well. There is another force at work that favorably affects the utility cost of equity but does not have a similar beneficial effect on the cost of debt -- federal tax policy. In 2003, Congress enacted tax legislation reducing income tax rates on both capital gains and on common stock dividends. Lower taxes on returns to equity investments mean that investors are willing (or should be willing) to accept lower market returns for holding common stocks, particularly as compared with bonds. I believe that my DCF analysis captures these costs of equity-reducing effects since my analysis incorporates relatively recent stock market data from the time period subsequent to the enactment of that legislation. Certain risk premium methods, particularly those based on historical measures, might not capture that effect.

Q. WHAT IS THE CURRENT TREND AND NEAR-TERM OUTLOOK FOR CAPITAL COSTS?

A. During the past year and a half, capital costs (and inflation) have been very low and declining. Long-term interest rates in 2004 reached a low point in early Spring but then trended up somewhat during the Summer 2004. This upward movement proved to be brief and temporary, and there has been a gradual declining trend since then. For example, the published yield on single A utility bonds (Moody's) has fallen from

6.6 percent in June 2004 to 5.5 percent in May 2005. This downward trend in long-term rates occurred at during the same time period that the Fed was increasing short-term rates.

A discordant note during recent months is that economic forecasters are expecting some degree of reversal of this favorable interest rate trend. According to the Blue Chip Economic Indicators "Consensus" forecast (July 10, 2005), yields on ten-year Treasury notes are projected to increase from current levels of about 4.1 percent to 4.4 percent for calendar 2005 and 4.9 percent for calendar 2006. Inflation, however, is expected to remain under control at 2.5 percent for 2006. This is the average outlook for the approximately 40 forecasting organizations contributing to the Blue Chip survey.

Q. DOES YOUR RECOMMENDATION IN THIS CASE REFLECT THOSE CAPITAL MARKET CONDITIONS?

A. Yes, I believe so. My DCF analysis attempts to use recent stock market data and published investors analyst earnings forecast. Moreover, my ROE recommendation in this case is a range of 9.0 to 10.0 percent, even though current market evidence would support a result closer to the 9.0 percent lower end. Thus, while I employ reasonably current market data, the 9.0 to 10.0 percent range would be valid even if market cost rates move upward, as some analysts predict, as I discuss in the next section of my testimony.

Q. YOUR SCHEDULE MIK-2 INCLUDES YIELDS ON SINGLE A UTILITY BONDS. IS FPL RATED SINGLE A?

A. Yes. FPL is rated strong single A by the major rating agencies, with FPL's first mortgage bonds rated a low double A by Moody's. During the past two years, FPL has been able to issue long-term debt at coupon rates below 6 percent, as I discuss in the next section of my testimony.

C. <u>Testimony Organization</u>

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Section III is a brief discussion of the capital structure and debt cost rate proposed by the Company in this case. I also describe my adjustment to the debt cost rate.

Section IV presents my DCF study, which provides the basis of my recommended ROE in this case. This section also presents my CAPM study which I employ as a check on my DCF results. This helps respond to Dr. Avera's concerns that risk premium-type evidence should be considered along with the DCF analysis.

I present my critique of Dr. Avera's cost of capital studies and his accompanying recommendation in Section V of my testimony. One of my main objections is Dr. Avera's improper use of projected capital costs in place of actual capital costs, which is incorrect and contrary to accepted practice. Also, I explain that his ROE recommendation is not consistent with his own evidence.

The final section of my testimony summarizes my recommended ROE and overall rate of return. In doing so, I discuss the need for an appropriate flotation adjustment and FPL's proposal for an ROE bonus.

III. CAPITAL STRUCTURE/DEBT COST

A. Capital Structure

Q. WHAT CAPITAL STRUCTURE IS FPL PROPOSING IN THIS CASE?

A. The proposed capital structure is a 13-month average for the future test year, 2006. The common equity component is 49.96 percent of total capital, but that is based on including accumulated deferred income taxes, customer deposits and unamortized investment tax credits in capitalization. On the basis of investor-supplied capital, the common equity ratio is approximately 62 percent, which is far above the industry average which approximates 45 percent. (Please note that the average for the electric companies comprising my proxy group is 48 percent, excluding consideration of short-term debt.) The use of a capital structure with an excessive amount of equity can result in customers paying excessive rates since equity carries a higher cost rate than utility debt and its returns are not tax deductible.

I show this capital structure on Schedule MIK-1, page 1 of 1. Please note that the accumulated balance of deferred taxes is included as zero cost capital.

Q. HAS THE COMPANY SOUGHT TO JUSTIFY THE USE OF THIS VERY HIGH EQUITY RATIO?

A. Yes. Dr. Avera states that the very high equity ratio is needed so that FPL can maintain a strong credit rating. This is because at least one of the credit rating agencies (S&P) imputes the long-term purchase power capacity payments to which FPL is contractually obligated as "debt equivalent." He estimates the imputation to be $1.1 billion for the future test year, and recognizing that amount means that FPL has an "equivalent" common equity ratio of 56 percent, which the Company believes to be reasonable for ratemaking. Dr. Avera seems to recognize that the adjusted 56 percent ratio exceeds both the equity ratio of proxy electrics and S&P's capital structure benchmark to retain the single A rating. However, he indicates that there is an industry trend toward maintaining higher equity ratios.

Q. DO YOU AGREE WITH DR. AVERA THAT THE ELECTRIC INDUSTRY IS MOVING TOWARD HIGHER EQUITY RATIOS?

A. Yes. There is at least a mild trend, although it does not support either the 56 percent or 62 percent ratios defended by Dr. Avera. The June 3, 2005 edition of the Value Line Investment Survey (page 156) estimates the industry-wide common equity ratio for 2005 to be 45.0 percent. It also projects that the equity ratio will rise over time to 48.5 percent by 2008-2010. (It is my understanding that these ratios are based on excluding short-term debt from capital structure.) Hence, the FPL 56 or 62 percent figures substantially exceed the industry's capitalization outlook, even accounting for debt imputation.

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING FPL'S CAPITAL STRUCTURE?

A. Yes. There is a substantial difference between the capital structures of FPL utility and FPL Group on a corporate consolidated basis, with FPL having the equity richer capital structure. I show a comparison of the two capital structures (using only investor-supplied capital) on Table 1 below at March 31, 2005 from the recently filed SEC Form 10Q report.

The comparison shows that FPL utility accounts for $10.3 billion of total capital compared to $17.9 billion for FPL Group (about 57 percent). However, the utility accounts for 77 percent of the expensive common equity. In other words, management has allocated a disproportionate amount of the expensive capital to the monopoly utility segment, while the consolidated corporation is capitalized with 45 percent common equity -- typical for the industry. Dr. Avera totally ignores this issue, and it cannot be explained away by "debt imputation" of purchased capacity since that affects both the utility and the consolidated corporation.

TABLE 1

Capital Structure Comparison at March 31, 2005 (millions $)

	FPL Utility		FPL Group	
	balance	**%**	**balance**	**%**
Long-term Debt	$ 2,813	27.4%	$ 8,501	47.4%
Commercial Paper	691	6.7	691	3.9
Current Maturities	496	4.8	636	3.6
Common Equity	6,262	61.0	8,090	45.2
Total	$10,262	100%	$17,918	100%

Source: FPL Group SEC Form 10Q for the quarter ending March 31, 2005.

Q. IN LIGHT OF THIS ISSUE, ARE YOU RECOMMENDING A MODIFICATION TO FPL'S CAPITAL STRUCTURE?

A. No, not at this time. While I am mindful of the need to recognize the net imputation problem, the discrepancy between the FPL and FPL Group capitalization practices cannot be explained by this issue. I believe that FPL should seek to moderate its expensive capital structure over time, and in this case the Commission should take into account the Company's very heavy equity ratio in setting the Company's authorized ROE.

B. FPL's Cost of Debt

Q. WHY HAVE YOU MODIFIED FPL'S DEBT COST RATE?

A. FPL is proposing the use of a 5.89 percent debt cost rate for the future test year. This compares with a debt cost rate of 5.24 percent for the historical 2004 test year. This substantial increase in the cost of debt is proposed because FPL estimates that it will issue over $1 billion of debt (on a 13-month average basis for 2006) at coupon cost rates in the range of 6.8 to 7.2 percent. FPL asserts that these relatively expensive debt issuances will drive up the cost of debt for 2006 as compared to its current cost of debt.

The problem is that the claimed costs of such issuances do not correspond to recent experience. In response to SFHHA Interrogatory 1-1, FPL identified the following recent issuances of 30-year First Mortgage Bonds.

Series	Issue Date	Principal Amount
5.625%	04/03	$500 Million
5.650	01/04	240
5.850	12/02	200
5.950	10/03	300

In addition, on June 2, 2005 the Company announced the sale of $300 million of First Mortgage Bonds at a coupon cost rate of 4.95 percent. In light of this current market data and recent cost of debt experience, it does not appear that FPL's proposal to increase its cost of debt is reasonable.

Q. HOW HAVE YOU MODIFIED FPL'S PROPOSAL?

A. I revised the cost of debt assuming new debt could be issued at an average cost rate of 6.0 percent during 2005 and 2006 rather than 6.8 to 7.2 percent. I regard that assumption as conservatively high compared to recent experience, and even the 6.0 percent would be a significant increase in market rates (an increase that may or may not actually occur). I show the debt cost recalculation on page 2 of Schedule MIK-1, which lowers the cost of debt from 5.89 to 5.65 percent.

Q. WOULD IT BE REASONABLE FOR THE COMMISSION TO CONSIDER AN EVEN LOWER COST OF NEW DEBT?

A. Yes. If the new debt is issued at an average cost rate of 5.6 percent (which is closer to recent experience), this would reduce interest expense by an additional $4 million per year. This would lower my 5.65 percent to 5.55 percent.

IV. THE DCF AND CAPM STUDIES

A. Using the DCF Model

Q. WHAT STANDARD ARE YOU USING TO DEVELOP YOUR RETURN ON EQUITY RECOMMENDATION?

A. As a general matter, the ratemaking process is designed to provide the utility an opportunity to recover its (prudently-incurred) costs of providing utility service to its customers, including the reasonable costs of financing its (used and useful) investment. Consistent with this "cost-based" approach, the fair and appropriate return on equity award for a utility is its cost of equity. The utility's cost of equity is the return required by investors (i.e., the "market return") to acquire or hold that company's common stock. A return award greater than the market return would be excessive and would overcharge consumers for utility service.

Although the concept of cost of equity may be precisely stated, its quantification poses difficulties. The market cost of equity cannot be directly observed (i.e., investors do not directly state their return requirements), and it therefore must be estimated using analytic techniques.

Q. IS THE COST OF EQUITY A FAIR RETURN AWARD?

A. Generally speaking, yes it is. A return award commensurate with the cost of equity provides fair and reasonable compensation to utility investors and normally should allow the utility to successfully finance its operations on reasonable terms.

In this case, FPL has proposed to augment its asserted estimate of its cost of common equity through the use of a 50 basis point performance adder, as discussed in the testimony of Mr. Dewhurst and Dr. Avera. This equates to a revenue burden for FPL customers of $50 million per year. While there may be conceptual merit in rewarding outstanding cost control or service quality performance, I must question the appropriateness of a bonus this large given FPL's relatively high retail rates.

Q. WHAT DETERMINES A COMPANY'S COST OF EQUITY?

A. It should be understood that the cost of equity is essentially a market price, and as such it is determined by the supply and demand forces operating in financial markets. In that regard, there are two key factors that determine this price. First, a company's cost of equity is determined by the fundamental conditions in capital markets (e.g., the outlook for inflation, tightness of monetary policy, investor behavior, etc.). The second factor (or set of factors) is the business and financial risk profile of the company in question. For example, the fact that a utility company operates as a regulated monopoly, dedicated to providing electric service (regarded as an "essential service") typically would imply low business risk and therefore a relatively low cost of equity. FPL's very strong balance sheet also contributes to its relatively low cost of equity.

Q. DOES DR. AVERA'S TESTIMONY REFLECT THESE PRINCIPLES?

A. Yes, he incorporates these principles in conducting his DCF analysis. However, his risk premium studies do not fully recognize FPL's low risk, nor does his decision to base his ROE recommendation on results exceeding much of his cost of equity evidence.

Q. WHAT METHODS ARE YOU USING IN THIS CASE?

A. I have employed the standard discounted cash flow (DCF) model, which I describe in this section, and the capital asset pricing model (CAPM), which I describe later in this section. I apply both models to a group of proxy electric utility companies comparable in risk to FPL.

The DCF model is one of the approaches employed by Dr. Avera, and based on my experience, is the cost of equity method most widely relied upon by state and federal regulatory commissions, including this Commission. Its widespread acceptance is due to the fact that the model is market-based and is derived from standard financial theory. The theory begins by recognizing that any publicly-traded common stock (utility or otherwise) will sell at a price reflecting the discounted stream of cash flows expected by investors. The objective is to estimate that discount rate.

Using certain simplifying assumptions, the DCF model for dividend paying stocks can be distilled to the following formula:

$K_e = D_o/P_o\,(1 + 0.5g) + g$, where:

K_e = cost of equity;

D_o = the current annualized dividend;

P_o = the stock price; and

g = the long-term dividend growth rate.

This is referred to as the constant growth model, because for mathematical simplicity, it is assumed that the growth rate is constant for an indefinitely long time period. While this assumption may be unrealistic in many cases, for traditional utilities (which typically are far more stable than unregulated companies) the assumption may be reasonable, particularly when applied to a group of companies.

Q. HOW HAVE YOU APPLIED THIS MODEL?

A. Strictly speaking, the model can be applied only to publicly-traded companies, i.e., companies whose market prices (and hence valuations) are transparently revealed.

