BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of

PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY. DOCKET NO. 050045-EI

2005 COMPREHENSIVE DEPRECIATION STUDY BY FLORIDA POWER & LIGHT COMPANY. DOCKET NO. 050188-EI

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PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN BRAULIO L. BAEZ COMMISSIONER J. TERRY DEASON COMMISSIONER RUDOLPH "RUDY" BRADLEY COMMISSIONER LISA POLAK EDGAR
DATE:	Monday, August 22, 2005
TIME:	Commenced at 9:55 a.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	LINDA BOLES, RPR, CRR Official FPSC Hearings Reporter (850) 413-6734
APPEARANCES:	(As heretofore noted.)

I N D E X

WITNESSES

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF WILLIAM E. AVERA

DOCKET NO. 050045-EI

MARCH 22, 2005

Q. Please state your name and business address.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

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

A. I am a principal in Financial Concepts and Applications, Inc. (FINCAP), a firm engaged in financial, economic, and policy consulting to business and government.

OVERVIEW

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present to the Florida Public Service Commission (FPSC) my independent assessment of the fair rate of return on common equity (ROE) for FPL's jurisdictional electric utility operations. In addition, I also examined the reasonableness of FPL's capital structure, considering both the specific risks faced by FPL and other industry guidelines.

Q. How is your testimony organized?

A. I first reviewed the operations and finances of FPL and the general conditions in the utility industry and the economy. With this as a background, I developed the principles underlying the cost of equity concept and then conducted various quantitative analyses to estimate the cost of equity for a group of reference utilities. These included discounted cash flow (DCF) analyses and risk premium methods encompassing alternative approaches and studies. From the cost of equity range indicated by my analyses, a fair rate of return on equity was selected taking into account the economic requirements and specific risks and potential challenges for FPL, as well as other factors (*e.g.*, flotation costs) that are properly considered in setting a fair rate of return on equity.

Q. Are you sponsoring an exhibit in this case?

A. Yes. I am sponsoring an exhibit consisting of twelve documents, Document WEA-1 through Document WEA-12, which are attached to my direct testimony.

Q. Please describe your educational background and professional experience.

A. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Document WEA-1.

Q. Please summarize the basis of your knowledge and conclusions concerning the issues to which you are testifying in this hearing.

A. As is common and generally accepted in my field of expertise, I have accessed and used information from a variety of sources. I am familiar with the organization, operations, finances, and operation of FPL from my participation in prior proceedings before the FPSC. In connection with the present filing, I obtained information through discussions with corporate management and from my review of numerous documents relating to FPL, including bond rating agency reports, financial filings, and prior regulatory proceedings and orders. I also reviewed information relating generally to capital markets and specifically to investor perceptions, requirements, and expectations for regulated utilities. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of FPL and are the bases for my conclusions.

Q What is the role of the return on equity in setting a utility's rates?

A. The rate of return on common equity compensates shareholders for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the United States Supreme Court in the *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n* [262 U.S. 679 (1923)] and *Fed. Power Comm'n v. Hope Natural Gas Co.* [320 U.S. 591 (1944)] cases, a utility's allowed return on common equity should be sufficient to (1) fairly compensate capital invested in the utility, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

SUMMARY OF CONCLUSIONS

Q. What are your findings regarding the fair rate of return on equity for the 2006 test year?

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital, I determined that a fair rate of return on equity for FPL is currently in the range of 11.3 to 12.3 percent, with a midpoint of 11.8 percent. The bases for my conclusion are summarized below:

- *Applications of DCF and risk premium approaches to the reference group of electric utilities implied a cost of equity in the range of 10.0 to 12.0 percent;*
- *Incorporating a 30 basis-point allowance for equity flotation costs resulted in a fair rate of return range for the electric utility proxy*

group of 10.3 to 12.3 percent;

- *Considering the potential exposures associated with FPL's resource mix and service area and the need to support FPL's ability to attract capital under adverse circumstances, I recommend a rate of return for FPL in the range of 11.3 to 12.3 percent, which corresponds to the upper half of the proxy group results.*
- *The 11.8 percent midpoint of my recommended fair rate of return on equity range does not explicitly incorporate any allowance for superior results. An incentive to recognize and encourage exemplary performance, such as that documented in the testimony of FPL's witnesses, is an appropriate consideration in establishing a fair rate of return:*
    - *Consumers in FPL's service area have benefited from efficient and cost-effective operations, excellent customer service, improved reliability, and prices that have declined in real terms;*
    - *Providing the opportunity to earn an incremental return offers an appropriate incentive for FPL to continue to innovate and take risks in pursuit of superior performance;*
    - *Incorporating the 50 basis-point ROE incentive proposed by FPL to my 11.8 percent recommended cost of equity for FPL results in a fair rate of return on equity of 12.3 percent.*

- *Finally, giving effect to the 100 basis-point range typically allowed by the FPSC for regulatory purposes results in an appropriate fair rate of return on equity range for FPL of 11.3 to 13.3 percent.*

My analyses of the cost of equity focused on a comparable group of 21 electric utilities with an average bond rating of single-A. My evaluation indicated that, after taking into account risks specific to FPL and the offsetting effect of FPL's relatively higher equity ratio, investors view FPL's overall investment risks as equivalent to those of the benchmark group of electric utilities. This conclusion was based on the following findings:

- *In evaluating FPL's relative risks, investors consider the implications of its relatively greater reliance on nuclear and purchased power, increased exposure to uncertainties regarding natural gas prices and supplies, and the characteristics of its service area economy;*
- *While these factors suggest that FPL may be somewhat riskier than the firms in the benchmark group, they are mitigated by FPL's financial strength;*
- *FPL's corporate credit rating, which provides the most objective and encompassing measure of overall investment risk, is identical to that maintained by the average firm in the electric utility proxy group.*

Q. **What is your conclusion as to the reasonableness of FPL's capital structure?**

A. Based on my evaluation, I concluded that the approximately 55 percent common equity ratio (as adjusted for off balance sheet obligations) maintained by FPL represents a reasonable mix of capital sources from which to calculate FPL's overall rate of return. This conclusion was based on the following findings:

- *While FPL's adjusted common equity ratio falls above the average maintained by the electric utility operating companies contained in the proxy group, it is well within the range of individual results for these firms and in-line with the lower leverage expected for the industry going forward;*
- *While FPL's total debt ratio is slightly above rating agency guidelines for a single-A rating, this relatively conservative financial posture has not been sufficient to warrant an upgrade to FPL's credit standing, with S&P continuing to maintain a "negative" outlook, warning investors of the potential for further deterioration;*
- *Absent its relatively conservative capital structure, FPL's debt rating would undoubtedly be lower than present levels and the resulting greater investment risk would imply an increase in investors' required rate of return for FPL's securities;*
- *For an electric utility with an obligation to provide reliable service, uncertainties associated with FPL's resource mix and service area highlight the necessity of preserving flexibility, even during periods of adverse capital market conditions.*

Considering investors' heightened awareness of the risks associated with the electric power industry and the damage that results when a utility's financial flexibility is compromised, supportive regulation is perhaps more crucial now than at any time in the past. Indeed, the investment community is intensely focused on the actions of the FPSC, and if FPL's ongoing request to recover storm repair costs in Docket No. 041291-EI were to be denied, this would imply a significant increase in investment risk and required rate of return, and my recommended ROE would need to be adjusted upward accordingly. The cost of providing FPL an adequate return is small relative to the potential benefits of having a financially sound utility that can provide reliable service at reasonable rates and a platform for economic growth; especially when compared against the extreme burden imposed by a financially troubled service provider.

FUNDAMENTAL ANALYSES

Q. What is the purpose of this section?

A. As a predicate to subsequent quantitative analyses, this section briefly reviews FPL's operations and finances. In addition, it examines the risks and prospects for the electric utility industry and conditions in the capital markets and the general economy. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion of investors' expectations and requirements, and form the basis of a fair rate of return.

Florida Power & Light Company

Q. Briefly describe FPL and its parent, FPL Group, Inc.

A. Headquartered in Juno Beach, Florida, FPL is engaged in the generation, transmission, and distribution of electric power throughout 34 counties located principally along the east and lower west coasts of Florida. FPL's service territory includes a population of more than 8 million, with service being provided to approximately 4.2 million customers. FPL is the principal subsidiary of FPL Group, Inc. (FPL Group). In addition to the electric utility operations of FPL, FPL Group is involved in the development, construction, and management of independent power generation facilities through FPL Energy, LLC. Through a subsidiary, FPL Energy buys and sells wholesale energy commodities, such as natural gas, oil and electric power and owns and operates a fiber-optic network that interconnects major cities within Florida (FPL FiberNet, LLC). As of December 31, 2004, FPL Group had total assets of approximately $28.3 billion, with consolidated revenues totaling approximately $10.5 billion for the most recent fiscal year.

Q. Please describe FPL's electric utility operations.

A. In addition to an economic base dominated by tourism, principal industries in FPL's service area include agriculture, manufacturing, and international trade. FPL employs approximately 10,000 individuals, with energy sales amounting to over 103 million megawatt hours during 2004. Approximately 51 percent of 2004 retail electric revenues were attributable to residential customers, with 41 percent from commercial and 4 percent from industrial users. With a combined capacity of approximately 18,940 megawatts (MW), FPL's generating facilities include the four nuclear units of the St. Lucie and Turkey Point generating stations, with a total capacity of 2,939 MW. In 2004, nuclear generation accounted for 21 percent of the electric energy provided by FPL, with natural gas at 37 percent, oil at 18 percent, and coal at 6 percent.

The remaining 18 percent of FPL's 2004 energy requirements were obtained through purchased power contracts. Take-or-pay purchased power contracts with the Jacksonville Electric Authority (JEA) and with subsidiaries of The Southern Company (Southern Company) provide approximately 1,300 MW of power through mid-2015 and 381 MW thereafter through 2021. FPL also has various firm contracts to purchase approximately 900 MW of capacity and energy from certain cogenerators and qualifying facilities. In addition, FPL has various agreements with several other electricity suppliers to purchase an aggregate of up to approximately 1,900 MW of power with expiration dates ranging from 2005 through 2009. FPL estimates that capacity and minimum payments under these agreements will average approximately $640 million annually through 2009.

FPL's transmission and distribution facilities consist of over 500 substations and include almost 47,000 miles of overhead lines and approximately 24,300 miles of underground and submarine cables. At December 31, 2004, FPL's investment in net utility plant was approximately $14.0 billion. Capital expenditures for the construction or acquisition of additional facilities to meet customer demand are estimated to be approximately $8.5 billion for the years 2005 through 2009.

FPL's retail electric operations are subject to the jurisdiction of the FPSC, with the interstate jurisdiction regulated by Federal Energy Regulatory Commission (FERC). Additionally, FPL's nuclear facilities are subject to licensing and oversight by the Nuclear Regulatory Commission (NRC). The operating licenses for Turkey Point Units Nos. 3 and 4 received extensions in 2002, which gives FPL the option to operate these units until 2032 and 2033, respectively. The NRC extended the operating licenses for St. Lucie Units Nos. 1 and 2 during 2003, which give FPL the option to operate these units until 2036 and 2043, respectively. FPL's latest decommissioning studies indicate that FPL's portion of the cost of decommissioning its four nuclear units, including costs associated with spent fuel storage, to be $6.4 billion. At December 31, 2004, the accumulated provision for nuclear decommissioning totaled approximately $2.2 billion.

Q. What credit ratings have been assigned to FPL?

A. FPL has been assigned an issuer credit rating of "A1" by Moody's Investors Service (Moody's), with its senior secured debt being rated "Aa3". Similarly, Fitch Ratings has assigned a long-term credit rating of "A+" to FPL, while rating its first mortgage bonds "AA-". Standard & Poor's Corporation (S&P), meanwhile, has assigned FPL an "A" rating with a negative outlook, indicating the possibility of a further reduction in FPL's credit standing going forward.

Electric Utility Industry

Q. What are the general conditions in the electric utility industry?

A. The industry is characterized by structural changes resulting from market forces, deregulation initiatives, and judicial decisions.

Q. Please describe these structural changes.

A. At the federal level, the FERC has been an aggressive proponent of regulatory driven reforms designed to foster greater competition in markets for wholesale power supply. The National Energy Policy Act of 1992, which reformed both the Public Utility Holding Company Act of 1935 and the Federal Power Act, greatly increased prospective competition for the production and sale of power at the wholesale level. In April 1996, FERC adopted Order No. 888, mandating "open access" to the transmission facilities of jurisdictional electric utilities. FERC also has pushed for the regionalization of transmission system control by establishing frameworks for creation of RTOs in its Order No. 2000 [*Regional Transmission Organizations*, Order No. 2000 (Dec. 20, 1999), 89 FERC ¶ 61,285]. In 2002 FERC issued a notice of proposed rulemaking proposing a framework to address alleged discrimination in providing interstate transmission services and in other industry practices.

Subsequently, in April 2003 FERC issued a White Paper refining its vision for a wholesale power market platform, taking into account developments in market design and comments filed in response to the earlier SMD NOPR [FERC White Paper, *Wholesale Power Market Platform,* April 28, 2003]. "Open access" has, in the view of most market observers, resulted in more competition and competitors in wholesale power markets, but not without the introduction of substantial risks – particularly for utilities that depend on wholesale power markets for a portion of their resource requirements.

Q. What impact did the western power crisis have on investors' risk perceptions for firms involved in the electric power industry?

A. Events of last several years caused investors to rethink their assessment of the relative risks associated with the electric power industry. A well-publicized energy crisis throughout the west wreaked havoc on the customers, utilities, and policymakers. It also had dramatic repercussions for western wholesale power markets and investors and utilities nationwide. State regulators and legislators have re-evaluated restructuring initiatives for the retail sector of the electric industry and the financial implications of the western power crisis experience demonstrated the risks facing all segments of the electric power industry.

The massive debts owed by California's retail utilities to banks, power producers and other creditors shattered their financial integrity and the subsequent bankruptcy filing of Pacific Gas and Electric Company (PG&E) brought the uncertainties associated with today's power markets into sharp focus for the investment community. Enron's, and later Mirant Corporation's, bankruptcies only served to magnify the risks associated with the power sector and increased investors' reluctance to commit capital in the energy industry, as former FERC Commissioner Massey succinctly recognized:

> Investor confidence has been shaken by these events, by a declining national economy, indictments of energy traders, accounting irregularities, downgrades by rating agencies, and continuing investigations by the FERC, CFTC, the SEC, and the Justice Department. ...The flight of capital from the industry has been severe since the collapse of Enron. [*Remarks by William L. Massey*, Center for Public Utilities Advisory Council, "The Santa Fe Conference" (March 17, 2003)]

While the case of California and PG&E represents an extreme example, there is every indication that investors' risk perceptions for electric utilities shifted sharply upward in response to events in the western U.S..

Q. What was the impact of these capital and credit market conditions on the ability of electric utilities to raise funds?

A. Combined with economic and global uncertainties, the dramatic upward shift in investors' risk perceptions and the weakened financial picture of most industry participants, combined to produce a severe liquidity crunch in the electric power industry. S&P cited the debilitating impact of these developments on investors' willingness to provide capital:

> The last 24 months have witnessed extraordinary turmoil for power and energy debt, unprecedented since Samuel Insull's utility empire collapsed during the 1930s. Events ranging from the credit collapse of the California utilities, through the Enron bankruptcy and subsequent

> market disruptions for U.S. energy merchant companies have destroyed billions of dollars of value for investors. Wall Street has virtually shut down new investment in this sector. ["U.S. Power Industry Experiences Precipitous Credit Decline in 2002; Negative Slope Likely to Continue", *RatingsDirect* (Jan. 15, 2003)]

S&P went on to recognize that the end result of investors' waning confidence in the industry led to reduced access to capital:

> Increasingly constrained capital market access as a result of investor skepticism over accounting practices and disclosure, more and more federal and state investigations and subpoenas, audits, and failing confidence in future financial performance has created a liquidity crisis.

The challenges faced by electric utilities resulted in reduced financing activity, with many utilities being forced to rely on bank debt. Access to the commercial paper markets, long the low-cost staple of high-grade utilities for meeting working capital needs, virtually disappeared for certain companies. S&P went on to note that the falloff in financing activity was partly attributable to "capital market jitters, especially for those firms that are most in need of capital market access." As a result, at the same time that industry uncertainty and market volatility increased the importance of financial flexibility, S&P observed in a July 24, 2003 report that constrained access to capital markets and investor skepticism was contributing to the bleak credit picture.

Q. How were western utilities impacted by conditions in the electric power industry?

A. The financial integrity of many utilities in the region was severely damaged by the maelstrom of the western energy crisis. While a full description of the western power crisis and its effects is beyond the scope of this testimony, the chaotic market conditions were felt directly and with full force. Utilities were forced to use cash flows from operations, various bank borrowings, and short- and long-term debt to fund unrecovered energy supply costs. This led to a sharp deterioration in financial condition, a severe liquidity crunch, and a dramatic increase in credit risk. As a result, commercial banks were highly reticent to extend financing for ongoing operations or new construction and counterparties involved in meeting the utilities' energy needs became unwilling to transact business absent special credit terms. To varying degrees, utilities throughout the western U.S. were confronted with the difficult task of maintaining reliable service and financial integrity in a power market characterized by short supply and unprecedented price volatility.

Even for electric utilities like FPL that have permanent fuel and purchased power adjustment mechanisms in place, there can be a significant lag between the time the utility actually incurs the expenditure and when it is recovered from customers. One example of the risk of regulatory lag was noted by The Value Line Investment Survey (Value Line) in a November 17, 2000 report:

> **A lag in the recovery of sharply higher power costs is hurting Sierra Pacific Resources.** Power prices in the West have soared since the second quarter of 2000, and until recently, SPR's two utilities lacked a mechanism for recovering these increases. The Nevada

> Commission has granted one, but it won't solve the utilities' problem right away. That's because the mechanism tracks power costs over a trailing 12-month period and because the amount by which the utilities can raise rates each month is capped.