Consequently, the model cannot be <u>directly</u> applied to FPL, and therefore a market "proxy" is needed. In theory, the model can be applied to FPL Group, FPL's corporate parent, and I have done so by including FPL Group in my group of proxy electric companies.

I believe that a (properly selected) proxy group study is likely to be more reliable than a single company study. This is because there is "noise" or fluctuations in stock price (or other) data that cannot always be readily accounted for in a simple DCF study. The use of an appropriate proxy group helps to allow such "data anomalies" cancel out in the averaging process. For the same reason, I prefer to use market data averaged over a period of several months (i.e., six months) rather than "spot" data.

B. <u>DCF Study Using the Proxy Group of Electric Utility Companies</u>

Q. PLEASE DESCRIBE YOUR ELECTRIC UTILITY PROXY GROUP.

A. For cost of equity purposes, I have selected eleven electric utility holding companies operating in the East and Central regions of the U.S. The eleven companies include:

- Ameren Corp.
- Entergy Corporation
- FPL Group
- Great Plains Energy
- Progress Energy
- SCANA Corp.
- Southern Co.

! Vectren

$ WPS Resources Corp.

$ Westar Energy

$ Wisconsin Energy

I list these companies on Schedule MIK-3, along with certain risk or financial indicators.

Q. HOW DID YOU SELECT THIS PROXY GROUP?

A. This proxy group is derived from the Value Line data base for the Eastern and Central region electric utility companies. Starting with these two regional groups, I eliminated companies for the following reasons:

- Value Line Safety Rating higher than "2" (i.e., only "1" and "2" retained)

- Companies with substantial utility operations in retail access states were eliminated (i.e., virtually all Mid-Atlantic states, Northeast states, Ohio, Illinois, Texas, Michigan).

- Utility companies classified as "small cap" stocks.

- Companies not paying dividends.

In addition, I eliminated one other company that otherwise could qualify, Allete, Inc., due to that company's substantial non-regulated operations and recent corporate restructuring. I note that Dr. Avera similarly disqualified this company from his proxy group.

Q. IN TERMS OF INVESTMENT RISK, HOW DOES THIS GROUP COMPARE TO FPL?

A. Based on the information on Schedule MIK-3, it appears that FPL (or FPL Group) is similar to or less risky than the proxy group. The group average equity ratio is 48 percent compared with FPL's proposed 62 percent (or 56 percent adjusted for debt imputation). FPL Group's Safety Rating is "1" (the highest rating) compared to a group average 1.7, and FPL Group enjoys a Financial Strength rating of A+ (the proxy group's highest rating).

Dr. Avera discussed nuclear power generation in his testimony as an important risk factor, although recently, nuclear generation has become looked at by investors more favorably than in years past. However, ten of the eleven proxy companies in my group have nuclear generation in their supply mixes.

Q. HOW HAVE YOU APPLIED THE DCF MODEL TO THIS GROUP?

A. I have elected to use a six-month time period to measure the dividend yield component (Do/Po) of the equation. Using the Standard & Poors Stock Guide, I compiled month ending dividend yields for the six months ending May 2005, the most recent data available to me as of this writing. Hence, my market data cover essentially the first half of calendar 2005.

I show these dividend yield data on page 1 of Schedule MIK-4. Over the six month time period, the dividend yields for the eleven companies ranged from 4.25 in March to 4.05 percent in May, indicating a very slight downward trend over the recent six-month period, with a six-month average for the proxy group of 4.17 percent.

For DCF purposes, I am relying on the 4.17 percent proxy group six-month average.

Q. IS 4.17 PERCENT THE FINAL DIVIDEND YIELD?

A. Not quite. Strictly speaking, the dividend yield used in the model should be the value that the investor expects over the next 12 months. Using the standard "half-year" growth rate adjustment technique (which I assume to be 2.5 percent), the DCF adjusted yield is 4.3 percent (4.17 x 1.025).

Q. HOW HAVE YOU DEVELOPED YOUR GROWTH RATE COMPONENT?

A. Unlike the dividend yield, the investor-expected growth rate cannot be directly observed but instead must be inferred through a review of available evidence. The growth rate in question is the <u>long-term</u> dividend growth rate, but analysts frequently use earnings growth as a proxy for (long-term) dividend growth. This is because in the long run earnings are the ultimate source of dividend payments to shareholders, and dividend growth cannot exceed earnings growth over a long time period -- particularly for a group of companies.

One possible approach is to examine historical growth as a guide to investor expected growth, for example the recent five-year growth rates for earnings, dividends and book value. However, my experience with electric companies has been that these historic measures have become quite volatile in recent years and therefore provide little (or questionable) useful guidance concerning expected long-term growth trends. This is illustrated on Schedule MIK-5, page 4 of 4. The observed volatility in these financial measures is not surprising given the electric utility industry's extensive corporate and regulatory restructuring activities during the past five years. I note that Dr. Avera similarly considers but then rejects the use of the recent historical growth rates for DCF purposes.

Q. WHAT EVIDENCE, OTHER THAN HISTORICAL TRENDS, HAVE YOU REVIEWED?

A. The DCF growth rate should be prospective, and one particularly useful source of information on prospective growth is the projections of earnings per share (typically five years) prepared by securities analysts. In fact, Dr. Avera appears to give substantial weight to this information in conducting his DCF study. There are several publicly available sources of projected earnings prepared by securities analysts.

Schedule MIK-5, page 2 of 4, presents four well-known sources of projected earnings growth rates. Three of the four sources – First Call, Zacks and Standard & Poors (S&P) – provide averages from securities analyst surveys (typically the median value). The fourth, Value Line, is that organization's own estimates. Value Line publishes its estimate of five-year earnings growth using the average annual earnings during 2001 to 2003 to 2008-2010 for growth rate calculation purposes. As this schedule shows, the projected growth rates calculated in this manner tend to be very unstable. Consequently, I also calculate the five-year growth rate using Value Line's projection for 2009 versus a 2004 base year. These various sources appear to support an expected earnings growth range of about 4.5 to 5.0 percent. The three analyst surveys indicate five-year earnings growth rates for the group of 4.5, 4.6 and 4.9 percent -- supporting the 4.5 to 5.0 percent range.

Q. IS THERE OTHER GROWTH RATE EVIDENCE THAT SHOULD BE CONSIDERED IN ADDITION TO SECURITY ANALYST EARNINGS PROJECTIONS?

A. Yes. There are a number of reasons why investor expectations of <u>long run</u> growth could differ from the limited, five-year earnings projections from securities analysts. Consequently, while securities analyst estimates should be considered and given substantial weight, these growth rates should be subject to a reasonableness test and corroboration, to the extent feasible.

On Schedule MIK-5, page 3 of 4, I have compiled Value Line five-year growth rate projections of dividends, book value and retained earnings (the latter for the outyears 2008 to 2010) for each of the proxy companies. (Retained earnings growth measures the growth over time that one would expect from the reinvestment of earnings, i.e., earnings not paid as dividends.) As this schedule shows, Value Line figures tend to be somewhat less stable than the analyst surveys. However, these four measures support a range of 4.0 to 5.3 percent, which is at least roughly in line with my finding of 4.5 to 5.0 percent and even suggests that this range is conservatively high.

Q. WHAT IS YOUR DCF CONCLUSION?

A. I summarize my DCF analysis on page 1 of Schedule MIK-5. The adjusted dividend yield for the first half of 2005 for this proxy group is 4.3 percent. Available evidence would suggest a DCF growth range of about 4.5 to 5.0 percent (considering both Value Line projections and surveys of securities analyst earnings growth rates). This produces an investor total return of 8.8 to 9.3 percent, with a midpoint of 9.05 percent.

Q. DO YOU INCLUDE AN ADJUSTMENT FOR FLOTATION EXPENSE?

A. Yes. As discussed in the final section of my testimony, I include an adjustment for flotation expense of 0.1 percent. It is my understanding that this Commission permits such an adjustment, and in this case FPL Group undertook a public issuance of common stock issuance earlier this year of $575 million.

With an equity flotation expense adjustment the final DCF cost of equity becomes 8.9 to 9.4 percent, with a midpoint of 9.15 percent. As discussed in the final section of my testimony, I recommend that the Commission give consideration to an ROE range of 9.0 to 10.0 percent which is somewhat higher than my pure DCF results.

Q. DID YOU CONDUCT A DCF STUDY USING DR. AVERA'S PROXY COMPANIES?

A. No, I did not. Dr. Avera obtained a DCF result of 9.4 percent using data sources and methods generally similar to what I used. Since his 9.4 percent result falls within the range of my ROE recommendation, I see little reason to conduct a further DCF study using his proxy companies.

C. <u>The CAPM Analysis</u>

Q. PLEASE DESCRIBE THE CAPM MODEL.

A. The CAPM is a form of the "risk premium" approach and is based on modern portfolio theory. Based on my experience, the CAPM is the cost of equity method most often used in rate cases after the DCF method, and it is one of Dr. Avera's four methods.

According to this model, the cost of equity (Ke) is equal to the yield on a risk-free asset plus on equity risk premium multiplied by a firm's "beta" statistic. "Beta" is a firm-specific risk measure which is computed as the movements in a company's stock price (or market return) relative to contemporaneous movements in the broadly defined stock market. This measures the investment risk that cannot be reduced or eliminated through asset diversification (i.e., holding a broad portfolio of assets). The overall market, by definition, has a beta of 1.0, and a company with lower than average investment risk (e.g., a utility company) would have a beta below 1.0. The "risk premium" is defined as the expected return on the overall stock market minus the yield or return on a risk free asset.

The CAPM formula is:

K_e = $R_f + \beta\ (R_m - R_f)$, where:

K_e = the firm's cost of equity
R_m = the expected return on the overall market
R_f = the yield on the risk free asset
β = the firm (or group of firms) risk measure.

Two of the three principal variables in the model are directly observable -- the yield on a risk-free asset (e.g., a Treasury security yield) and the beta. For example, Value Line publishes betas for each of the companies that it covers. The difficulty, however, is in the measurement of the expected stock market return (and therefore the risk premium), since that variable cannot be directly observed.

Q. HOW HAVE YOU APPLIED THIS MODEL?

A. For purposes of my CAPM analysis, I have used a long-term (i.e., 20 year) Treasury yield as the risk free return and the average beta for the eleven proxy group companies. (See Schedule MIK-3 for the company-by-company betas.) In recent months, long-term Treasury yields have been approximately in the range of 4.5 to 5.0 percent, and the beta for the proxy group averages 0.75. Finally, and as explained below, I am using a stock market return estimate of 10 to 12 percent, although I see little support for the upper end of that range.

Using these data inputs, the CAPM results are shown on page 1 of Schedule MIK-6. My low-end estimate uses a risk-free rate of 4.5 percent and a stock market return of 10.0 percent:

$$K_e = 4.5\% + 0.75\ (10.0\% - 4.5\%) = 8.63\%$$

The upper end uses a risk-free rate of 5.0 percent and a stock market return of 12.0 percent.

$$Ke = 5.0 + 0.75\ (12\% - 5.0\%) = 10.25\%$$

Thus, with these inputs the CAPM provides a return range of 8.63 to 10.25 percent, with a midpoint of 9.44 percent. The CAPM analysis produces results slightly higher than the midpoint result than my DCF analysis, and I have factored this into the ROE range that I have identified for FPL. That is, the midpoint of 9.44 percent is well within my recommended 9.0 to 10.0 percent range.

Q. IT APPEARS THAT A KEY ELEMENT IN YOUR CAPM IS YOUR MARKET RETURN RANGE OF 10 TO 12 PERCENT. HOW DID YOU DERIVE THAT RANGE?

A. Various measures of market return (and therefore the equity risk premium) are shown on page 2 of Schedule MIK-6. These market returns average to about 11.0 percent, and therefore the various equity risk premium measures average about 6.2 percent, if one assumes a prospective risk-free return of 4.75 percent.

Q. PLEASE DESCRIBE THESE MEASURES.

A. In general, two approaches have been used to obtain either the risk premium or the market return required by the CAPM. The first is to perform a DCF calculation on the overall stock market, and the second approach makes use of historical expected returns data measured over a long time period. Dr. Avera adopts the first method in his CAPM analysis, which leads him to conclude (erroneously) that the equity risk premium (relative to a long-term Treasury bond yield) is approximately 9 percent.

Q. HAVE YOU PERFORMED A STOCK MARKET TOTAL RETURNS ANALYSIS?

A. Yes. Value Line publishes projections for its "Industrial Composite" twice each year, and that information can be used to perform a DCF total return calculation. As of April 2005, Value Line was projecting five-year earnings growth of 7.0 percent and long-term growth from retained earnings of 11.0 percent. Averaging the two measures provides a composite growth rate of 9.0 percent. When combined with Value Line's reported dividend yield of 1.9 percent for the Industrial Composite, the total return is 10.9 percent. The Industrial Composite is a broad measure of the overall stock market, excluding only utilities, financial services and non-North American companies.

Q. WHAT ARE THE HISTORICAL RISK PREMIUM VALUES?

A. Cost of equity analysts frequently cite to historic returns data compiled by Ibbotson Associates, and I have used that source as well. Based on historic (1926-2003) after-the-fact returns published by the Ibbotson in 2004, the stock market risk premium relative to long-term Treasury bonds averages 6.6 percent. Combining that value with recent long-term Treasury yields of about 4.75 percent provides a market return of 11.35 percent. Dr. Avera also employs the long-term historical risk premium from Ibbotson but cites a somewhat higher figure, 7.2 percent.

There are reasons, however, for believing that even the 6.6 percent historical premium is too high. A recent research study by Ibbotson and Chen, estimates a long-term (arithmetic) historic risk premium of 5.9 percent. The authors estimate this figure using a supply-side model removing the effects of a rising P/E ratio over the historical period. This analysis acknowledges that the historical trend of rising P/Es served to inflate the achieved historical returns and such an increase would not be expected to continue indefinitely into the future. Combining the Ibbotson/Chen 5.9 percent risk premium with a current long-term Treasury yield of 4.75 percent produces an overall stock market return of 10.65 percent.[1] I would note that Ibbotson/Chen also report a geometric average risk premium of about 4 percent.

Q. PLEASE SUMMARIZE THE MARKET RETURN EVIDENCE.

A. These four measures of overall stock market return range from 10.65 to 11.35 percent, validating the assumed range used in my CAPM study on page 1 of Schedule MIK-6 of 10 to 12 percent. These stock market return estimates imply a (midpoint) stock market risk premium (relative to long-term Treasury bonds) of about 6.2 percent.

It should be noted that my CAPM study results in certain respects are conservatively high, even though my cost of equity estimate is significantly lower than that of Dr. Avera (i.e., 11.8 percent). This is because I have employed the yield on long-term Treasury bonds as the "risk free return," when, in fact, Treasury bonds clearly are not risk free. Investors are well aware of the "interest rate risk" associated with Treasury bonds (i.e., bond prices will fall if interest rates rise). Moreover, I have made use of "arithmetic" historic average returns, even though investors are undoubtedly aware of both arithmetic and geometric averages. The geometric historic returns are somewhat lower than the arithmetic returns, as I show on page 2 of Schedule MIK-6. Providing some recognition of the geometric historic averages, along with the arithmetic historic average, would be reasonable and would lower the CAPM-derived cost of equity that I have presented.

Since my analysis incorporates both long-term Treasury yields and arithmetic historic returns, the CAPM results should be viewed as conservatively high estimates

[1] Roger G. Ibbotson and Peng Chen, "Stock Market Returns in the Long Run: Participating in the Real Economy," Financial Analyst Journal (forthcoming).

of the cost of equity. Hence, greater weight should be given to the lower end of my CAPM range, i.e., the 8.6 to 9.4 percent portion of my range.

IV. DR. AVERA'S ROE ANALYSIS

Q. HOW DID MR. AVERA OBTAIN HIS 12.3 PERCENT ROE RECOMMENDATION?

A. Dr. Avera performs a DCF analysis and three variants of the risk premium method (using both current debt cost rates and 2006 projected debt cost rates). One of the three risk premium variants is the CAPM, as discussed in the previous section, and to develop the stock market return component he uses both historical data and projections. The use of projected interest rates in his risk premium studies appears to add nearly a full percent point to his cost of equity study estimates. Notably, Dr. Avera does not factor in the assumption of increases in market capital costs in his DCF study. Dr. Avera characterizes these cost of equity results as falling in a range of 10.0 to 12.0 percent, which would seem to imply a midpoint of about 11.0 percent.

Dr. Avera then proceeds to raise these results by making the following three adjustments.

- He discards the lower half of his range and selects 11 to 12 percent instead of 10 to 12 percent due to FPL's "risk exposure" (a midpoint of 11.5 percent).
- He adds 0.3 percent for flotation expense, producing a midpoint cost of equity of 11.8 percent.
- He incorporates Mr. Dewhurst's performance bonus of 0.5 percent, to obtain a final 12.3 percent ROE award.

Q. DO YOU AGREE THAT HIS COST OF EQUITY STUDY ESTIMATES PRODUCE A RANGE OF 10 TO 12 PERCENT AND A MIDPOINT OF 11.0 PERCENT FOR FPL?

A. No. This range is obtained only by giving little weight to the DCF study (9.4 percent) and by the inclusion of projections of rising interest rates. The latter is highly improper and inconsistent with accepted cost of capital practice. For example, if one takes his cost of equity studies and (a) allocates a 50 percent weight to DCF and 50 percent weight to risk premium; and (b) includes risk premium studies that use only actual and not projected market interest rates, the following would result.

TABLE 2

Dr. Avera Cost of Equity Results

Risk Premium (using actual cost of debt)	
(1) Authorized returns	10.6%
(2) Realized Returns	9.7
(3) CAPM Projected	11.8
(4) CAPM Historical	10.1
Average	10.55%
DCF Analysis	9.4%
Cost of Equity Average	**9.98%**

Source: Document WEA-11, page 1 of 1

Dr. Avera's results seem to support a cost of equity average of about 10.0 percent, although his projected return CAPM at 11.8 percent seems to be an outlier.

Q. IS DR. AVERA JUSTIFIED IN INCLUDING AN ADJUSTMENT FOR FLOTATION EXPENSE?

A. Yes, although I believe that 0.3 percent is too high. As I explain in the next section, I believe 0.1 percent would be reasonable compensation for FPL for flotation expense.

Q. WHY SHOULD THE COST OF CAPITAL STUDIES BASED ON PROJECTED RATHER THAN ACTUAL LONG-TERM INTEREST RATES BE REJECTED?

A. This is contrary to standard practice in performing cost of capital studies, and to his credit, Dr. Avera did not attempt to introduce assumptions about rising capital costs in his DCF study. The use of projected in place of actual long-term interest rates is a clear rejection of market price information and in doing so is contrary to accepted financial theory. Dr. Avera, in essence, is saying "markets are wrong," and they are pricing debt securities improperly.

Q. ARE YOU SAYING THAT FINANCIAL MARKETS ARE NOT ASSUMING THE LARGE INTEREST RATE INCREASES ON LONG-TERM BONDS IN 2006 THAT DR. AVERAGE HAS USED?

A. Yes. For example, Dr. Avera states that long-term Treasury bonds currently yield 4.6 percent, but he assumes a 2006 value of 5.8 percent, or 120 basis points higher. His current figure of 4.6 percent is within my range of 4.5 to 5.0 percent. An increase in Treasury bond yields to 5.8 percent would imply a huge drop in the prices of long-term Treasury bonds over the next year. While some investors may expect such a decline, it is obvious that preponderance of investors do not. No rational investor would hold a long-term Treasury bond if he expects (for example) a 20 percent price drop to occur over the next year. Rather, the investor's rational strategy would be to hold a short-term Treasury security, accept a slightly lower yield for one year, and wait for the price of Treasury bonds to fall. The rational investor would then purchase the bond at its much lower price. This behavior serves to arbitrage away the difference between current and expected prices (and interest rates) on long-term securities.

Dr. Avera's use of projected rather than actual long-term interest rates improperly assumes irrational behavior on the part of financial markets. This would be no different than if Dr. Avera had decided that the stock prices in his DCF study were too high and must be reduced by 20 percent.

Q. ARE YOU SAYING THAT FORECASTS MUST BE IGNORED?

A. No, I am not saying that. What I am saying is that cost of equity studies should be based on relatively current market price data, not hypothetical market prices that may or may not occur in the future. The forecasts that Dr. Avera relies upon are information readily available to investors and therefore priced in to securities already. However, the credible cost of equity evidence will provide the Commission with a range of results to consider. Within that range that Commission may wish to consider recent cost of capital trends, interest rate projections and other factors in selecting a final ROE award for FPL.

Q. WHAT IS YOUR DISAGREEMENT WITH DR. AVERA'S CAPM ANALYSIS?

A. Setting aside the interest rate projections issue, my only disagreement is with the risk premium/market return values used in his CAPM calculations. He utilizes an historical Ibbotson risk premium value of 7.2 percent and a projected stock market risk premium of 9.3 percent. The latter is based upon his estimates of a long-run annualized return on the stock market (i.e., the S&P 500) of about 14 percent. Both of these estimates are unreasonably high.

Dr. Avera apparently obtained the 7.2 percent figure from Ibbotson's 2004 Yearbook based on the difference between stock market and Treasury bonds returns over the historical period. However, as I show on my Schedule MIK-6, page 2, Ibbotson actually reports a risk premium of stocks over Treasury bonds of 6.6

percent, not 7.2 percent. This is based upon the difference between the historical average return on Large Company Stocks (12.4 percent) versus the historical average return on Long-term Government Bonds (5.8 percent) (Ibbotson, Stocks Bonds, Bills and Inflation, 2004, Table 4 "Summary Statistics of Annual Returns"). However, even the 6.6 percent is biased upwards by the increase over the historical period in price/earnings ratios, an increase that would not be expected to persist over time.

Ibbotson's recent study with Dr. Chen (cited in the last section of my testimony) develops a more realistic 5.9 percent (arithmetic) risk premium based upon their use of a supply side model. In explaining their derivation of the 5.9 percent equity risk premium, the authors make the following salient point:

> Supply side models can be used to forecast the long-run expected equity return. The supply of stock market returns is generated by the productivity of the corporations in the real economy. Over the long run, the equity return should be close to the long run supply estimate. In other words, investors should not expect a much higher or a much lower return than that produced by companies in the real economy. We believe the investors' expectations on the long-term equity performance should be based on the supply of equity returns produced by corporations. (Ibbotson and Chen, page 11)

Clearly, the Ibbotson/Chen 5.9 percent equity risk premium is linked -- properly

Q. SO -- TO THE PRODUCTIVITY OF THE U.S. ECONOMY. THIS IS SIGNIFICANTLY LOWER THAN BOTH THE REPORTED 6.6 PERCENT HISTORICAL VALUE AND DR. AVERA'S 7.2 PERCENT.

HOW DID DR. AVERA DERIVE HIS 9.3 PERCENT RISK PREMIUM ESTIMATE?

A. This is derived from his estimate of a 13.9 percent stock market long-run annualized return, which itself is based on earnings growth of 12.1 percent and a dividend yield of 1.8 percent.

Q. DO YOU BELIEVE INVESTORS EXPECT LONG-RUN EARNINGS GROWTH OF 12.1 PERCENT FOR THE S&P 500?

A. No, Dr. Avera's 12.1 percent earnings growth rate and 13.9 percent return on stocks are completely unrealistic, as demonstrated by the Ibbotson and Chen study. The historical and forecasted growth in nominal GDP (the overall U.S. economy) is about 6 percent (or slightly less), and hence the 12.1 percent earnings growth rate is more than double the growth rate of the U.S. economy. Growth of 12.1 percent per year on a long-run basis simply is not sustainable. Hence, even if investors were expecting 12 percent earnings growth for a period of several years, it is likely that they would anticipate some slow down thereafter.

I have also consulted other sources of projections for stock market earnings, and they are considerably less than Dr. Avera's very optimistic 12.1 percent. The Zacks survey projects five years earnings growth for the S&P 500 of 6.0 percent, while First Call projects five-year growth of 10.5 percent. Value Line projects five-year earnings growth for its broad industry growth (the "Industrial Composite") of 7 percent. Averaging these three sources produces a stock market earnings growth rate of about 8 percent (and therefore a stock market return of about 10 percent), which is far more realistic than Dr. Avera's 12.1 percent.

Q. WHAT DO YOU CONCLUDE REGARDING THE CAPM?

A. The majority of the evidence supports an equity risk premium for the overall market of about 6 percent, not the unrealistically high 7.2 or 9.3 percent used by Dr. Avera. Had Dr. Avera used that risk premium value, he would have obtained a CAPM result in the 9.0 to 9.5 percent range, consistent with my study.

Q. DR. AVERA PRESENTED AN AUTHORIZED RETURNS RISK PREMIUM ANALYSIS. PLEASE DESCRIBE THAT ANALYSIS.

A. This method observes authorized electric utility ROEs going back to the 1970s and calculates the implied risk premium (relative to utility bonds) each year. He then estimates a regression model that relates this risk premium to the contemporaneous level of interest rates, finding an inverse relationship. Dr. Avera uses the model to obtain a 10.6 percent cost of equity for 2005, assuming a current utility bond yield is 5.8 percent. However, since FPL's cost of debt at this time is probably somewhat lower than 5.8 percent, the 10.6 percent is somewhat overstated.

Q. IS THIS A REASONABLE WAY TO ESTIMATE THE COST OF EQUITY?

A. No, it is not. The first problem is that these historical ROEs are not the same thing as the cost of equity and therefore the model does not measure a risk premium -- at least not very well. The problem is that the authorized ROEs include a number of factors in addition to the regulators' cost of equity estimate -- flotation adders, performance bonuses, rate case settlement results (which typically are based on numerous factors), adjustments to address financial need, etc. For all of these reasons the authorized ROEs can differ significantly from the regulators' estimates of the utility cost of equity. It is likely that the authorized ROEs (and therefore risk premiums) reported by Dr. Avera may take into account some of the same adjustment factors embodied in developing his 12.3 percent recommendation in this case.

The regression model estimated by Dr. Avera finds an inverse relationship with interest rates, i.e., the equity risk premium rises as the interest rate falls. However, this result, if anything, is an observation on the behavior of the regulatory process rather than the requirements of financial markets. It merely indicates -- for better or for worse -- that there is a certain amount of inertia or regulatory lag in the rate setting and ROE award process. Specifically, over the time period of Dr. Avera's data base, the 1970s to 2004, there was a general declining trend in interest rates. Regulators lowered utility ROEs in response, but with a lag and not in lock step. Hence, the model illustrates and measures regulatory behavior, not the requirements of financial markets. While I find Dr. Avera's analysis provides insight into regulation, it cannot be considered to be a particularly useful cost of equity estimation method.

Q. DOES THIS MODEL OVERSTATE FPL'S COST OF EQUITY?

A. Yes, it does for several reasons. First, Dr. Avera used a "current" 5.8 percent debt cost rate, which probably overstates FPL's current cost of debt. Second, the risk premium values themselves likely embody a great many factors that influence ROE awards <u>in addition to</u> the pure cost of equity. Since Dr. Avera later proposes his own adders (i.e., flotation, "financial exposure," performance bonuses), he may have introduced a double counting problem with this analysis.