The continuing prospect of further challenges in power markets cannot be discounted, with S&P reporting continued spikes in wholesale market prices:

> For 2003, record-high wholesale power prices were the defining feature of the U.S. merchant power markets. ...Power prices across the U.S. continent generally rose on the order of 50% or more in 2003. ...Prices in the western regions were also the highest on record outside of the 2000-2001 California energy crisis. ["Energy Commodity Report: U.S. Power Prices Record High in 2003," *RatingsDirect* (Jan. 15, 2004)]

Investors recognize that volatile markets and inopportune reliance on wholesale purchases to meet resource needs can constitute a dangerous combination, exposing the utility to the risk of reduced cash flows and unrecovered power supply costs.

Q. What are the implications of the power outages experienced in the upper Midwest and Northeast during August 2003?

A. These events underscore the continuing risks inherent in the industry and the uncertain state of affairs with respect to the industry's structure. The massive blackout, which stretched from New York to Detroit and from Ohio into Canada, was the largest power outage in U.S. history. This event sharpened the focus of industry stakeholders – utilities, consumers, regulators, and investors – on the need to improve the nation's electricity infrastructure, especially in light of the additional stress that deregulated wholesale markets have placed on the network. The importance of rapidly stimulating investment in electric power infrastructure has been almost universally cited as the key to ensuring that further outages are avoided. As FERC Chairman Wood noted in an August 15, 2003 press release:

> If we draw any conclusions from this blackout, it is the urgent need for more investment in the nation's transmission grid to serve broad regional needs.

Q. Have these events affected utilities' credit standing?

A. Yes. The last several years have witnessed steady erosion in credit quality throughout the utility industry, both as a result of revised perceptions of the risks in the industry and the weakened finances of the utilities themselves. For example, in its January 15, 2003 edition of *RatingsDirect,* S&P noted that it had recorded 182 downgrades in the utility industry during 2002, versus only 15 upgrades, while Moody's reported in its July 14, 2003 *Credit Perspectives* that it had downgraded 109 utility issuers and upgraded only 3 – an acceleration of the trend in bond rating changes during the previous two years. Moreover, credit quality continued to decline during 2003. S&P observed the utility industry "continued its downward credit slide that began in early 2000," reporting 139 downgrades during 2003, compared with just 8 upgrades, with downgrades outpacing upgrades by more than 15 to one in the fourth quarter of 2003 [*RatingsDirect*, Jan. 29, 2004]. While the pace and scale of negative ratings actions has since diminished, S&P reported that 44 percent of the utility sector now falls in the triple-B rating category, with 20 percent of issuers being rated below this investment grade threshold, and noted little likelihood for any significant upturn in credit outlook [*RatingsDirect*, Jul. 29, 2004].

Q. Are all of the risks associated with the restructuring of the electric industry known at this time?

A. No. My experience with deregulation in the transportation and natural gas industries demonstrates that the structural changes associated with deregulation produces consequences that no one can predict. As prices become primarily market-driven, future changes in prices become inherently uncertain. Much of this uncertainty simply reflects the superior ability of markets to adjust continually both to changing customer needs and to the changing costs of meeting those needs. This point was succinctly stated in the 1997 *Economic Report of the President*:

> An insufficiently appreciated property of markets is their ability to collect and distribute information on costs and benefits in a way that enables buyers and sellers to make effective, responsive decisions. ...As tastes, technology, and resource availability change, market prices will change in corresponding ways to direct resources to the newly valued ends and away from obsolete means. It is simply impossible for governments to duplicate and utilize the massive amount of information exchanged and acted upon daily by the millions of participants in the marketplace. (p. 191)

If structural evolution in the electric utility industry ultimately provides benefits for both consumers and producers, these benefits come at a cost. Namely, all participants will become exposed to new uncertainties, such as the threat of new entrants and technologies and the threat of price volatility in wholesale markets. It will be the challenge of regulators and policymakers to establish markets that capture the benefits of competition for consumers while mitigating the impacts of its inherent risks.

Q. Are investors likely to consider the impact of market restructuring in assessing their required rate of return for FPL?

A. Absolutely. While restructuring of the electric utility industry has not been implemented in Florida, the final report of the Energy 2020 Study Commission established by the Governor identified the transition to an effective competitive wholesale generation market as one objective, along with encouraging the development of merchant power plants. Similarly, the FPSC has announced that it favors an eventual transition to effective competition in the wholesale power market. While investors recognize that potential wholesale competitors could find FPL's market attractive, deregulation of electric generation will ultimately require legislative action, which is not considered likely in the near-term.

Despite the fact that electric utilities in Florida continue to operate in a regulated environment, FPL nevertheless faces the prospect of changes in the transmission function of their business, as well as more fundamental reforms in how utilities operate to optimize their assets for the benefit of retail customers. Policy evolution in the transmission area has been wide-reaching and investors' focus on regulatory change in their assessment of risks and prospects was exemplified by S&P's remarks in "Electric Transmission at the Starting Gate", *RatingsDirect* (May 10, 2002):

> The FERC is in the process of changing every aspect of the electric utility landscape, with industry sages anticipating further transmission and wholesale market development guidance, which could affect the

> segment's credit prospects and quality. ...Significant uncertainty still exists for transmission companies that may operate under an RTO or ISO structure, which will significantly impact the full scope of capital expenditures necessary to ensure reliability and increase capacity in the future. Uncertainty will exist until operating rules are in place and have stabilized.

Virtually all industry stakeholders have recognized that regulatory uncertainties increase the risks associated with the electric industry. Former FERC Commissioner Massey has noted that regulatory uncertainty is "part of the problem" explaining under-investment in electric utility infrastructure [9th Annual Spring Conference for the New England Energy Industry (May 21, 2002)] The Department of Energy (DOE) identified "reducing regulatory uncertainty" as critical in stimulating increased investment in the power industry and has noted that lack of clarity in the regulatory structure was inhibiting planning and investment [*National Transmission Grid Study* (May 2002)]. The DOE also recognized the impact that this regulatory uncertainty has on investors' required rates of return for electric utilities:

> Because transmission assets are long lived, regulatory uncertainty increases the risks to investors and, therefore, increases the returns they need to justify transmission system investments.

Q. Is there any indication that the importance of these considerations have diminished in the eyes of investors?

A. No. The 2003 blackout only served to reinforce the importance of regulatory risks for investors. The Wall Street Journal ["Overloaded Circuits Blackout Signals Major Weakness in U.S. Power Grid," The Wall Street Journal (Aug. 18, 2003)] cited the debilitating impact of an "unsteady regulatory environment" and the "chaotic combination of regulated and deregulated markets" in explaining inhibitions to increased investment in the electric utility system. Similarly, in an August 21, 2003 comment on the blackout, S&P warned investors that the partial reforms presently characterizing wholesale power markets invites dysfunction and that elevated risks will discourage new capital, "or at least make it more expensive." S&P observed:

> Investors should not expect that such risk will dissipate any time soon. Instead, credit risk could actually intensify if the politically charged debate over reform continues for years, as it might very well do. And even if policy makers succeed in crafting a comprehensive solution to the problems of the nation's energy grid, the regulatory treatment of the costs needed to upgrade the infrastructure remains uncertain.

Even before the establishment of any transition to competition, market trends and federal policies will continue to impact FPL and its investors. Moreover, as the Energy 2020 Study Commission recognized in its February 2001 *Interim Report*, lack of restructuring legislation does not leave industry stakeholders immune from adversity, concluding that "[t]he environment … will be replete with uncertainty and risk." Because of potential exposure to wholesale markets, the risks of transmission uncertainties and potential market volatility are intensified for utilities that depend heavily on purchased power. Reliance on purchased power to meet resource needs or fill potential shortfalls in generation magnifies the importance of maintaining the financial flexibility necessary to fund an adequate and reliable utility system. At the same time, it also exposes utilities and their investors to the ongoing regulatory uncertainties and other risks imposed by restructuring of wholesale power markets.

Already, FPL has confronted the uncertainties associated with the establishment of regional transmission organizations (RTOs), pursuant to FERC's policy initiatives. In October 2000, together with Progress Energy Florida and Tampa Electric Company, FPL proposed the formation of an independent entity, GridFlorida, to own and operate the transmission system. Since that time, there have been numerous regulatory and legal proceedings concerning the formation of GridFlorida and the framework underlying operation and oversight of the transmission system. Thus, while a competitive wholesale market has not been implemented for FPL's service territory, investors undoubtedly consider these factors in assessing the required rate of return on long-term capital, such as common equity.

Q. Are the uncertainties associated with structural changes the only risks being faced by electric utilities?

A. No. Apart from these factors, a number of electric utilities, once considered the paragon of financial stability, have experienced difficult financial straits. In part to avoid the risks associated with building additional base-load generating capacity, electric utilities have pursued a variety of options, such as increased reliance on power purchases from wholesale suppliers and non-utility generators, although these entail additional risks in and of themselves. The industry continues to face the risks inherent in operating electric utility systems. Electric utilities are confronting increased environmental pressures that could impose significant costs on utilities that rely on coal as a boiler fuel. S&P's *Corporate Ratings Criteria* recognized the potential financial challenges posed by such uncertainties:

> Pension obligations, environmental liabilities, and serious legal problems restrict flexibility, apart from the obligations' direct financial implications.