V. **RECOMMENDATION ON ROE**

Q. WHAT IS YOUR RECOMMENDATION ON THE AUTHORIZED ROE?

A. In this case, I have obtained a midpoint DCF of 9.15 percent and a midpoint CAPM of 9.4 percent. Hence, the bare bones cost of equity results support an award in the 9.0 to 9.5 percent range. However, there are a number of other factors raised in this case that the Commission may wish to consider that would somewhat expand the range. These have been discussed in my testimony and that of the Company witnesses.

- Inclusion of an allowance for flotation expense.
- FPL's unusually strong and expensive capital structure, as well as its very strong credit rating and favorable risk attributes.
- Projections of increases in capital costs.
- The request for a performance bonus.

Depending on the Commission's evaluation of these issues, any return in the range of 9.0 to 10.0 percent could be considered reasonable. For revenue deficiency purposes in this rate case, I have selected the midpoint of this range, i.e., 9.5 percent. However, I am not making a specific recommendation on the appropriate magnitude (if any) of a performance bonus.

Q. HOW HAVE YOU DEVELOPED YOUR FLOTATION ALLOWANCE OF 0.1 PERCENT?

A. Dr. Avera recommends an adjustment of 0.3 percent which appears to be based on the assumption that flotation expenses are 5 to 10 percent of stock issuance proceeds. This adjustment will cost ratepayers about $30 million per year, and I believe this to be excessive. A more realistic expense ratio (which mostly is to cover underwriter fees) would be 3 percent. It appears that a 3 percent value was accepted by this Commission in the recent Gulf Power Company case, Docket No. 010949-EI (June 10, 2002). Using my proxy group dividend yield of 4.17 percent, the 3 percent figure would add 13 basis points, i.e., an increase to the ROE of about 0.1 percent.

The flotation allowance is also reasonable since FPL Group conducted a $575 million stock issuance this year. If the cost incurred is 3 percent of the proceeds, this would imply a total cost of flotation of about $17 million. However, a major public issuance of common stock does not occur every year. Only two such issuances have occurred since January 2001 (response to Interrogatory 1-1 of SFHHA), and thus a two- or three-year amortization of that flotation cost would be appropriate for ratemaking purposes. Assuming a two-year amortization (i.e., roughly $8 million per year) and an FPL Group equity balance of about $8 billion, an equity return flotation adjustment of 0.1 percent (i.e., $8 million/$8 billion) would provide appropriate cost recovery.

Q. ARE THERE ANY REASONS WHY THE FLOTATION ADJUSTMENT SHOULD NOT EXCEED 0.1 PERCENT?

A. Yes. It appears that the need to issue new common stock is to a large degree driven by the unregulated side of FPL Group. Data supplied to Staff indicates that the utility segment pays out to its parent far more than what FPL Group actually pays to its common stock holders, as shown below:

TABLE 3

Dividend Payments, 1999-2004
(millions $)

	FPL to Group	Group to Investors
1999	$ 586	$335
2000	667	366
2001	667	377
2002	NA	400
2003	1,127	425
2004	603	467

Source: Response to Staff, Set 1, items 60 and 61.

Q. MR. DEWHURST PROPOSES A 50 BASIS POINT PERFORMANCE BONUS IN THIS CASE. WHAT IS THE BASIS FOR THIS REQUEST?

A. Mr. Dewhurst presents data indicating that FPL has incurred lower O&M and gross plant costs per kWh of sales than has a benchmark group of electric utilities selected by the Company for study purposes. (See Document No. MPD-1.)

Q. DO YOU AGREE WITH HIS ANALYSIS?

A. Mr. Dewhurst attempts to demonstrate that FPL's cost control efforts have provided customers with savings and the achievement of the savings warrants a $50 million per year profit bonus to be paid by retail customers. Given the schedule in this case, I have not had the opportunity to conduct an analysis of the Company's performance claims, and therefore I am not specifically supporting or opposing his analysis.

I do, however, believe there is merit in examining the proposed $50 million bonus in its proper context. In addition to the O&M/gross plant cost savings identified by Mr. Dewhurst, it is useful to compare FPL's retail rates (which comprehensively measure the total cost of service) to those of the Peer Group companies selected for the Company's benchmark study. Schedule MIK-7, page 1, shows this comparison for FPL and each of the peer electric utilities, and page 2 shows the comparison for other major electric utilities in the Southeast (SERC) region of the U.S. Both comparisons indicate that FPL's residential retail rates are well above average.

Q. WHAT IS THE SIGNIFICANCE OF THE RATES COMPARISON?

A. The retail rates comparison, which is adverse to FPL, indicates that it is difficult to reach firm overall conclusions over cost control/management efficiency performance. This comparison may indicate that O&M/gross plant is too narrow of a measure, or it also is possible that FPL may be subject to certain cost pressures that are not as prevalent for the other electric utilities.

It seems incongruous to award a large performance bonus -- which would further increases retail rates -- when customers are already burdened by rates that are well above average. In any event, I would urge the Commission to take into account these rates comparisons along with Mr. Dewhurst's analysis when determining whether a performance bonus in this case is warranted. When considering the request for a large performance bonus for shareholders, I believe it is important to consider the impact this award will have on retail customers and whether an award provides an appropriate balance of interests.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

STATE OF FLORIDA

BEFORE THE

PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE)
BY FLORIDA POWER & LIGHT COMPANY) Docket No. 050045-EI

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY OF

MATTHEW I. KAHAL

ON BEHALF OF THE

FEDERAL EXECUTIVE AGENCIES

JUNE 2005

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

Docket No. 050045-EI
Kahal Exhibit No. __
Schedule MIK-1

Rate of Return Summary

FLORIDA POWER & LIGHT COMPANY

Overall Rate of Return Summary
Based on Company-Projected Capital Structure

Capital Type	Ratio	Cost Rate	Weighted Cost
Long-Term Debt	30.23%	5.65%	1.71%
Preferred Stock	0.00	--	--
Customer Deposits	3.52	5.98	0.21
Common Equity	49.96	9.5	4.75
Short-Term Debt	0.50	8.73	0.04
Deferred Taxes	15.40	0.00	0.00
Investment Tax Credits	0.40	8.05	0.03
Total	**100.0%**	**--**	**6.74%**

Source: MFR Schedule D-1(a), except for cost of long-term debt (Schedule MIK-1, page 2 of 2) and return on equity (Schedule MIK-5, page 1 of 4)

Note: The capital structure shown above is for presentation purposes and should not be interpreted as an endorsement.

Docket No. 050045-EI
Kahal Exhibit No. __
Schedule MIK-1
Page 2 of 2
Rate of Return Summary

FLORIDA POWER & LIGHT COMPANY

Adjustment to the Cost of Debt
For Future Test Year
($000s)

Projected New Debt Per FP&L

Cost Rate	Issue Date	Average Balance	Interest Expense	Revised Interest Expense*	Change in Interest Expense
6.8%	Dec '05	$ 400,000	$ 27,200	$ 24,000	($ 3,200)
6.8%	Oct '05	400,000	27,200	24,000	(3,200)
7.2%	Mar '06	230,769	18,000	15,000	(3,000)
7.2%	Dec '06	23,077	1,800	1,500	(300)
Total					**($ 9,500)**

Calculation of Embedded Cost of Debt

	Annual Cost	Adjustment	Revised Annual Cost	Debt Balance	Cost Rate
Per FP&L	$ 234,345	--	$ 234,345	$ 3,976,970	5.89%
As Revised	$ 234,345	(9,500)	$ 224,845	$ 3,976,970	5.65%

Source: MFR Schedule D-4(a)

*Revised interest expense is based on using a more realistic 6.0% debt cost rate in place of the 6.8 to 7.2% figure assumed by FP&L.

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Schedule MIK-2
Page 1 of 3
Trends in Capital Costs

FLORIDA POWER & LIGHT COMPANY

Trends in Capital Costs

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield
1992	3.0%	7.0%	3.5%	8.7%
1993	3.0	5.9	3.0	7.6
1994	2.6	7.1	4.3	8.3
1995	2.8	6.6	5.5	7.9
1996	3.0	6.4	5.0	7.8
1997	2.3	6.4	5.1	7.6
1998	1.6	5.3	4.8	7.0
1999	2.2	5.7	4.7	7.6
2000	3.4	6.0	5.9	8.2
2001	2.9	5.0	3.5	7.8
2002	1.6	4.6	1.6	7.4
2003	1.9	4.1	1.0	6.6
2004	2.7	4.3	1.4	6.2

FLORIDA POWER & LIGHT COMPANY

Trends in Capital Costs (Continued)

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield
2002				
January	1.1%	5.0%	1.7%	7.7%
February	1.1	4.9	1.7	7.5
March	1.5	5.3	1.8	7.8
April	1.6	5.2	1.7	7.6
May	1.2	5.2	1.7	7.5
June	1.1	4.9	1.7	7.4
July	1.5	4.7	1.7	7.3
August	1.8	4.3	1.6	7.2
September	1.5	3.9	1.6	7.1
October	2.0	3.9	1.6	7.2
November	2.2	4.1	1.3	7.1
December	2.4	4.0	1.2	7.1
2003				
January	2.6%	4.1%	1.2%	7.1%
February	3.0	3.9	1.2	6.9
March	3.0	3.8	1.1	6.8
April	2.1	4.0	1.1	6.6
May	2.1	3.6	1.1	6.4
June	2.1	3.7	0.9	6.2
July	2.1	4.0	0.9	6.6
August	2.2	4.5	1.0	6.8
September	2.3	4.3	1.0	6.6
October	2.0	4.3	0.9	6.4
November	1.8	4.3	1.0	6.4
December	1.8	4.3	0.9	6.3
2004				
January	1.9%	4.2%	0.9%	6.2%
February	1.7	4.1	0.9	6.2
March	1.7	3.8	0.9	6.0
April	2.3	4.4	0.9	6.4
May	3.1	4.7	1.0	6.6
June	3.3	4.7	1.3	6.5
July	3.0	4.5	1.4	6.3
August	2.7	4.3	1.5	6.1
September	2.5	4.1	1.6	6.0
October	3.2	4.1	1.8	5.9
November	3.5	4.2	2.1	6.0
December	3.3	4.2	2.2	5.9

FLORIDA POWER & LIGHT COMPANY

Trends in Capital Costs (Continued)

2005	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield
January	3.0%	4.2%	2.4%	5.8%
February	3.0	4.2	2.6	5.6
March	3.1	4.5	2.8	5.8
April	3.5	4.3	2.8	5.6
May	2.8	4.1	2.9	5.5

Source: Economic Report of the President, Mergent's Bond Record, Federal Reserve Statistical Release, Consumer Price Index Summary.

FLORIDA POWER & LIGHT COMPANY

DCF Electric Utility Proxy Group

	Company	2004 Equity Ratio	Beta	Safety	Financial Strength	Nuclear Generation
(1)	Ameren	53.0%	0.75	1	A+	Yes
(2)	Entergy Corp.	53.0	0.75	2	A	Yes
(3)	FPL Group	48.5	0.75	1	A+	Yes
(4)	Great Plains	53.4	0.80	2	A	Yes
(5)	Progress Energy	44.3	0.85	2	B++	Yes
(6)	SCANA Corp.	42.6	0.75	2	A	Yes
(7)	Southern Co.	44.1	0.65	1	A	Yes
(8)	Vectren	50.5	0.75	2	A	No
(9)	WPS Resources	51.5	0.75	2	B++	Yes
(10)	Westar	45.5	0.80	2	B++	Yes
(11)	Wisconsin Energy	43.3	0.70	2	B++	Yes
	Average	**48.2%**	**75.0%**	**1.7**	**--**	**Yes**

Source: Value Line Investment Survey, April 1 – June 3, 2005.

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Schedule MIK-4
Page 1 of 1
Dividend Yields

FLORIDA POWER & LIGHT COMPANY

Dividend Yields for the Proxy Electric
Utility Companies, December 2004-May 2005

	Company	December	January	February	March	April	May	Average
(1)	Ameren	5.1%	5.1%	4.9%	5.2%	4.9%	4.7 %	4.98%
(2)	Entergy Corp.	3.2	3.1	3.1	3.1	2.9	3.0	3.07
(3)	FPL Group	3.6	3.5	3.6	3.5	3.5	3.5	3.53
(4)	Great Plains	5.5	5.5	5.4	5.4	5.4	5.3	5.42
(5)	Progress Energy	5.2	5.3	5.4	5.6	5.6	5.3	5.40
(6)	SCANA	3.7	3.7	4.1	4.1	4.0	3.7	3.88
(7)	Southern Co.	4.3	4.2	4.5	4.5	4.5	4.4	4.40
(8)	Vectren	4.4	4.3	4.4	4.4	4.4	4.3	4.37
(9)	WPS Resources	4.4	4.3	4.3	4.2	4.2	4.0	4.23
(10)	Westar Energy	4.0	3.9	4.0	4.3	4.0	4.0	4.03
(11)	Wisconsin Energy	2.5	2.6	2.5	2.5	2.5	2.4	2.50
	Average	**4.17%**	**4.16%**	**4.20%**	**4.25%**	**4.17%**	**4.05%**	**4.17%**

Source: Standards & Poors, Stock Guide, January-June 2005 issues.

FLORIDA POWER & LIGHT COMPANY

DCF Analysis Summary

(1)	Proxy Group Dividend Yield	
	(December 2004 – May 2005)	4.2% (See Schedule MIK-4)
(2)	Adjusted Yield (4.2 x 1.025)	4.3%
(3)	Growth Rate Range	4.5-5.0% (Page 2 of this schedule)
(4)	Total Investor Return	8.8-9.3%
(5)	Flotation Adjustment	0.1%
(6)	Cost of Equity ((4) + (5))	8.9-9.4% ((4) + (5))
(7)	Performance Adder	0.0-0.5%
(8)	Return on Equity Award (with adder)	8.9-9.9% ((6) + (7))
	Recommendation Range	**9.0 to 10.0%**
	Recommendation Midpoint	**9.5%**

FLORIDA POWER & LIGHT COMPANY

Earnings Growth Rate Projections
(5-year growth rates)

	Company	Zacks	First Call	Standard & Poors (IBES)	Value Line*
(1)	Ameren	4.9%	3.0%	3.0%	0.5/2.1%
(2)	Entergy Corp.	7.0	7.0	7.0	6.5/7.6
(3)	FPL Group	5.3	5.0	5.0	7.5/3.7
(4)	Great Plains	3.2	3.0	3.0	0.0/(1.8)
(5)	Progress Energy	3.8	4.0	4.0	0.0/1.9
(6)	Vectren	5.9	4.5	6.0	4.5/6.3
(7)	Southern Co.	4.5	5.0	5.0	4.0/4.0
(8)	SCANA	4.6	4.5	5.0	4.5/4.0
(9)	WPS Resources	4.7	4.5	4.0	6.5/1.1
(10)	Westar Energy	4.0	3.0	3.0	6.0/8.4
(11)	Wisconsin Energy	6.1	6.5	6.0	4.0/8.3
	Average	**4.9%**	**4.5%**	**4.6%**	**4.0/4.1%**

Sources: Zacks, MSN Money website, May 2005
First Call, CNN Financial website, May 2005
S&P Earnings Guide, May 2005
Value Line Investment Survey, April 1 – June 3, 2005

* The first Value Line growth rate figure published by Value Line. The second is a calculated value using 2004 earnings as a base year and the standard compound growth formula.

FLORIDA POWER & LIGHT COMPANY

Value Line Growth Statistics
(5-year projected growth rates)

	Company	Earnings Per Share	Dividends Per Share	Book Value Per Share	Retained Earnings Growth*
(1)	Ameren	0.5%	0.0%	4.0%	2.0%
(2)	Entergy Corp.	6.5	11.5	5.0	5.0
(3)	FPL Group	7.5	10.5	8.5	4.5
(4)	Great Plains	0.0	0.0	5.0	3.5
(5)	Progress Energy	0.0	2.0	2.5	2.5
(6)	SCANA Corp.	4.5	5.5	6.0	4.5
(7)	Southern Co.	4.0	3.5	6.0	4.5
(8)	Vectren	4.5	3.5	4.0	3.5
(9)	WPS Resources	6.5	2.0	6.0	5.0
(10)	Westar Energy	6.0	2.5	5.0	3.5
(11)	Wisconsin Energy	4.0	4.5	6.5	6.0
	Average	**4.0%**	**4.1%**	**5.3%**	**4.0%**

Source: Value Line Investment Survey, April 1, June 3, 2005

* Figures are Value Line's projection of retained earnings growth for 2008 – 2010.

FLORIDA POWER & LIGHT COMPANY

Historical 5-Year Growth Rates
For The Electric Utility Proxy Group

	Company	Earnings Per Share	Dividends Per Share	Book Value Per Share
(1)	Ameren	2.5%	0.0%	2.5%
(2)	Entergy Corp.	8.5	(3.5)	5.0
(3)	FPL Group	4.5	4.0	6.0
(4)	Great Plains	7.0	0.0	0.0
(5)	Progress Energy	5.5	3.0	8.5
(6)	SCANA Corp.	6.5	(1.0)	3.0
(7)	Southern Co.	2.5	1.0	(1.5)
(8)	Vectren	--	--	--
(9)	WPS Resources	7.0	2.0	5.0
(10)	Westar Energy	3.0	(15.0)	(13.0)
(11)	Wisconsin Energy	9.5	(12.0)	3.5
	Average	**6.0%**	**(2.2)%**	**1.5%**

Source: Value Line Investment Survey, April 1 – June 3, 2005.

FLORIDA POWER & LIGHT COMPANY

Capital Asset Pricing Model Analysis

A. Model Specification

K_e = $RF + \beta (R_m - R_f)$, where:

K_e = cost of equity

R_f = return on risk free asset

R_m = expected return on the stock market

β = beta statistic (non diversifiable risk)

B. Data Inputs

Risk Free Return:	3-month Treasury: 2.6% long-term Treasury: 4.5 - 5.0% (2005 yields on 20-year bonds)
Market Return:	10-12% (See page 2 of this schedule.)
Beta:	0.75 (See Schedule MIK-3.)

C. Model Calculations

Low end:	$K_e = 4.5\% + 0.75\ (10\text{-}4.5) = 8.63\%$
Upper end:	$K_e = 5.0\% + 0.75\ (12\text{-}5.0) = 10.25\%$
Midpoint:	$K_e = 4.75\% + 0.75\ (11\text{-}4.75) = 9.44\%$

FLORIDA POWER & LIGHT COMPANY

Stock Market Returns Estimates

(1) <u>Ibbotson Associates Historical Returns</u>

K_e = 6.6% + 4.75% = 11.35% (arithmetic mean);
K_e = 5.0% + 4.75% = 9.75 (geometric mean)
(Source: Ibbotson Associates, 2004)

(2) <u>Ibbotson/Chen Supply Side Model</u>

K_e = 5.9% + 4.75% = 10.65%

(Ibbotson/Chen estimate an arithmetic risk premium of 5.9% for stocks over the historical time period, 1926-2000, excluding effects of rising P/E ratios.)

(3) <u>Industrial Composite DCF</u>

K_e = 1.9% + 9.0% = 10.9%

(Value Line Industrial Composite, March 8, 2005. Dividend yield is 1.9% and growth rate is 7.0% for projected earnings and 11.0% for 2008-2010 earnings retention growth. Averaging the 7.0% and 11.0% provides a growth rate of 9.0%.)

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Page 1 of 2
Rates Comparison

FLORIDA POWER & LIGHT COMPANY

Residential Rates Comparison for the
Industry Peer Group, 2004
(¢/kWh)

(1)	Alabama Power	7.75¢	(19)	Kentucky Utilities	4.86¢
(2)	Appalachian Power	5.34	(20)	Entergy Louisiana	8.71
(3)	Arizona Public Service	8.53	(21)	MidAmerica Energy	8.67
(4)	Entergy Arkansas	7.67	(22)	Nevada Power	9.56
(5)	Carolina Power & Light	8.32	(23)	Northern States Power	7.84
(6)	AEP Texas Central	--	(24)	Ohio Power	6.62
(7)	Cinn. Gas & Electric	7.27	(25)	OG&E	7.75
(8)	Columbus Southern Power	7.57	(26)	Portland General	8.01
(9)	Consumers Energy	8.07	(27)	PSC Colorado	8.44
(10)	Dayton Power & Light	--	(28)	PSI Energy	6.97
(11)	Detroit Edison	8.92	(29)	PSC Oklahoma	7.08
(12)	Duke Power	7.66	(30)	Puget Sound	6.27
(13)	**Florida Power & Light**	**9.06**	(31)	South Carolina E&G	8.77
(14)	Florida Power Corp.	9.34	(32)	Tampa Electric	9.89
(15)	Georgia Power	7.57	(33)	Union Electric	6.54
(16)	Entergy Gulf States	8.81	(34)	Dominion Virginia	8.43
(17)	Interstate Power & Light	9.86	(35)	Wisconsin Electric	9.13
(18)	Indiana Michigan	6.84			

Group Average: 7.94¢/kWh (unweighted average)

Source: Edison Electric Institute, Typical Bills and Average Rates Report, Winter 2005

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Schedule MIK-7
Page 2 of 2
Rates Comparison

FLORIDA POWER & LIGHT COMPANY

Residential Rates Comparison for the
Southeast Region, 2004
(¢/kWh)

Florida		Alabama	
Florida Power & Light	**9.06¢**	Alabama Power	7.75¢
Gulf Power Co.	7.83		
Progress Energy	9.34	Mississippi	
Tampa Electric	9.89		
		Entergy Mississippi	9.19
North Carolina		Mississippi Power	8.68
Duke Power	7.66	Arkansas	
Progress Energy	8.32		
		Entergy Arkansas	7.76
South Carolina			
		Louisiana	
South Carolina Electric & Gas	8.77		
		Cleco Power	8.50
Virginia		Entergy Gulf States	8.81
		Entergy Louisiana	8.71
Dominion Energy	8.43	Entergy New Orleans	8.61

Southeast Average: 8.58¢ (unweighted average)

Source: Edison Electric Institute, Typical Bills and Average Rates Report, Winter 2005

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Qualifications

APPENDIX A

QUALIFICATIONS OF

MATTHEW I. KAHAL

MATTHEW I. KAHAL

Mr. Kahal is currently an independent consulting economist, specializing in energy economics, public utility regulation and financial analysis. Over the past two decades, his work has encompassed electric utility integrated resource planning (IRP), power plant licensing and a wide range of utility financial issues. In the financial area he has conducted numerous cost of capital studies and addressed other financial issues for electric, gas, telephone and water utilities. Mr. Kahal's work in recent years has shifted to electric utility restructuring, mergers and competition.

Mr. Kahal has provided expert testimony on more than 250 occasions before state and federal regulatory commissions and the U.S. Congress. His testimony has covered need for power, integrated resource planning, cost of capital, purchased power practices and contracts, merger economics, industry restructuring and various other regulatory policy issues.

Education:

B.A. (Economics) - University of Maryland, 1971.

M.A. (Economics) - University of Maryland, 1974.

Ph.D. candidate - University of Maryland, completed all course work and qualifying examinations.

Previous Employment:

1981-2001 - Exeter Associates, Inc. (founding Principal).

1980-1981 - Member of the Economic Evaluation Directorate, The Aerospace Corporation, Washington, D.C. office.

1977-1980 - Economist, Washington, D.C. consulting firm.

1972-1977 - Research/Teaching Assistant and Instructor, Department of Economics, University of Maryland (College Park).

1975-1977 - Lecturer in Business/Economics, Montgomery College.

Professional Work Experience:

Mr. Kahal has more than twenty years experience managing and conducting consulting assignments relating to public utility economics and regulation. In 1981, he and five colleagues founded the firm of Exeter Associates, Inc. and for the next 20 years he served as a Principal and corporate officer in the firm. During that time, he supervised multi-million dollar support contracts with the State of Maryland and directed the technical work conducted both by Exeter professional staff and numerous subcontractors. Additionally, Mr. Kahal took the lead role at Exeter in consulting to the firm's other governmental and private clients in the areas of financial analysis, utility mergers, electric restructuring and utility purchase power contracts.

At the Aerospace Corporation, Mr. Kahal served as an economic consultant to the Strategic Petroleum Reserve (SPR). In that capacity he participated in a detailed financial assessment of the SPR, and developed an econometric forecasting model of U.S. petroleum industry inventories. That study has been used to determine the extent to which private sector petroleum stocks can be expected to protect the U.S. from the impacts of oil import interruptions.

Before entering consulting, Mr. Kahal held faculty positions with the Department of Economics at the University of Maryland and with Montgomery College teaching courses on economic principles, business and economic development.

Publications and Consulting Reports:

Projected Electric Power Demands of the Baltimore Gas and Electric Company, Maryland Power Plant Siting Program, 1979.

Projected Electric Power Demands of the Allegheny Power System, Maryland Power Plant Siting Program, January 1980.

An Econometric Forecast of Electric Energy and Peak Demand on the Delmarva Peninsula, Maryland Power Plant Siting Program, March 1980 (with Ralph E. Miller).

A Benefit/Cost Methodology of the Marginal Cost Pricing of Tennessee Valley Authority Electricity, prepared for the Board of Directors of the Tennessee Valley Authority, April 1980.

An Evaluation of the Delmarva Power and Light Company Generating Capacity Profile and Expansion Plan, (Interim Report), prepared for the Delaware Office of the Public Advocate, July 1980, (with Sharon L. Mason).

Rhode Island-DOE Electric Utilities Demonstration Project, Third Interim Report on Preliminary Analysis of the Experimental Results, prepared for the Economic Regulatory Administration, U.S. Department of Energy, July 1980.

Petroleum Inventories and the Strategic Petroleum Reserve, The Aerospace Corporation, prepared for the Strategic Petroleum Reserve Office, U.S. Department of Energy, December 1980.

Alternatives to Central Station Coal and Nuclear Power Generation, prepared for Argonne National Laboratory and the Office of Utility Systems, U.S. Department of Energy, August 1981.

"An Econometric Methodology for Forecasting Power Demands," Conducting Need-for-Power Review for Nuclear Power Plants (D.A. Nash, ed.), U.S. Nuclear Regulatory Commission, NUREG-0942, December 1982.

State Regulatory Attitudes Toward Fuel Expense Issues, prepared for the Electric Power Research Institute, July 1983, (with Dale E. Swan).

"Problems in the Use of Econometric Methods in Load Forecasting," Adjusting to Regulatory, Pricing and Marketing Realities (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1983.

Proceedings of the Maryland Conference on Electric Load Forecasting, (editor and contributing author), Maryland Power Plant Siting Program, PPES-83-4, October 1983.

"The Impacts of Utility-Sponsored Weatherization Programs: The Case of Maryland Utilities," (with others), in Government and Energy Policy (Richard L. Itteilag, ed.), 1983.