While FPL has demonstrated leadership within its industry in protecting the environment, it remains exposed to uncertainties regarding emissions and potential contamination. Nuclear risk persists for those utilities involved in nuclear plants, although the exposure has shifted from construction to operating and decommissioning uncertainties.

Economy and Capital Markets

Q. What has been the pattern of interest rates over the last decade?

A. Average long-term public utility bond rates, the monthly average prime rate, and inflation as measured by the consumer price index since 1990 are plotted in the graph at the top of Document WEA-2. After rising to approximately 10 percent in mid-1990, the average yield on long-term public utility bonds generally fell as economic conditions weakened in the aftermath of the 1991 Gulf war, with rates dipping below 7 percent in late 1993. Yields subsequently rose again in 1994, before beginning a general decline, with investors requiring approximately 5.8 percent from average public utility bonds in January 2005.

Q. Are investors likely to anticipate any substantial decline in interest rates going forward?

A. No. While interest rates are currently at relatively low levels, investors are unlikely to expect any further significant declines going forward. The general expectation is that interest rates will begin to rise with strengthening economic growth, with Value

Line citing "the strong possibility of rising interest rates in 2005" in its December 17, 2004 report (p. 459). Indeed, the Federal Reserve on February 2, 2005 raised interest rates for the sixth time since June 2004 and signaled it was likely to continue to act at a "measured" pace. The latest quarter-point increase raised the federal funds rate to 2.5 percent, more than double the 46-year low of 1.00 percent in effect when the Fed began its credit-tightening campaign in 2004. Meanwhile, the Wall Street Journal reported (Jan. 5, 2005 at A2) expectations of a steady rise in rates:

> The minutes suggest that the Fed is less likely to pause in its interest-rate increases this year than the markets may have expected. In the wake of the minutes' release, long-term bond prices fell sharply, and yields, which move in the opposite direction, rose.

Consistent with these general expectations for higher interest rates, the most recent forecast of the Energy Information Administration (EIA), a statistical agency of the DOE, anticipates that the double-A public utility bond yield will increase from approximately 6.23 percent in 2004 to 7.07 in 2005, increasing to 7.42 percent over the next five years. [Annual Energy Outlook 2005, Table 19] Similarly, GlobalInsight (formerly DRI/WEFA), a widely referenced forecasting service, calls for double-A public utility bond yields to average 6.69 percent in 2005, reaching 7.62 percent by 2009. ["The U.S. Economy, The 25-Year Focus", Table 33 (Summer 2004)]. The February 1, 2005 edition of Blue Chip Financial Forecasts (Blue Chip) also anticipates that bond yields will rise significantly over the 2005-2006 period covered by its projections.

Q. How has the market for common equity capital performed?

A. Between 1990 and early 2000 stock prices pushed steadily higher as the longest bull market in United States history continued unabated. While the S&P 500 had increased over four times in value by August 2000, mounting concerns regarding prospects for future growth, particularly for firms in the high technology and telecommunications sectors, pushed equity prices lower, in some cases precipitously. While common stock prices have recovered strongly from their lows, the market remains volatile, with share values routinely changing in full percentage points during a single day's trading. The graph at the bottom of Document WEA-2 plots the performances of the Dow-Jones Industrial Average, the S&P 500, and the Dow Jones Utility Average since 1990 (the latter two indices were scaled for comparability).

Q. What is the outlook for the United States economy?

A. During the decade through the first quarter of 2001, the United States economy enjoyed the longest peacetime expansion in history. Monetary and fiscal policies resulted in modest inflation during this period, with unemployment rates falling to their lowest levels since the 1960s. A revolution in information technology, rising productivity, and vibrant international trade all contributed to strong economic growth. However, even before the events of September 11, 2001, there were increasing signs that the economic expansion would not be sustainable. Concerns regarding the slowing pace of economic activity were exemplified by the Federal Reserve's sequential lowering of interest rates. The economic picture has brightened more recently. Gross domestic product surged in the last half of 2003 and is expanded at roughly a 3-4 percent rate for 2004, with Florida's economy expected to outpace the nation in the near term. Manufacturing activity has rebounded and construction spending and retail sales have both increased. Nevertheless, businesses have been reluctant to expand hiring and uncertainties over the durability of the economic recovery continue to be magnified by overhanging government and trade deficits, as well as continued conflict and instability in Iraq and the ongoing threat of terrorism, which undermines consumer confidence and contributes to global economic uncertainty. These factors cause the outlook to remain tenuous, with persistent stock and bond price volatility providing tangible evidence of the uncertainties faced by the United States economy.

Q. How do these capital market uncertainties affect electric utilities?

A. Uncertainties over the extent and durability of the economic recovery have combined to heighten the risks faced by utilities. A return to stagnant economic growth would undoubtedly mean flat sales, while the potential for higher inflation and interest rates that will likely accompany the current economic rebound place additional pressure on the adequacy of existing service rates. While the national economy may ultimately return to a path of steady growth and the volatility in the capital and energy markets may abate, the underlying weaknesses now present cause considerable uncertainties to persist, which increase the risks faced by the utility industry.

CAPITAL MARKET ESTIMATES

Q. What is the purpose of this section of your testimony?

A. In this section, capital market estimates of the cost of equity are developed for a benchmark group of electric utilities. First, I examine the concept of the cost of equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF and risk premium analyses conducted to estimate the cost of equity for the reference group of electric utilities.

Economic Standards

Q. What role does the rate of return on common equity play in a utility's rates?

A. The return on common equity is the cost of inducing and retaining investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Competition for investor funds is intense and investors are free to invest their funds wherever they choose. They will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks. Moreover, the return on common equity is integral in achieving the sound regulatory objectives of rates that are sufficient to: 1) fairly compensate capital investment in the utility, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. Meeting these objectives allows the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through expansion of the electric system.

Q. What fundamental economic principle underlies this cost of equity concept?

A. Unlike debt capital, there is no contractually guaranteed return on common equity capital since shareholders are the residual owners of the utility. Nonetheless, common equity investors still require a return on their investment; with the cost of equity being the minimum "rent" that must be paid for the use of their money. This cost of equity typically serves as the starting point for determining a fair rate of return on common equity.

The cost of equity concept is predicated on the notion that investors are risk averse, and will willingly bear additional risk only if they expect compensation for doing so. In capital markets where relatively risk-free assets are available (*e.g.*, U.S.

Treasury securities) investors can be induced to hold more risky assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Since all assets compete with each other for investors' funds, more risky assets must yield a higher expected rate of return than less risky assets in order for investors to be willing to hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can be generally expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return; and

RP_i = Risk premium required to hold risky asset i.

Thus, the required rate of return for a particular asset at any point in time is a function of: 1) the yield on risk-free assets, and 2) its relative risk, with investors demanding correspondingly larger risk premiums for assets bearing greater risk.

Q. Does the risk-return tradeoff principle actually operate in the capital markets?

A. Yes. The risk-return tradeoff is readily observable in certain segments of the capital markets where required rates of return can be directly inferred from market data and generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. The observed yields on government securities, which are considered free of default risk, and bonds of various rating categories demonstrate that the risk-return tradeoff does, in fact, exist in the capital markets.

Q. Does the risk-return tradeoff observed with fixed income securities extend to common stocks and other assets?

A. It is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common stock – required rates of return cannot be directly observed. Nevertheless, it is a fundamental tenet that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed income securities. This has been supported and demonstrated by considerable empirical research in the field of finance and is confirmed by reference to historical earned rates of return, with realized rates of return on common stocks exceeding those on government and corporate bonds over the long-term.

Q. Is this risk-return tradeoff limited to differences between firms?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. Debt, preferred stock, and common equity vary considerably in risk because they have different characteristics and priorities.

When investors loan money in the form of debt (*e.g.*, long-term bonds), they enter into a contract whereby the utility agrees to pay the bondholders a specified amount of interest and to repay the principal of the loan in full. The bondholders have a senior claim on available cash flow for these payments, and if the utility fails to make them, they may force it into bankruptcy and liquidation for settlement of unpaid claims. Similarly, when a utility sells investors preferred stock, the utility promises to pay preferred stockholders specified dividends and, typically, to retire the preferred stock on a predetermined schedule. While the rights of preferred stockholders to available cash flow for these payments are junior to creditors, and preferred stockholders cannot compel bankruptcy, their claims are senior to those of common shareholders.

The last investors in line are common shareholders. They only receive the cash flow, if any, that remains after all other claimants – employees, suppliers, governments, lenders, and preferred stockholders – have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, is considerably higher than the yield on the utility's long-term debt or preferred stock, which have more certain, senior claims.

Q. What does the above discussion imply with respect to estimating the cost of equity?

A. Although the cost of equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is unobservable, the cost of equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

Q. Have you relied on a single method to estimate the cost of equity for FPL?

A. No. In my opinion, no single method or model should be relied upon to determine a utility's cost of equity because no single approach can be regarded as wholly reliable.

As the Federal Communications Commission recognized in Report and Order 42-43 (CC Docket No. 92-133, 1995):

> Equity prices are established in highly volatile and uncertain capital markets... Different forecasting methodologies compete with each other for eminence, only to be superceded by other methodologies as conditions change... In these circumstances, we should not restrict ourselves to one methodology, or even a series of methodologies, that would be applied mechanically. Instead, we conclude that we should adopt a more accommodating and flexible position.

Therefore, in addition to the DCF model, I applied the risk premium method based on data for utilities and using forward-looking estimates of required rates of return. In addition, I also evaluated my results using a comparable earnings approach based on investors' current expectations in the capital markets. In my opinion, comparing estimates produced by one method with those produced by other approaches ensures that the estimates of the cost of equity pass fundamental tests of reasonableness and economic logic.

Discounted Cash Flow Analyses

Q. How are DCF models used to estimate the cost of equity?

A. The use of DCF models is essentially an attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expected rates of return, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. In other words, the cash flows that investors expect from a stock are estimated, and given its current market price, we can "back-into" the discount rate, or cost of equity, that investors presumptively used in bidding the stock to that price.

Q. What market valuation process underlies DCF models?

A. DCF models are derived from a theory of valuation which assumes that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return, or the cost of equity. Notationally, the general form of the DCF model is as follows:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

where: P_0 = Current price per share;

P_t = Expected future price per share in period t;

D_t = Expected dividend per share in period t;

k_e = Cost of equity.

That is, the cost of equity is the discount rate that will equate the current price of a share of stock with the present value of all expected cash flows from the stock.

Q. Has this general form of the DCF model customarily been used to estimate the cost of equity in rate cases?

A. No. In an effort to reduce the number of required estimates and computational difficulties, the general form of the DCF model has been simplified to a "constant growth" form. But converting the general form of the DCF model to the constant growth DCF model requires a number of strict assumptions. These include:

- A constant growth rate for both dividends and earnings;
- A stable dividend payout ratio;
- The discount rate exceeds the growth rate;
- A constant growth rate for book value and price;
- A constant earned rate of return on book value;
- No sales of stock at a price above or below book value;
- A constant price-earnings ratio;
- A constant discount rate (i.e., no changes in risk or interest rate levels and a flat yield curve); and
- All of the above extend to infinity.

Given these assumptions, the general form of the DCF model can be reduced to the more manageable formula of:

$$P_0 = \frac{D_1}{k_e - g}$$

where: g = Investors' long-term growth expectations.

The cost of equity (K_e) can be isolated by rearranging terms:

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0), and 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q. Are the assumptions underlying the constant growth form of the DCF model met in the real world?

A. In practice, none of the assumptions required to convert the general form of the DCF model to the constant growth form are ever strictly met. Nevertheless, where earnings are derived from stable activities, and earnings, dividends, and book value track fairly closely, the constant growth form of the DCF model offers a reasonable working approximation of stock valuation that provides useful insight as to investors' required rate of return.

Q. How did you implement the DCF model to estimate the cost of equity for FPL?

A. As described above, application of the DCF model to estimate the cost of equity requires an observable stock price. Because FPL is a wholly-owned subsidiary of FPL Group and has no publicly traded stock, its cost of equity cannot be estimated directly using the DCF model. As an alternative, the cost of equity for an untraded firm is often estimated by applying the DCF model to publicly traded companies engaged in the same business activity. In order to reflect the risks and prospects associated with FPL's jurisdictional utility operations, my DCF analyses focused on a reference group of other electric utilities. This electric utility proxy group was composed of companies included in Value Line's Electric Utilities Industry group with an S&P corporate credit rating of "BBB+" or higher and total revenues exceeding $1.0 billion. Finally, one company – ALLETE – was eliminated due to the recent spin-off of its non-regulated automotive services division. These criteria resulted in the reference group of 21 electric utilities shown on Document WEA-3, including FPL Group. The average consolidated corporate credit rating for this group of electric utilities is single-A, the same as for FPL.

Q. What other considerations support the use of a proxy group in estimating the cost of equity for FPL?

A. Apart from recognizing the inherent risks and prospects for comparable risk utilities, reference to a proxy group of utilities is essential to insulate against vagaries that can result when the stochastic process involved in estimating the cost of equity is applied to a single company. The cost of equity is inherently unobservable and can only be inferred indirectly by reference to available capital market data. To the extent that the data used to apply the DCF model does not capture the expectations that investors have incorporated into current stock prices, the resulting cost of equity estimates will be biased and fail to reflect investors' required rate of return. Indeed, using even a limited group of companies increases the potential for error, as the FERC noted in its July 3, 2003 *Order on Initial Decision* in Docket No. RP00-107-000:

> Both Staff and Williston agreed that a proxy group of only three companies presented problems because "a single company will have a magnified influence on the group results." It was with those changing market dynamics in mind that witnesses of both Staff and Williston proposed to expand the group of proxy companies to determine a zone of reasonableness.

The 21-company proxy group composed of utilities is consistent not only with shared investment risks, but also with the need to ensure against the potential that a single cost of equity estimate may not reflect investors' required rate of return.

Q. How is the constant growth form of the DCF model typically used to estimate the cost of equity?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (*g*) for the firm. Since book value, dividends, earnings, and price are all assumed to move in lock-step in the constant growth DCF model, estimates of expected growth are sometimes derived from historical rates of growth in these variables under the presumption that investors expect these rates of growth to continue into the future. Alternatively, a firm's internal growth can be estimated based on the product of its earnings retention ratio and earned rate of return on equity. This growth estimate may rely on either historical or projected data, or both. A third approach is to rely on security analysts' projections of growth as proxies for investors' expectations. The final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of equity.

Q. How was the dividend yield for the reference group of electric utilities determined?

A. Estimates of dividends to be paid by each of these electric utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by the corresponding stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock price, and resulting dividend yields for the firms in the electric utility proxy group are presented on Document WEA-3. As shown there, dividend yields for the 21 firms in the electric utility proxy group ranged from 2.5 percent to 5.4 percent, with the average being 4.1 percent.

Q. What are investors most likely to consider in developing their long-term growth expectations?

A. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. Thus, the only "g" that matters in applying the DCF model is that which investors expect and have embodied in current market prices.

Q. Are historical dividend growth rates likely to provide a meaningful guide to investors' growth expectations for electric utilities?

A. No. In response to more accentuated business risks in the industry, electric utilities adopted dividend policies that were much more conservative than in the past. As a result, dividend growth in the electric utility industry has remained largely stagnant in recent years as utilities conserved financial resources to provide a hedge against heightened uncertainties. Responding to this trend, investors' focus increasingly shifted from dividends to earnings as a measure of long-term growth, as payout ratios for firms in the electric utility industry trended downward from approximately 80 percent historically to on the order of 60 percent. [See, *e.g.*, The Value Line Investment Survey (Sep. 15, 1995 at 161, Sep. 5, 2003 at 154)].

Q. What are investors likely expecting in the way of growth for the electric utility proxy group?

A. While historical trends in electric utility dividends provide little guidance as to future expectations, investors have recently expressed renewed interest in dividend payments. As the industry recovers from the financial challenges of the last several years, electric utilities have begun to reevaluate their dividend policies and reinstate increases to their quarterly payout. As a result, projected growth in dividends per share may provide guidance as to investors' expectations.

The dividend growth projections for each of the firms in the electric utility proxy group reported by Value Line are displayed in the first column of Document WEA-4. As shown there, these security analysts' projections suggested average growth the order of 5.6 percent for the reference group of electric utilities.

Q. What other trends do investors consider in developing growth expectations?

A. Trends in earnings, which ultimately support future dividends and share prices, are likely to play a pivotal role in determining investors' long-term growth expectations. Indeed, the importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community. As noted in *Finding Reality in Reported Earnings* published by the Association for Investment Management and Research:

> [E]arnings, presumably, are the basis for the investment benefits that we all seek. "Healthy earnings equal healthy investment benefits" seems a logical equation, but earnings are also a scorecard by which we compare companies, a filter through which we assess management, and a crystal ball in which we try to foretell the future. (p. 1)

Value Line's near-term projections and its Timeliness Rank, which is the principal investment rating assigned to each individual stock, are also based primarily on various quantitative analyses of earnings. As Value Line explained in its *Subscribers Guide*:

> The future earnings rank accounts for 65% in the determination of relative price change in the future; the other two variables (current earnings rank and current price rank) explain 35%. (p. 53)

The fact that investment advisory services, such as Value Line and I/B/E/S International, Inc. (IBES), focus on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, "A Study of Financial Analysts: Practice and Theory," published in the Financial Analysts Journal (July/August 1999), reported the results of a survey conducted to determine what analytical techniques investment analysts actually use. Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities. Of the 297 analysts that responded, only 3 ranked dividends first while 276 ranked it last. The article concluded:

> Earnings and cash flow are considered far more important than book value and dividends. (p. 88)

Q. What are security analysts currently projecting in the way of earnings growth for the firms in the electric utility proxy group?