Power Plant Cumulative Environmental Impact Report, contributing author, (Paul E. Miller, ed.) Maryland Department of Natural Resources, January 1984.

Projected Electric Power Demands for the Potomac Electric Power Company, three volumes with Steven L. Estomin), prepared for the Maryland Power Plant Siting Program, March 1984.

"An Assessment of the State-of-the-Art of Gas Utility Load Forecasting," (with Thomas Bacon, Jr. and Steven L. Estomin), published in the Proceedings of the Fourth NARUC Biennial Regulatory Information Conference, 1984.

"Nuclear Power and Investor Perceptions of Risk," (with Ralph E. Miller), published in The Energy Industries in Transition: 1985-2000 (John P. Weyant and Dorothy Sheffield, eds.), 1984.

The Financial Impact of Potential Department of Energy Rate Recommendations on the Commonwealth Edison Company, prepared for the U.S. Department of Energy, October 1984.

"Discussion Comments," published in Impact of Deregulation and Market Forces on Public Utilities: The Future of Regulation (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1985.

An Econometric Forecast of the Electric Power Loads of Baltimore Gas and Electric Company, two volumes (with others), prepared for the Maryland Power Plant Siting Program, 1985.

A Survey and Evaluation of Demand Forecast Methods in the Gas Utility Industry, prepared for the Public Utilities Commission of Ohio, Forecasting Division, November 1985, (with Terence Manuel).

A Review and Evaluation of the Load Forecasts of Houston Lighting & Power Company and Central Power & Light Company -- Past and Present, prepared for the Texas Public Utility Commission, December 1985, (with Marvin H. Kahn).

Power Plant Cumulative Environmental Impact Report for Maryland, principal author of three of the eight chapters in the report (Paul E. Miller, ed.), PPSP-CEIR-5, March 1986.

"Potential Emissions Reduction from Conservation, Load Management, and Alternative Power," published in Acid Deposition in Maryland: A Report to the Governor and General Assembly, Maryland Power Plant Research Program, AD-87-1, January 1987.

Determination of Retrofit Costs at the Oyster Creek Nuclear Generating Station, March 1988, prepared for Versar, Inc., New Jersey Department of Environmental Protection.

Excess Deferred Taxes and the Telephone Utility Industry, April 1988, prepared on behalf of the National Association of State Utility Consumer Advocates.

Toward a Proposed Federal Policy for Independent Power Producers, comments prepared on behalf of the Indiana Consumer Counselor, FERC Docket EL87-67-000, November 1987.

Review and Discussion of Regulations Governing Bidding Programs, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

A Review of the Proposed Revisions to the FERC Administrative Rules on Avoided Costs and Related Issues, prepared for the Pennsylvania Office of Consumer Advocate, April 1988.

Review and Comments on the FERC NOPR Concerning Independent Power Producers, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

The Costs to Maryland Utilities and Ratepayers of an Acid Rain Control Strategy -- An Updated Analysis, prepared for the Maryland Power Plant Research Program, October 1987, AD-88-4.

"Comments," in New Regulatory and Management Strategies in a Changing Market Environment (Harry M. Trebing and Patrick C. Mann, editors), Proceedings of the Institute of Public Utilities Eighteenth Annual Conference, 1987.

Electric Power Resource Planning for the Potomac Electric Power Company, prepared for the Maryland Power Plant Research Program, July 1988.

Power Plant Cumulative Environmental Impact Report for Maryland (Thomas E. Magette, ed.) authored two chapters, November 1988, PPRP-CEIR-6.

Resource Planning and Competitive Bidding for Delmarva Power & Light Company, October 1990, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

Electric Power Rate Increases and the Cleveland Area Economy, prepared for the Northeast Ohio Areawide Coordinating Agency, October 1988.

An Economic and Need for Power Evaluation of Baltimore Gas & Electric Company's Perryman Plant, May 1991, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

The Cost of Equity Capital for the Bell Local Exchange Companies in a New Era of Regulation, October 1991, presented at the Atlantic Economic Society 32nd Conference, Washington, D.C.

A Need for Power Review of Delmarva Power & Light Company's Dorchester Unit 1 Power Plant, March 1993, prepared for the Maryland Department of National Resources (with M. Fullenbaum)

The AES Warrior Run Project: Impact on Western Maryland Economic Activity and Electric Rates, February 1993, prepared for the Maryland Power Plant Research Program (with Peter Hall).

An Economic Perspective on Competition and the Electric Utility Industry, November 1994. Prepared for the Electric Consumers' Alliance.

PEPCO's Clean Air Act Compliance Plan: Status Report, prepared for the Maryland Power Plant Research Plan, January 1995 (w/Diane Mountain, Environmental Resources Management, Inc.).

The FERC Open Access Rulemaking: A Review of the Issues, prepared for the Indiana Office of Utility Consumer Counselor and the Pennsylvania Office of Consumer Advocate, June 1995.

A Status Report on Electric Utility Restructuring: Issues for Maryland, prepared for the Maryland Power Plant Research Program, November 1995 (with Daphne Psacharopoulos).

Modeling the Financial Impacts on the Bell Regional Holding Companies from Changes in Access Rates, prepared for MCI Corporation, May 1996.

The CSEF Electric Deregulation Study: Economic Miracle or the Economists' Cold Fusion?, prepared for the Electric Consumers' Alliance, Indianapolis, Indiana, October 1996.

Reducing Rates for Interstate Access Service: Financial Impacts on the Bell Regional Holding Companies, prepared for MCI Corporation, May 1997.

The New Hampshire Retail Competition Pilot Program: A Preliminary Evaluation, July 1997, prepared for the Electric Consumers' Alliance (with Jerome D. Mierzwa).

Electric Restructuring and the Environment: Issue Identification for Maryland, March 1997, prepared for the Maryland Power Plant Research Program (with Environmental Resource Management, Inc.)

An Analysis of Electric Utility Embedded Power Supply Costs, prepared for Power-Gen International Conference, Dallas, Texas, December 1997.

Market Power Outlook for Generation Supply in Louisiana, December 2000, prepared for the Louisiana Public Service Commission (with others).

A Review of Issues Concerning Electric Power Capacity Markets, prepared for the Maryland Power Plant Research Program, December 2001 (with B. Hobbs and J. Inon).

Conference and Workshop Presentations:

Workshop on State Load Forecasting Programs, sponsored by the Nuclear Regulatory Commission and Oak Ridge National Laboratory, February 1982 (presentation on forecasting methodology).

Fourteenth Annual Conference of the Michigan State University Institute for Public Utilities, December 1982 (presentation on problems in forecasting).

Conference on Conservation and Load Management, sponsored by the Massachusetts Energy Facilities Siting Council, May 1983 (presentation on cost-benefit criteria).

Maryland Conference on Load Forecasting, sponsored by the Maryland Power Plant Siting Program and the Maryland Public Service Commission, June 1983 (presentation on overforecasting power demands).

The 5th Annual Meetings of the International Association of Energy Economists, June 1983 (presentation on evaluating weatherization programs).

The NARUC Advanced Regulatory Studies Program (presented lectures on capacity planning for electric utilities), February 1984.

The 16th Annual Conference of the Institute of Public Utilities, Michigan State University (discussant on phase-in and excess capacity), December 1984.

U.S. Department of Energy Utilities Conference, Las Vegas, Nevada (presentation of current and future regulatory issues), May 1985.

The 18th Annual Conference of the Institute of Public Utilities, Michigan State University, Williamsburg, Virginia, December 1986 (discussant on cogeneration).

The NRECA Conference on Load Forecasting, sponsored by the National Rural Electric Cooperative Association, New Orleans, Louisiana, December 1987 (presentation on load forecast accuracy).

The Second Rutgers/New Jersey Department of Commerce Annual Conference on Energy Policy in the Middle Atlantic States, Rutgers University, April 1988 (presentation on spot pricing of electricity).

The NASUCA 1988 Mid-Year Meeting, Annapolis, Maryland, June 1988, sponsored by the National Association of State Utility Consumer Advocates (presentation on the FERC electricity avoided cost NOPRs).

The Thirty Second Atlantic Economic Society Conference, Washington, D.C., October 1991 (presentation of a paper on cost of capital issues for the Bell Operating Companies).

The NASUCA 1993 Mid-Year Meeting, St. Louis, Missouri, sponsored by the National Association of State Utility Consumer Advocates, June 1993 (presentation on regulatory issues concerning electric utility mergers).

The NASUCA and NARUC annual meetings in New York City, November 1993 (presentations and panel discussions on the emerging FERC policies on transmission pricing).

The NASUCA annual meetings in Reno, Nevada, November 1994 (presentation concerning the FERC NOPR on stranded cost recovery).

U.S. Department of Energy Utilities/Energy Management Workshop, March 1995 (presentation concerning electric utility competition).

The 1995 NASUCA Mid-Year Meeting, Breckenridge, Colorado, June 1995, (presentation concerning the FERC rulemaking on electric transmission open access).

The 1996 NASUCA Mid-Year Meeting, Chicago, Illinois, June 1996 (presentation concerning electric utility merger issues).

Conference on "Restructuring the Electric Industry," sponsored by the National Consumers League and Electric Consumers Alliance, Washington, D.C., May 1997 (presentation on retail access pilot programs).

The 1997 Mid-Atlantic Conference of Regulatory Utilities Commissioners (MARUC), Hot Springs, Virginia, July 1997 (presentation concerning electric deregulation issues).

Power-Gen '97 International Conference, Dallas, Texas, December 1997 (presentation concerning utility embedded costs of generation supply).

Consumer Summit on Electric Competition, sponsored by the National Consumers League and Electric Consumers' Alliance, Washington, D.C., March 2001 (presentation concerning generation supply and reliability).

National Association of State Utility Consumer Advocates, Mid-Year Meetings, Austin, Texas, June 16-17, 2002 (presenter and panelist on RTO/Standard Market Design issues).

Louisiana State Bar Association, Public Utility Section, October 2, 2002. (Presentation on Performance-Based Ratemaking and panelist on RTO issues). Baton Rouge, Louisiana.

Virginia State Corporation Commission/Virginia State Bar, Twenty Second National Regulatory Conference, May 10, 2004. (Presentation on Electric Transmission System Planning.) Williamsburg, Virginia.

Docket No. 050045-EI
Kahal Exhibit No. __
Qualifications

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	Docket Number	Utility	Jurisdiction	Client	Subject
1.	27374 & 27375 October 1978	Long Island Lighting Company	New York Counties	Nassau & Suffolk	Economic impacts of proposed rate increase
2.	6807 January 1978	Generic	Maryland	MD Power Plant Siting Program	Load forecasting
3.	78-676-EL-AIR February 1978	Ohio Power Company	Ohio	Ohio Consumers' Counsel	Test year sales and revenues
4.	17667 May 1979	Alabama Power Company	Alabama	Attorney General	Test year sales, revenues, costs and load forecasts
5.	None April 1980	Tennessee Valley Authority	TVA Board	League of Women Voters	Time-of-use pricing
6.	R-80021082	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Load forecasting, marginal cost pricing
7.	7259 (Phase I) October 1980	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load forecasting
8.	7222 December 1980	Delmarva Power & Light Company	Maryland	MD Power Plant Siting Program	Need for plant, load forecasting
9.	7441 June 1981	Potomac Electric Power Company	Maryland	Commission Staff	PURPA standards
10.	7159 May 1980	Baltimore Gas & Electric	Maryland	Commission Staff	Time-of-use pricing
11.	81-044-E-42T	Monongahela Power	West Virginia	Commission Staff	Time-of-use rates
12.	7259 (Phase II) November 1981	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load forecasting, load management
13.	1606 September 1981	Blackstone Valley Electric and Narragansett	Rhode Island	Division of Public Utilities	PURPA standards
14.	RID 1819 April 1982	Pennsylvania Bell	Pennsylvania	Office of Consumer Advocate	Rate of return
15.	82-0152 July 1982	Illinois Power Company	Illinois	U.S. Department of Defense	Rate of return, CWIP

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	Docket Number	Utility	Jurisdiction	Client	Subject
16.	7559 September 1982	Potomac Edison Company	Maryland	Commission Staff	Cogeneration
17.	820150-EU September 1982	Gulf Power Company	Florida	Federal Executive Agencies	Rate of return, CWIP
18.	82-057-15 January 1983	Mountain Fuel Supply Company	Utah	Federal Executive Agencies	Rate of return, capital structure
19.	5200 August 1983	Texas Electric Service Company	Texas	Federal Executive Agencies	Cost of equity
20.	28069 August 1983	Oklahoma Natural Gas	Oklahoma	Federal Executive Agencies	Rate of return, deferred taxes, capital structure, attrition
21.	83-0537 February 1984	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of return, capital structure, financial capability
22.	84-035-01 June 1984	Utah Power & Light Company	Utah	Federal Executive Agencies	Rate of return
23.	U-1009-137 July 1984	Utah Power & Light Company	Idaho	U.S. Department of Energy	Rate of return, financial condition
24.	R-842590 August 1984	Philadelphia Electric Company	Pennsylvania	Office of Consumer Advocate	Rate of return
25.	840086-EI August 1984	Gulf Power Company	Florida	Federal Executive Agencies	Rate of return, CWIP
26.	84-122-E August 1984	Carolina Power & Light Company	South Carolina	South Carolina Consumer Advocate	Rate of return, CWIP, load forecasting
27.	CGC-83-G & CGC-84-G October 1984	Columbia Gas of Ohio	Ohio	Ohio Division of Energy	Load forecasting

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	Docket Number	Utility	Jurisdiction	Client	Subject
28.	R-842621 October 1984	Western Pennsylvania Water Company	Pennsylvania	Office of Consumer Advocate	Test year sales
29.	R-842710 January 1985	ALLTEL Pennsylvania Inc.	Pennsylvania	Office of Consumer Advocate	Rate of return
30.	ER-504 February 1985	Allegheny Generating Company	FERC	Office of Consumer Advocate	Rate of return
31.	R-842632 March 1985	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Rate of return, conservation, time-of-use rates
32.	83-0537 & 84-0555 April 1985	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of return, incentive rates, rate base
33.	Rulemaking Docket No. 11, May 1985	Generic	Delaware	Delaware Commission Staff	Interest rates on refunds
34.	29450 July 1985	Oklahoma Gas & Electric Company	Oklahoma	Oklahoma Attorney General	Rate of return, CWIP in rate base
35.	1811 August 1985	Bristol County Water Company	Rhode Island	Division of Public Utilities	Rate of return, capital structure
36.	R-850044 & R-850045 August 1985	Quaker State & Continental Telephone Companies	Pennsylvania	Office of Consumer Advocate	Rate of return
37.	R-850174 November 1985	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of return, financial conditions
38.	U-1006-265 March 1986	Idaho Power Company	Idaho	U.S. Department of Energy	Power supply costs and models
39.	EL-86-37 & EL-86-38 September 1986	Allegheny Generating Company	FERC	PA Office of Consumer Advocate	Rate of return
40.	R-850287 June 1986	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of return
41.	1849 August 1986	Blackstone Valley Electric	Rhode Island	Division of Public Utilities	Rate of return, financial condition
42.	86-297-GA-AIR November 1986	East Ohio Gas Company	Ohio	Ohio Consumers' Counsel	Rate of return

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	Docket Number	Utility	Jurisdiction	Client	Subject
43.	U-16945 December 1986	Louisiana Power & Light Company	Louisiana	Public Service Commission	Rate of return, rate phase-in plan
44.	Case No. 7972 February 1987	Potomac Electric Power Company	Maryland	Commission Staff	Generation capacity planning, purchased power contract
45.	EL-86-58 & EL-86-59 March 1987	System Energy Resources and Middle South Services	FERC	Louisiana PSC	Rate of return
46.	ER-87-72-001 April 1987	Orange & Rockland	FERC	PA Office of Consumer Advocate	Rate of return
47.	U-16945 April 1987	Louisiana Power & Light Company	Louisiana	Commission Staff	Revenue requirement update phase-in plan
48.	P-870196 May 1987	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contract
49.	86-2025-EL-AIR June 1987	Cleveland Electric Illuminating Company	Ohio	Ohio Consumers' Counsel	Rate of return
50.	86-2026-EL-AIR June 1987	Toledo Edison Company	Ohio	Ohio Consumers' Counsel	Rate of return
51.	87-4 June 1987	Delmarva Power & Light Company	Delaware	Commission Staff	Cogeneration/small power
52.	1872 July 1987	Newport Electric Company	Rhode Island	Commission Staff	Rate of return
53.	WO 8606654 July 1987	Atlantic City Sewerage Company	New Jersey	Resorts International	Financial condition
54.	7510 August 1987	West Texas Utilities Company	Texas	Federal Executive Agencies	Rate of return, phase-in
55.	8063 Phase I October 1987	Potomac Electric Power Company	Maryland	Power Plant Research Program	Economics of power plant site selection
56.	00439 November 1987	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Cogeneration economics

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	Docket Number	Utility	Jurisdiction	Client	Subject
57.	RP-87-103 February 1988	Panhandle Eastern Pipe Line Company	FERC	Indiana Utility Consumer Counselor	Rate of return
58.	EC-88-2-000 February 1988	Utah Power & Light Co. PacifiCorp	FERC	Nucor Steel	Merger economics
59.	87-0427 February 1988	Commonwealth Edison Company	Illinois	Federal Executive Agencies	Financial projections
60.	870840 February 1988	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of return
61.	870832 March 1988	Columbia Gas of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of return
62.	8063 Phase II July 1988	Potomac Electric Power Company	Maryland	Power Plant Research Program	Power supply study
63.	8102 July 1988	Southern Maryland Electric Cooperative	Maryland	Power Plant Research Program	Power supply study
64.	10105 August 1988	South Central Bell Telephone Co.	Kentucky	Attorney General	Rate of return, incentive regulation
65.	00345 August 1988	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Need for power
66.	U-17906 September 1988	Louisiana Power & Light Company	Louisiana	Commission Staff	Rate of return, nuclear power costs Industrial contracts
67.	88-170-EL-AIR October 1988	Cleveland Electric Illuminating Co.	Ohio	Northeast-Ohio Areawide Coordinating Agency	Economic impact study
68.	1914 December 1988	Providence Gas Company	Rhode Island	Commission Staff	Rate of return
69.	U-12636 & U-17649 February 1989	Louisiana Power & Light Company	Louisiana	Commission Staff	Disposition of litigation proceeds
70.	00345 February 1989	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Load forecasting

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	Docket Number	Utility	Jurisdiction	Client	Subject
71.	RP88-209 March 1989	Natural Gas Pipeline of America	FERC	Indiana Utility Consumer Counselor	Rate of return
72.	8425 March 1989	Houston Lighting & Power Company	Texas	U.S. Department of Energy	Rate of return
73.	EL89-30-000 April 1989	Central Illinois Public Service Company	FERC	Soyland Power Coop, Inc.	Rate of return
74.	R-891208 May 1989	Pennsylvania American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of return
75.	89-0033 May 1989	Illinois Bell Telephone Company	Illinois	Citizens Utility Board	Rate of return
76.	881167-EI May 1989	Gulf Power Company	Florida	Federal Executive Agencies	Rate of return
77.	R-891218 July 1989	National Fuel Gas Distribution Company	Pennsylvania	Office of Consumer Advocate	Sales forecasting
78.	8063, Phase III Sept. 1989	Potomac Electric Power Company	Maryland	Depart. Natural Resources	Emissions Controls
79.	37414-S2 October 1989	Public Service Company of Indiana	Indiana	Utility Consumer Counselor	Rate of return, DSM, off-system sales, incentive regulation
80.	October 1989	Generic	U.S. House of Reps. Comm. on Ways & Means	NA	Excess deferred income tax
81.	38728 November 1989	Indiana Michigan Power Company	Indiana	Utility Consumer Counselor	Rate of return
82.	RP89-49-000 December 1989	National Fuel Gas Supply Corporation	FERC	PA Office of Consumer Advocate	Rate of return
83.	R-891364 December 1989	Philadelphia Electric Company	Pennsylvania	PA Office of Consumer Advocate	Financial impacts (surrebuttal only)
84.	RP89-160-000 January 1990	Trunkline Gas Company	FERC	Indiana Utility Consumer Counselor	Rate of return

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	Docket Number	Utility	Jurisdiction	Client	Subject
85.	EL90-16-000 November 1990	System Energy Resources, Inc.	FERC	Louisiana Public Service Commission	Rate of return
86.	89-624 March 1990	Bell Atlantic	FCC	PA Office of Consumer Advocate	Rate of return
87.	8245 March 1990	Potomac Edison Company	Maryland	Depart. Natural Resources	Avoided Cost
88.	000586 March 1990	Public Service Company of Oklahoma	Oklahoma	Smith Cogeneration Mgmt.	Need for Power
89.	38868 March 1990	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of return
90.	1946 March 1990	Blackstone Valley Electric Company	Rhode Island	Division of Public Utilities	Rate of return
91.	000776 April 1990	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration Mgmt.	Need for Power
92.	890366 May 1990, December 1990	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Competitive Bidding Program Avoided Costs
93.	EC-90-10-000 May 1990	Northeast Utilities	FERC	Maine PUC, et. al.	Merger, Market Power, Transmission Access
94.	ER-891109125 July 1990	Jersey Central Power & Light	New Jersey	Rate Counsel	Rate of return
95.	R-901670 July 1990	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of return Test year sales
96.	8201 October 1990	Delmarva Power & Light Company	Maryland	Depart. Natural Resources	Competitive Bidding, Resource Planning
97.	EL90-45-000 April 1991	Entergy Services, Inc.	FERC	Louisiana PSC	Rate of return
98.	GR90080786J January 1991	New Jersey Natural Gas	New Jersey	Rate Counsel	Rate of return

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99.	90-256 January 1991	South Central Bell Telephone Co.	Kentucky	Attorney General	Rate of return
100.	U-17949A February 1991	South Central Bell Telephone Co.	Louisiana	Louisiana PSC	Rate of return
101.	ER90091090J April 1991	Atlantic City Electric Company	New Jersey	Rate Counsel	Rate of return
102.	8241, Phase I April 1991	Baltimore Gas & Electric Co.	Maryland	Dept. of Natural Resources	Environmental controls
103.	8241, Phase II May 1991	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	Need for Power, Resource Planning
104.	39128 May 1991	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of return, rate base, financial planning
105.	P-900485 May 1991	Duquesne Light Company	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
106.	G900240 P910502 May 1991	Metropolitan Edison Co. Pennsylvania Electric Co.	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
107.	GR901213915 May 1991	Elizabethtown Gas Co.	New Jersey	Rate Counsel	Rate of return
108.	91-5032 August 1991	Nevada Power Co.	Nevada	U.S. Dept. of Energy	Rate of return
109.	EL90-48-000 November 1991	Entergy Services	FERC	Louisiana PSC	Capacity transfer
110.	000662 September 1991	Southwestern Bell Telephone	Oklahoma	Attorney General	Rate of return
111.	U-19236 October 1991	Arkansas Louisiana Gas Company	Louisiana	Louisiana PSC Staff	Rate of return
112.	U-19237 December 1991	Louisiana Gas Service Company	Louisiana	Louisiana PSC Staff	Rate of return

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113.	ER91030356J October 1991	Rockland Electric Company	New Jersey	Rate Counsel	Rate of return
114.	GR91071243J February 1992	South Jersey Gas Company	New Jersey	Rate Counsel	Rate of return
115.	GR91081393J March 1992	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Rate of return
116.	P-870235 et al. March 1992	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contracts
117.	8413 March 1992	Potomac Electric Power Company	Maryland	Dept. of Natural Resources	IPP purchased power contracts
118.	39236 March 1992	Indianapolis Power & Light Company	Indiana	Utility Consumer Counselor	Least-cost planning Need for power
119.	R-912164 April 1992	Equitable Gas Company	Pennsylvania	Office of Consumer Advocate	Rate of return
120.	ER-91111698J May 1992	Public Service Electric & Gas Company	New Jersey	Rate Counsel	Rate of return
121.	U-19631 June 1992	Trans Louisiana Gas Company	Louisiana	PSC Staff	Rate of return
122.	ER-91121820J July 1992	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Rate of return
123.	R-00922314 August 1992	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Rate of return
124.	92-049-05 September 1992	US West Communications	Utah	Committee of Consumer Services	Rate of return
125.	92PUE0037 September 1992	Commonwealth Gas Company	Virginia	Attorney General	Rate of return
126.	EC92-21-000 September 1992	Entergy Services, Inc.	FERC	Louisiana PSC	Merger Impacts (Affidavit)

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	Docket Number	Utility	Jurisdiction	Client	Subject
127.	ER92-341-000 December 1992	System Energy Resources	FERC	Louisiana PSC	Rate of return
128.	U-19904 November 1992	Louisiana Power & Light Company	Louisiana	Staff	Merger analysis, competition competition issues
129.	8473 November 1992	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	QF contract evaluation
130.	IPC-E-92-25 January 1993	Idaho Power Company	Idaho	Federal Executive Agencies	Power supply clause
131.	E002/GR-92-1185 February 1993	Northern States Power Company	Minnesota	Attorney General	Rate of return
132.	92-102, Phase II March 1992	Central Maine Power Company	Maine	Staff	QF contracts prudence and procurements practices
133.	EC92-21-000 March 1993	Entergy Corporation	FERC	Louisiana PSC	Merger issues
134.	8489 March 1993	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	Power plant certification
135.	11735 April 1993	Texas Electric Utilities Company	Texas	Federal Executives Agencies	Rate of return
136.	2082 May 1993	Providence Gas Company	Rhode Island	Division of Public Utilities	Rate of return
137.	P-00930715 December 1993	Bell Telephone Co. of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of return, financial projections, Bell/TCI merger
138.	R-00932670 February 1994	Pennsylvania-American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of return
139.	8583 February 1994	Conowingo Power Co.	Maryland	Dept. of Natural Resources	Competitive bidding for power supplies
140.	E-015/GR-94-001 April 1994	Minnesota Power & Light Co.	Minnesota	Attorney General	Rate of return

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	Docket Number	Utility	Jurisdiction	Client	Subject
141.	CC Docket No. 94-1 May 1994	Generic Telephone	FCC	MCI Comm. Corp.	Rate of return
142.	92-345, Phase II June 1994	Central Maine Power Co.	Maine	Advocacy Staff	Price Cap Regulation Fuel Costs
143.	93-11065 April 1994	Nevada Power Co.	Nevada	Federal Executive Agencies	Rate of return
144.	94-0065 May 1994	Commonwealth Edison Co.	Illinois	Federal Executive Agencies	Rate of return
145.	GR94010002J June 1994	South Jersey Gas Co.	New Jersey	Rate Counsel	Rate of return
146.	WR94030059 July 1994	New Jersey-American Water Co.	New Jersey	Rate Counsel	Rate of return
147.	RP91-203-000 June 1994	Tennessee Gas Pipeline Company	FERC	Customer Group	Environmental Externalities (oral testimony only)
148.	ER94-998-000 July 1994	Ocean State Power	FERC	Boston Edison Co.	Rate of return
149.	R-00942986 July 1994	West Penn Power Co.	Pennsylvania	Office of Consumer Advocate	Rate of return, emission allowances
150.	94-121 August 1994	South Central Bell Telephone Co.	Kentucky	Attorney General	Rate of return
151.	35854-S2 November 1994	PSI Energy, Inc.	Indiana	Utility Consumer Counsel	Merger savings and allocations
152.	IPC-E-94-5 November 1994	Idaho Power Co.	Idaho	Federal Executive Agencies	Rate of return
153.	November 1994	Edmonton Water	Alberta, Canada	Regional Customer Group	Rate of return (rebuttal only)
154.	90-256 December 1994	South Central Bell Telephone Co.	Kentucky	Attorney General	Incentive Plan True-Ups