A. The earnings growth projections for each of the firms in the electric utility proxy group reported by IBES and published in S&P's *Earnings Guide* are also displayed on Document WEA-4. Also presented are the EPS growth projections reported by Zacks Investment Research (Zacks), Value Line, and First Call Corporation (First

Call). As shown there, these security analysts' projections suggested growth the order of 4.9 to 5.3 percent for the reference group of electric utilities:

Electric Utility Proxy Group

Service	Growth Rate
IBES	5.1%
Value Line	5.3%
First Call	5.1%
Zacks	4.9%

Q. **What considerations are relevant in evaluating these near-term growth rates for electric utilities?**

A. Short-term projected growth rates may be colored by lingering uncertainties regarding the near-term direction of the economy in general and the spate of challenges recently faced in the electric power industry specifically. Consider the example of Value Line (Feb. 11, 2005), which has assigned its Utilities sector the lowest ranking of all 10 sectors it covers for year-ahead stock price performance. Value Line noted (December 31, 2004) that "[t]he electric utility industry carries one of our lowest industry Timeliness ranks." While this cautious outlook may be indicative of relatively low near-term growth projections, it does not necessarily reflect investors' long-term expectations for the industry.

Q. **How else are investors' expectations of future long-term growth prospects often estimated for use in the constant growth DCF model?**

A. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Although these conditions are seldom, if ever, met in practice, this approach may provide investors with a rough guide for evaluating a firm's growth prospects. Accordingly, conventional applications of the constant growth DCF model often examine the relationships between retained earnings and earned rates of return as an indication of the sustainable growth investors might expect from the reinvestment of earnings within a firm. The sustainable growth rate is calculated by the formula, $g = br + sv$, where "b" is the expected retention ratio, "r" is the expected earned ROE, "s" is percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.

Q. What is the purpose of the "sv" term?

A. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. When a company's stock price is greater than its book value per share, the per-share contribution in excess of book value associated with new stock issues will accrue to the current shareholders. The higher book value per share leads to higher expected earnings and dividends, with the "sv" factor incorporating this additional growth component.

Q. What growth rate does the earnings retention method suggest for the reference group of electric utilities?

A. The sustainable, "br + sv" growth rates for each firm in the reference group are shown on Document WEA-5. For each firm, the expected retention ratio (b) was calculated based on Value Line's projected dividends and earnings per share. Likewise, each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by projected average net book value. Meanwhile, percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio. As shown there, after incorporating this method resulted in an average expected growth rate for the group of electric utilities of 5.6 percent.

Q. What did you conclude with respect to investors' growth expectations for the reference group of electric utilities?

A. These observable benchmarks suggest that investors currently expect growth on the order of 4.9 to 5.6 percent for the average firm in the electric utility proxy group.

Q. What cost of equity was implied for the reference group of electric utilities using the DCF model?

A. Combining the 4.1 percent average dividend yield with the 5.3 percent midpoint of my representative growth rate range implied a DCF cost of equity for this group of electric utilities of approximately 9.4 percent. As explained earlier, however, no single method or model should be relied upon to determine a utility's cost of equity. In light of anticipated capital market trends, and the recent challenges experienced in the electric utility industry, caution should be exercised in interpreting the results of DCF applications.

Risk Premium Analyses

Q. What other analyses did you conduct to estimate the cost of equity?

A. As I have mentioned previously, because the cost of equity is inherently unobservable, no single method should be considered a solely reliable guide to investors' required rate of return. Accordingly, I also evaluated the cost of equity for

FPL using risk premium methods. My applications of the risk premium method provide alternative approaches to measure equity risk premiums that focused specifically on data for electric utilities and forward-looking estimates of investors' required rates of return.

Q. Briefly describe the risk premium method.

A. The risk premium method of estimating investors' required rate of return extends to common stocks the risk-return tradeoff observed with bonds. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q. How did you implement the risk premium method?

A. The actual measurement of equity risk premiums is complicated by the inherently unobservable nature of the cost of equity. In other words, like the cost of equity itself and the growth component of the DCF model, equity risk premiums cannot be calculated precisely. Therefore, equity risk premiums must be estimated, with adjustments being required to reflect present capital market conditions and the relative risks of the groups being evaluated.

I based my estimates of equity risk premiums for electric utilities on (1) surveys of previously authorized rates of return on common equity, (2) realized rates of return, and (3) alternative applications of the CAPM. Authorized returns presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order, and the returns provide a logical basis for estimating equity risk premiums. Under the realized-rate-of-return approach, equity risk premiums are calculated by measuring the rate of return (including dividends, interest, and capital gains and losses) actually realized on an investment in common stocks and bonds over historical periods. The realized rate of return on bonds is then subtracted from the return earned on common stocks to measure equity risk premiums. The CAPM approach measures the market-expected return for a security as the sum of a risk-free rate and a risk premium based on the portion of a security's risk that cannot be eliminated by holding a well-diversified portfolio. Under the CAPM, risk is represented by the beta coefficient (β), which measures the volatility of a security's price relative to the market as a whole. While controversy surrounds the use of beta to measure a utility's investment risk, the CAPM is routinely referenced in the financial literature and in regulatory proceedings.

While these methods are premised on different assumptions, each having their own strengths and weaknesses, they are widely accepted approaches that have been routinely referenced in estimating the cost of equity for regulated utilities.

Q. How did you implement the risk premium approach using surveys of allowed rates of return?

A. While the purest form of the survey approach would involve querying investors directly, surveys of previously authorized rates of return on common equity are frequently referenced as the basis for estimating equity risk premiums. The rates of return on common equity authorized utilities by regulatory commissions across the

U.S. are compiled by Regulatory Research Associates (RRA) and published in its Regulatory Focus report. In Document WEA-6, the average yield on public utility bonds is subtracted from the average allowed rate of return on common equity for electric utilities to calculate equity risk premiums for each year between 1974 and 2004. Over this 31-year period, these equity risk premiums for electric utilities averaged 3.17 percent, and the yield on public utility bonds averaged 9.59 percent.

Q. Is there any risk premium behavior that needs to be considered when implementing the risk premium method?

A. Yes. There is considerable evidence that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates. In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. To illustrate, the graph shown in Document WEA-7 plots the yields on public utility bonds (solid line) and equity risk premiums (shaded line) shown on Document WEA-6.:

The graph clearly illustrates that the higher the level of interest rates, the lower the equity risk premium, and vice versa. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1 percent increase or decrease in interest rates, the cost of equity may only rise or fall, say, 50 basis points. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have changed since the equity risk premiums were estimated. Finally, it is important to recognize that the historical focus of the risk premium studies almost certainly ensures that they fail to fully capture the significantly greater risks that investors now associate with providing electric utility service. As a result, they are likely to understate the cost of equity for a firm operating in today's electric power industry.

Q. What cost of equity is implied by surveys of allowed rates of return on equity?

A. As illustrated above, the inverse relationship between interest rates and equity risk premiums is evident. Based on the regression output between the interest rates and equity risk premiums displayed at the bottom of page 1 of Document WEA-6, the equity risk premium for electric utilities increased approximately 43 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated there, with the yield on average public utility bonds in January 2005 being 5.80 percent, this implied a current equity risk premium of 4.80 percent for electric utilities. Adding this equity risk premium to the January 2005 yield on single-A public utility bonds of 5.78 percent produces a current cost of equity for the utilities in the benchmark group of approximately 10.6 percent.

Q. What else should be considered in applying risk premium methods?

A. As noted earlier, there is widespread consensus that interest rates will increase materially as the economy continues to strengthen, with the Federal Reserve's recent actions indicative of tighter credit conditions in the months ahead. As a result, current bond yields are likely to understate capital market requirements at the time the outcome of this proceeding becomes effective. Accordingly, I also applied the alternative risk premium methods based on a forecasted bond yield for the 2006 test year developed based on an average of the projections published by EIA, GlobalInsight, and Blue Chip. This is analogous to the approach adopted by the FPSC staff in applying the CAPM in its May 20, 2004 *Memorandum* in Docket No.

040006-WS, as well as the methodology employed by FPSC staff witness Andrew L. Maurey in Docket No. 000824-EI.

Q. What cost of equity was produced by the authorized rate of return approach after incorporating the 2006 bond yield forecast?

A. As shown on page 2 of Document WEA-6, after incorporating a forecasted yield for 2006 and adjusting for changes in interest rates since the study period, this implied a current equity risk premium of 4.29 percent for electric utilities. Adding this equity risk premium to the implied yield on single-A public utility bonds for the 2006 test year of 7.0 percent resulted in an implied cost of equity of approximately 11.3 percent.

Q. How did you apply the realized-rate-of-return approach?

A. Widely used in academia, the realized-rate-of-return approach is based on the assumption that, given a sufficiently large number of observations over long historical periods, average realized market rates of return will converge to investors' required rates of return. From a more practical perspective, investors may base their expectations for the future on, or may have come to expect that they will earn, rates of return corresponding to those realized in the past. Indeed, average realized rates of return for historical periods are widely reported to investors in the financial press and by investment advisory services as a guide to future performance. By focusing on data for utilities specifically, my realized rate of return approach avoided the need to make assumptions regarding relative risk (*e.g.*, beta) that are often embodied in applications of this method.

Stock price and dividend data for the electric utilities included in the S&P 500 Composite Index (S&P 500) are available since 1946. Document WEA-8 presents annual realized rates of return for these utilities in each year between 1946 and 2003. As shown there, over this 58-year period realized rates of return for these utilities have exceeded those on single-A public utility bonds by an average of 3.87 percent. In contrast to other risk premium approaches, the realized-rate-of-return method assumes that equity risk premiums are stationary over time; therefore, no adjustment for the inverse relationship between equity risk premiums and interest rates was made. Adding the 3.87-percent equity risk premium to the January yield of 5.78 percent on single-A public utility bonds produces a current cost of equity of approximately 9.7 percent.

Once again, however, this does not consider the anticipated increase in bond yields through the test year. Adding this 3.87 percent equity risk premium to the 7.0 percent forecasted yield on single-A public utility bonds for 2006 implies cost of equity of approximately 10.9 percent.

Q. **Please describe your application of the CAPM.**

A. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Under the CAPM, investors are assumed to be fully diversified, so the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole. Beta reflects the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

Where: Rj = required rate of return for stock j;

Rf = risk-free rate;

Rm = expected return on the market portfolio; and,

βj = beta, or systematic risk, for stock j.

I applied the CAPM to the 21 companies in the electric utility proxy group using market risk premiums (R_m - R_f) based on (1) forward-looking estimates of investors' required rates of return and (2) historical realized rates of return.

Q. Please describe your forward-looking application of the CAPM.

A. Application of the CAPM to the utilities in the proxy group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Document WEA-9. Rather than using historical data, the expected market rate of return was estimated by conducting a DCF analysis on the firms in the S&P 500. The dividend yield was obtained from S&P, with the growth rate equal to the average of the composite earnings growth projections published by IBES for each firm. Based on the average of the individual IBES growth rates for the firms in the S&P 500, as reported in S&P's Earnings Guide (Feb. 2005), current estimates imply an average projected growth rate for the firms in the S&P 500 over the next five years of 12.1 percent. Combining this average growth rate with a contemporaneous yield of 1.8 percent results in a current cost of equity estimate for the market as a whole of approximately 13.9 percent. Subtracting a 4.6 percent risk-free rate based on the February 2005 average yield on 20-year Treasury bonds from the 13.9 percent forward-looking rate of return produced a market equity risk premium of 9.3 percent. Multiplying this risk premium by the average Value Line beta of 0.77 for the electric utilities in the proxy group, and then adding the resulting 7.2 percent risk premium to the February 2005 average long-term Treasury bond yield, resulted in a current cost of equity of approximately 11.8 percent.

Q. **What cost of equity is implied by this forward-looking application of the CAPM after incorporating 2006 projected government bond yields?**

A. As shown on page 2 of Document WEA-9, interest rate projections published by EIA, GlobalInsight and Blue Chip imply a projected yield on 20-year Treasury bonds of 5.8 percent for the 2006 test year, which results in a market risk premium of 8.1 percent. Once again multiplying the market risk premium by the average Value Line beta of 0.77 for the electric utilities in the proxy group, and then adding the resulting 6.2 percent risk premium to the 5.8 percent long-term Treasury bond yield for 2006, implied a cost of equity of approximately 12.0 percent.

Q. **What other CAPM analyses did you conduct to estimate the cost of equity?**

A. I also applied the CAPM using risk premiums based on historical realized rates of return. This approach to estimating investors' equity risk premiums is premised on the assumption that, given a sufficiently large number of observations over long, historical periods, average realized market rates of return will converge to investors' required rates of return.

Q. **What CAPM cost of equity is produced based on historical realized rates of return for stocks and long-term government bonds?**

A. I applied the CAPM using data published by Ibbotson Associates, which is perhaps the most exhaustive and widely referenced annual study of realized rates of return. Application of the CAPM based on historical realized rates of return is presented in Document WEA-10. In their *2004 Yearbook, Valuation Edition*, Ibbotson Associates reported that, over the period 1926 through 2003, the arithmetic mean realized rate of return on the S&P 500 exceeded that on long-term government bonds by 7.2 percent. Multiplying this historical market risk premium by the average Value Line beta of 0.77 produced an equity risk premium of 5.5 percent for the electric utility proxy group. As shown on page 1 of Document WEA-10, adding this equity risk premium to the February 2005 average yield on 20-year Treasury bonds of 4.6 percent resulted in an implied cost of equity of 10.1 percent. As shown on page 2 of Document WEA-10, after incorporating a projected government bond yield for 2006, application of the CAPM based on historical realized rates of return implied a cost of equity of 11.3 percent for the test year.

Q. What else should be considered in applying the CAPM using historical realized rates of return?

A. The CAPM model, like the DCF approach, is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, in order to accurately estimate required returns the CAPM must be applied using data that reflects the expectations of actual investors. While reference to historical data represents one way to apply the CAPM, these realized rates of return reflect, at best, an indirect estimate of investors' current requirements. As a result, applications of the CAPM that look directly at investors' expectations in the capital markets are apt to provide a more meaningful guide to investors' required rate of return. Accordingly, because the historical approach does not incorporate forward-looking estimates, it was given less weight in arriving at my recommended return on equity.

Proxy Group Cost of Equity

Q. What did you conclude with respect to the cost of equity for the proxy group of utilities?

A. The cost of equity estimates implied by my quantitative analyses are summarized in WEA-11. In light of anticipated capital market trends, and the recent challenges experienced in the electric utility industry, caution should be exercised in interpreting the results of DCF and risk premium applications. Considering FPL's 2006 test year, accelerating economic growth and expectations for higher interest rates suggest that test year estimates should receive more weight. Accordingly, based on the results of my quantitative analyses, and my assessment of the relative strengths and weaknesses inherent in each method, I concluded that the cost of equity for the proxy group is in the range of 10.0 to 12.0 percent.

Q. What other considerations are relevant in setting the return on equity for a utility?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Q. Is there an established mechanism for a utility to recognize equity issuance costs?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. Alternatively, no rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most logical mechanism.

Q. What is the magnitude of the adjustment to the "bare bones" cost of equity to account for issuance costs?

A. There are any number of ways in which a flotation cost adjustment can be calculated, and the adjustment can range from just a few basis points to more than a full percent. One of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, Roger A. Morin concluded in *Regulatory Finance: Utilities' Cost of Capital* (1994):

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue. (p. 166)

Applying these expense percentages to a representative dividend yield for a utility of 4.1 percent implies a flotation cost adjustment on the order of 20 to 40 basis points. Similarly, staff witness Mr. Maurey utilized a 26 basis point adjustment in Docket No. 000824-EI, with the FPSC incorporating a 4 percent flotation cost adjustment in its June 10, 2004 Order No. PSC-04-0587-PAA-WS.

Q. What then is your conclusion regarding a fair rate of return on equity for the companies in your proxy group?

A. After incorporating an adjustment for flotation costs of 30 basis points to my "bare bones" cost of equity range, I concluded that a fair rate of return on equity for the proxy group of utilities is currently in the range of 10.3 to 12.3 percent.

RETURN ON EQUITY FOR FPL

Q. What is the purpose of this section?

A. This section addresses the economic requirements for FPL's rate of return on equity. It examines other factors properly considered in determining a fair rate of return, including FPL's relative risk exposure and an ROE reward for exemplary results. This section also discusses the regulatory policy reasons for avoiding a return on equity that is not sufficient to maintain FPL's financial integrity and ability to attract capital. Finally, this section presents my conclusions regarding the fair rate of return and evaluates the reasonableness of FPL's capital structure.

Relative Risks

Q. How can the overall investment risks of FPL be compared with the electric utility proxy group?

A. Perhaps the most objective guide to a utility's overall investment risk is its bond rating. Bond ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. The ratings assigned to a utility by the rating agencies are typically based on an evaluation of the utility's business and financial risks. The evaluation of business risk tends to be fairly qualitative, and involves an examination of the utility's relative markets and service area economy, competitive position, operations, regulation, management, supply position, and asset concentration. Meanwhile, the evaluation of financial risk tends to be more quantitative and involves an examination of financial data concerning earnings protection, capital structure, cash flow adequacy, and financial flexibility. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, bond ratings provide the most all-encompassing measure of investment risk readily available to investors. Ratings generally extend from triple-A (the highest) to D (in default). Other numerical designations (*e.g.*, "A1") or symbols (*e.g.*, "A+") are used to show relative standing within a category. Within the investment grade categories (triple-A through triple-B), the distinctions between these refined ratings designations tend to reflect a very modest gradation in risk.

Bond ratings are widely cited in the investment community and referenced by investors as an objective measure of risk. While the bond rating agencies are primarily focused on the risk of default associated with the firm's debt securities, bond ratings and the risks of common stock are closely related. As noted in *Regulatory Finance: Utilities' Cost of Capital*:

> Concrete evidence supporting the relationship between bond ratings and the quality of a security is abundant. ... The strong association between bond ratings and equity risk premiums is well documented in a study by Brigham and Shome (1982). (p. 81)

Indeed, bond ratings are frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of equity

Q. What does a comparison of bond ratings indicate with respect to FPL's relative investment risks?

A. The average consolidated corporate debt rating for the utility proxy group is "A-", with ratings for the individual firms ranging from "BBB+" to "A". Considering that the "+" and "-" designations tend to reflect very modest gradations in risk, this average single-A rating for the proxy group is essentially identical to FPL's corporate credit rating. On the other hand, S&P has assigned a "negative" outlook to FPL's senior debt, informing investors of the potential for reduced credit standing and further downgrades going forward. Given that FPL's corporate credit rating is essentially identical to that of the reference group, and considering FPL's "negative" outlook, investors would likely conclude that the overall investment risks for FPL are comparable to those of the firms in the electric utility proxy group.