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155.	U-20925 February 1995	Louisiana Power & Light Company	Louisiana	PSC Staff	Rate of return Industrial contracts Trust fund earnings
156.	R-00943231 February 1995	Pennsylvania-American Water Company	Pennsylvania	Consumer Advocate	Rate of return
157.	8678 March 1995	Generic	Maryland	Dept. Natural Resources	Electric Competition Incentive Regulation (oral only)
158.	R-000943271 April 1995	Pennsylvania Power & Light Company	Pennsylvania	Consumer Advocate	Rate of return Nuclear decommissioning Capacity Issues
159.	U-20925 May 1995	Louisiana Power & Light Company	Louisiana	Commission Staff	Class cost of service issues
160.	2290 June 1995	Narragansett Electric Company	Rhode Island	Division Staff	Rate of return
161.	U-17949E June 1995	South Central Bell Telephone Company	Louisiana	Commission Staff	Rate of return
162.	2304 July 1995	Providence Water Supply Board	Rhode Island	Division Staff	Cost recovery of capital spending program
163.	ER95-625-000 et al. August 1995	PSI Energy, Inc.	FERC	Office of Utility Consumer Counselor	Rate of return
164.	P-00950915 et al. September 1995	Paxton Creek Cogeneration Assoc.	Pennsylvania	Office of Consumer Advocate	Cogeneration contract amendment
165.	8702 September 1995	Potomac Edison Company	Maryland	Dept. of Natural Resources	Allocation of DSM Costs (oral only)
166.	ER95-533-001 September 1995	Ocean State Power	FERC	Boston Edison Co.	Cost of equity
167.	40003 November 1995	PSI Energy, Inc.	Indiana	Utility Consumer Counselor	Rate of return Retail wheeling

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168.	P-55, SUB 1013 January 1996	BellSouth	North Carolina	AT&T	Rate of return
169.	P-7, SUB 825 January 1996	Carolina Tel.	North Carolina	AT&T	Rate of return
170.	February 1996	Generic Telephone	FCC	MCI	Cost of capital
171.	95A-531EG April 1996	Public Service Company of Colorado	Colorado	Federal Executive Agencies	Merger issues
172.	ER96-399-000 May 1996	Northern Indiana Public Service Company	FERC	Indiana Office of Utility Consumer Counselor	Cost of capital
173.	8716 June 1996	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	DSM programs
174.	8725 July 1996	BGE/PEPCO	Maryland	Md. Energy Admin.	Merger Issues
175.	U-20925 August 1996	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of return Allocations Fuel Clause
176.	EC96-10-000 September 1996	BGE/PEPCO	FERC	Md. Energy Admin.	Merger issues competition
177.	EL95-53-000 November 1996	Entergy Services, Inc.	FERC	Louisiana PSC	Nuclear Decommissioning
178.	WR96100768 March 1997	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Cost of Capital
179.	WR96110818 April 1997	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Cost of Capital
180.	U-11366 April 1997	Ameritech Michigan	Michigan	MCI	Access charge reform/financial condition
181.	97-074 May 1997	BellSouth	Kentucky	MCI	Rate Rebalancing financial condition

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182.	2540 June 1997	New England Power	Rhode Island	PUC Staff	Divestiture Plan
183.	96-336-TP-CSS June 1997	Ameritech Ohio	Ohio	MCI	Access Charge reform Economic impacts
184.	WR97010052 July 1997	Maxim Sewerage Corp.	New Jersey	Ratepayer Advocate	Rate of Return
185.	97-300 August 1997	LG&E/KU	Kentucky	Attorney General	Merger Plan
186.	Case No. 8738 August 1997	Generic (oral testimony only)	Maryland	Dept. of Natural Resources	Electric Restructuring Policy
187.	Docket No. 2592 September 1997	Eastern Utilities	Rhode Island	PUC Staff	Generation Divestiture
188.	Case No.97-247 September 1997	Cincinnati Bell Telephone	Kentucky	MCI	Financial Condition
189.	Docket No. U-20925 November 1997	Entergy Louisiana	Louisiana	PSC Staff	Rate of Return
190.	Docket No. D97.7.90 November 1997	Montana Power Co.	Montana	Montana Consumers Counsel	Stranded Cost
191.	Docket No. EO97070459 November 1997	Jersey Central Power & Light Co.	New Jersey	Ratepayer Advocate	Stranded Cost
192.	Docket No. R-00974104 November 1997	Duquesne Light Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
193.	Docket No. R-00973981 November 1997	West Penn Power Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
194.	Docket No. A-1101150F0015 November 1997	Allegheny Power System DQE, Inc.	Pennsylvania	Office of Consumer Advocate	Merger Issues
195.	Docket No. WR97080615 January 1998	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Rate of Return

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196.	Docket No. R-00974149 January 1998	Pennsylvania Power Company	Pennsylvania	Office of Consumer Advocate	Stranded Cost
197.	Case No. 8774 January 1998	Allegheny Power System DQE, Inc.	Maryland	Dept. of Natural Resources MD Energy Administration	Merger Issues
198.	Docket No. U-20925 (SC) March 1998	Entergy Louisiana, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
199.	Docket No. U-22092 (SC) March 1998	Entergy Gulf States, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
200.	Docket Nos. U-22092 (SC) and U-20925(SC) May 1998	Entergy Gulf States and Entergy Louisiana	Louisiana	Commission Staff	Standby Rates
201.	Docket No. WR98010015 May 1998	NJ American Water Co.	New Jersey	Ratepayer Advocate	Rate of Return
202.	Case No. 8794 December 1998	Baltimore Gas & Electric Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
203.	Case No. 8795 December 1998	Delmarva Power & Light Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
204.	Case No. 8797 January 1998	Potomac Edison Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
205.	Docket No. WR98090795 March 1999	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Rate of Return
206.	Docket No. 99-02-05 April 1999	Connecticut Light & Power	Connecticut	Attorney General	Stranded Costs
207.	Docket No. 99-03-04 May 1999	United Illuminating Company	Connecticut	Attorney General	Stranded Costs
208.	Docket No. U-20925 (FRP) June 1999	Entergy Louisiana, Inc.	Louisiana	Staff	Capital Structure
209.	Docket No. EC-98-40-000 et. al. May 1999	American Electric Power/ Central & Southwest	FERC	Arkansas PSC	Market Power Mitigation

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210.	Docket No. 99-03-35 July 1999	United Illuminating Company	Connecticut	Attorney General	Restructuring
211.	Docket No. 99-03-36 July 1999	Connecticut Light & Power Co.	Connecticut	Attorney General	Restructuring
212.	WR99040249 Oct. 1999	Environmental Disposal Corp.	New Jersey	Ratepayer Advocate	Rate of Return
213.	2930 Nov. 1999	NEES/EUA	Rhode Island	Division Staff	Merger/Cost of Capital
214.	DE99-099 Nov. 1999	Public Service New Hampshire	New Hampshire	Consumer Advocate	Cost of Capital Issues
215.	00-01-11 Feb. 2000	Con Ed/NU	Connecticut	Attorney General	Merger Issues
216.	Case No. 8821 May 2000	Reliant/ODEC	Maryland	Dept. of Natural Resources	Need for Power/Plant Operations
217.	Case No. 8738 July 2000	Generic	Maryland	Dept. of Natural Resources	DSM Funding
218.	Case No. U-23356 June 2000	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Fuel Prudence Issues Purchased Power
219.	Case No. 21453 et. al July 2000	SWEPCO	Louisiana	PSC Staff	Stranded Costs
220.	Case No. 20925 (B) July 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
221.	Case No. 24889 August 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
222.	Case No. 21453 et. al. February 2001	CLECO	Louisiana	PSC Staff	Stranded Costs
223.	P-00001860 and P-0000181 March 2001	GPU Companies	Pennsylvania	Office of Consumer Advocate	Rate of Return

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224.	CVOL-0505662-S March 2001	ConEd/NU	Connecticut Superior Court	Attorney General	Merger (Affidavit)
225.	U-20925 (SC) March 2001	Entergy Louisiana	Louisiana	PSC Staff	Stranded Costs
226.	U-22092 (SC) March 2001	Entergy Gulf States	Louisiana	PSC Staff	Stranded Costs
227.	U-25533 May 2001	Entergy Louisiana/ Gulf States	Louisiana Interruptible Service	PSC Staff	Purchase Power
228.	P-00011872 May 2001	Pike County Pike	Pennsylvania	Office of Consumer Advocate	Rate of Return
229.	8893 July 2001	Baltimore Gas & Electric Co.	Maryland	MD Energy Administration	Corporate Restructuring
230.	8890 September 2001	Potomac Electric/Conectiv	Maryland	MD Energy Administration	Merger Issues
231.	U-25533 August 2001	Entergy Louisiana / Gulf States	Louisiana	Staff	Purchase Power Contracts
232.	U-25965 November 2001	Generic	Louisiana	Staff	RTO Issues
233.	3401 March 2002	New England Gas Co.	Rhode Island	Division of Public Utilities	Rate of Return
234.	99-833-MJR April 2002	Illinois Power Co.	U.S. District Court	U.S. Department of Justice	New Source Review
235.	U-25533 March 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Nuclear Uprates Purchase Power
236.	P-00011872 May 2002	Pike County Power & Light	Pennsylvania	Consumer Advocate	POLR Service Costs
237.	U-26361, Phase I May 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Purchase Power Cost Allocations
238.	R-00016849C001 et al. June 2002	Generic	Pennsylvania	Pennsylvania OCA	Rate of Return

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239.	U-26361, Phase II July 2002	Entergy Louisiana/ Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
240.	U-20925(B) August 2002	Entergy Louisiana	Louisiana	PSC Staff	Tax Issues
241.	U-26531 October 2002	SWEPCO	Louisiana	PSC Staff	Purchase Power Contract
242.	8936 October 2002	Delmarva Power & Lt.	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
243.	U-25965 November 2002	SWEPCO/AEP	Louisiana	PSC Staff	RTO Cost/Benefit
244.	8908 Phase I November 2002	Generic	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
245.	02S-315EG November 2002	Public Service Co. of Colorado	Colorado	Fed. Executive Agencies	Rate of Return
246.	EL02-111-000 December 2002	PJM/MISO	FERC	MD PSC	Transmission Ratemaking
247.	02-0479 February 2003	Commonwealth Edison	Illinois	Dept. of Energy	POLR Service
248.	PL03-1-000 March 2003	Generic	FERC	NASUCA	Transmission Pricing (Affidavit)
249.	U-27136 April 2003	Entergy Louisiana	Louisiana	Staff	Purchase Power Contracts
250.	8908 Phase II July 2003	Generic	Maryland	Energy Admin. Dept. of Natural Resources	Standard Offer Service
251.	U-27192 June 2003	Entergy Louisiana and Gulf States	Louisiana	LPSC Staff	Purchase Power Contract Cost Recovery
252.	C2-99-1181 October 2003	Ohio Edison Co.	U.S. District Court	U.S. Department of Justice et. al.	Clean Air Act Compliance Economic Impact (Report)
253.	RP03-398-000 December 2003	Northern Natural Gas Co.	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return

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254.	8738 December 2003	Generic	Maryland	Energy Admin Department of Natural Resources	Environmental Disclosure (oral only)
255.	U-27136 December 2003	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Purchase Power Contracts
256.	U-27192, Phase II October/December 2003	Entergy Louisiana & Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
257.	WC Docket 03-173 December 2003	Generic	FCC	MCI	Cost of Capital (TELRIC)
258.	ER 030 20110 January 2004	Atlantic City Electric	New Jersey	Ratepayer Advocate	Rate of Return
259.	E-01345A-03-0437 January 2004	Arizona Public Service Co.	Arizona	Federal Executive Agencies	Rate of Return
260.	03-10001 January 2004	Nevada Power Co.	Nevada	U.S. Dept. of Energy	Rate of Return
261.	R-00049255 June 2004	PPL Elec. Utility	Pennsylvania	Office of Consumer Advocate	Rate of Return
262.	U-20925 July 2004	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of Return Capacity Resources
263.	U-27866 September 2004	Southwest Electric Power Co.	Louisiana	PSC Staff	Purchase Power Contract
264.	U-27980 September 2004	Cleco Power	Louisiana	PSC Staff	Purchase Power Contract
265.	U-27865 October 2004	Entergy Louisiana, Inc. Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contract
266.	RP04-155 December 2004	Northern Natural Gas Co.	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return
267.	U-27836 January 2005	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Power plant purchase and cost recovery
268.	U-199040 et al. February 2005	Entergy Gulf States/ Louisiana	Louisiana	PSC Staff	Global Settlement, Multiple rate proceedings

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269.	EF03070532 March 2005	Public Service Electric and Gas	New Jersey	Ratepayers Advocate	Securitization of Deferred Costs
270.	05-0159 June 2005	Commonwealth Edison	Illinois	Department of Energy	POLR Service
271.	U-28804 June 2005	Entergy Louisiana	Louisiana	LPSC Staff	QF Contract
272.	U-28805 June 2005	Entergy Gulf States	Louisiana	LPSC Staff	QF Contract