Q. What other factors would investors likely consider in evaluating the relative investment risks of FPL?

A. Approximately 21 percent of FPL's total energy requirements are provided by its four nuclear units located at the St. Lucie and Turkey Point generating stations.

FPL's nuclear facilities represent a significant portion of its generating capability, and this concentration exposes FPL to substantial additional costs for repairs and replacement power in the event of a disruption.

Longer-term uncertainties regarding the disposal of spent fuel and the ultimate costs of decommissioning continue to accompany any investment in nuclear generating facilities, even for a firm with an exemplary history of operational success like FPL. As of year-end 2004, for example, FPL had paid $520 million to the DOE for transportation and disposal of spent fuel; but the DOE has failed to meet its statutory obligations. As a result, FPL has been forced to store spent fuel on site and, absent expanded capabilities, it will lose its ability to accommodate additional spent fuel storage at St. Lucie Unit Nos. 1 and 2 by 2008 and 2007, respectively. In addition, security risks have been heightened since the September 11th terrorist attacks, mandating increased security measures and oversight. The exposure to potential new threats and additional security-related costs are undoubtedly considered in investors' assessment of the uncertainties surrounding FPL's nuclear plants.

FPL's relatively greater reliance on nuclear power relative to the majority of the other firms in the electric utility proxy group used to estimate the cost of equity implies that it faces additional risks. While a precise quantification of the impact of these uncertainties on the cost of equity is problematic, investors undoubtedly consider them in establishing their required rate of return. Given the benefits that consumers have realized as a result of FPL's investment in nuclear facilities, fairness dictates that the corresponding risks be considered in establishing FPL's allowed rate of return on equity.

Q. What other operational factors are of concern to investors?

A. In order to meet rising demand for electricity across its service territory, FPL has sought to acquire additional power resources to ensure its ability to maintain adequate reserve margins and provide reliable service. In addition to the planned addition of new natural gas-fired facilities at its Martin and Manatee plants (in June 2005) and the additional combined-cycle unit planned for Turkey Point plant (June 2007), FPL also added approximately 2,700 MW of new generation between 2001 and 2003, primarily through repowering existing oil-fired units, thereby converting smaller, less efficient oil-fired generators to larger, very efficient natural gas units. This expansion of gas-fired generation has increased concerns over fuel diversity and exposure to fluctuations in natural gas prices or supply interruption. S&P noted investors' concerns in a July 1, 2004 *RatingsDirect* report:

> By 2009, about half of the energy consumed by the utility will be produced from natural gas, raising concerns about fuel concentration, especially considering Florida's limited supply of gas and dependence on the Gulf of Mexico through two interstate pipelines for its supply.

While FPL continues to explore alternative fuel sources and generation technologies, such as liquefied natural gas (LNG), renewable technologies and advanced coal generation, the potential exposure remains of concern to investors.

Q. How does the nature of the economy in FPL's service territory impact its relative risks?

A. Past experience indicates that the economy in FPL's service territory can be highly vulnerable to any conditions that cause a decline in tourism. In the early 1970s, for example, the Florida economy was experiencing strong growth with the opening of major tourist attractions, a vibrant real estate market, and a residential construction boom. Then came the Arab oil embargo that choked the flow of tourists, who at that time mostly arrived by car, and higher interest and inflation rates that contributed to a collapse of the construction industry. Just as the skyrocketing gas prices of the 1970s dampened consumers' willingness to travel, the 2001 terrorist attacks had a significant and sustained impact on Florida's tourism industry and the state's economy. FPL was one of five utilities singled out by S&P as being particularly vulnerable to a decline in tourism (*RatingsDirect*, October 5, 2001), a viewpoint that was confirmed in the aftermath of the September 11th terrorist attacks. As a contemporaneous commentary on Florida's economy (Florida Trend, "Where We Stand," November 1, 2001) noted:

> Tourism, the linchpin of Florida's economy, unquestionably took the heaviest blow in the fallout from the terrorist attacks. Slightly more than half of all visitors to Florida come by plane (one in 10 comes from New York); the interruption and subsequent reduction in airline service and the public's reluctance to travel turned what had been a soft slide in tourism into a free-fall, with central Florida and south Florida suffering the most. (p. 7)

And while the Florida economy has achieved a degree of diversification that was not present during the tourism-led decline in the 1970s, Floridians are aware that the combined effect of a general business slowdown and a plunge in tourism can result in a particularly severe economic double-whammy, which heightens the risks of an economic downturn for FPL's investors and customers. Investors are undoubtedly positive on the future outlook for Florida's economy, but they nonetheless recognize the additional volatility introduced by the state's dependence on the tourism industry.

Q. What is your conclusion regarding the relative investment risks of FPL, as compared with the average firm in the electric utility proxy group?

A. FPL's corporate credit rating, which provides the most objective and encompassing measure of overall investment risk, is identical to that maintained by the average firm in the electric utility proxy group. Moreover, investors view FPL's relatively high reliance on nuclear generation, evolving exposure to natural gas markets, and the dependence of its service area economy on tourism as significant risks. Based on my evaluation, and considering the mitigating benefits of FPL's relatively conservative capital structure discussed subsequently, I concluded that investors would be unlikely to distinguish between the investment risks of FPL and those of the benchmark group of electric utilities.

Capital Structure

Q. Is an evaluation of the capital structure maintained by a utility relevant in assessing its return on equity?

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt, and preferred stock, means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders and preferred stockholders are exposed, and they require correspondingly higher rates of interest and dividends, respectively, for their risk bearing. From common shareholders' standpoint, higher debt and preferred stock ratios mean that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain.

Q. What capital structure is reflected in FPL's MFR filings?

A. The capital structure reflected in FPL's MFR filings (excluding deposits, deferrals, and cost-free sources) for test year ended December 31, 2006 is as follows ($000):

13-Month Average Jurisdictional Balance

Component	Amount	%
Short-term Debt	$ 61,631	0.61%
Long-term Debt	3,751,548	37.47%
Common Equity	6,200,049	61.92%
Total	$10,013,049	100.00%

Q. Do the ratios shown above provide a representative basis on which to evaluate FPL's capital structure?

A. No. As discussed earlier, a significant portion of FPL's power requirements are obtained through long-term purchased power contracts. Because these agreements obligate FPL to make certain capacity and minimum contractual payments akin to those associated with traditional debt financing, investors consider these commitments in evaluating FPL's financial risks. The implications of purchased power commitments for a utility's financial risks have been repeatedly cited by major bond rating agencies. As early as 1990, Moody's recognized the financial risk imposed by the off-balance-sheet liabilities associated with purchased power and the resulting erosion of the utility's financial flexibility (*Electric Utility Week*, October 8, 1990). Similarly, S&P observed in a 1992 ratings report for FPL that "a utility incurs certain risks when entering into a long-term contract with fixed-cost capacity component" (*CreditWeek*, April 6, 1992). As S&P observed in "Buy Versus Build Debate Revisited" (*CreditWeek*, May 24, 1993):

> When a utility enters into a long-term purchased power contract with a fixed-cost component, it takes on financial risk. Heavy fixed charges reduce a utility's financial flexibility and long-term contractual arrangements represent – at least in part – off balance sheet debt equivalents. (pp. 1-2)

More recently, in reviewing its evaluation of the credit implications of purchased power, S&P reaffirmed its position that such agreements are "debt-like in nature" and that the increased financial risk must be considered in evaluating a utility's credit risks ("'Buy Versus Build': Debt Aspects of Purchased-Power Agreements", *Utilities & Perspectives*, May 12, 2003).

Because the capacity and minimum contractual payment obligations under power purchase agreements are analogous to those associated with traditional debt financing, investors consider these commitments in evaluating FPL's financial risks. Accordingly, incorporating the debt equivalent of FPL's obligations under its purchased power contracts in the Company's capital structure would have the effect of increasing its financial leverage.

Q. What implications do relatively greater amounts of purchased power have for a utility's financial flexibility?

A. Because investors perceive additional financial risks with obligations under purchased power contracts, as reliance on these sources increases, the utility must offset the associated debt equivalent by incorporating a higher equity component in the capital structure to neutralize the effect on leverage. As S&P has recognized, because of purchased power, it has been necessary for FPL to maintain a relatively greater proportion of equity capital in order to maintain its credit standing. In a December 3, 1998 report in *RatingsDirect*, S&P noted that:

> Florida Power & Light has a sizeable amount of fixed payment purchased-power contracts, a portion of which is imputed by Standard & Poor's as an off-balance-sheet obligation, and has maintained a higher amount of equity capital on the balance sheet to counter this off-balance-sheet debt obligation. (p. 2)

More recently, S&P noted that it "includes about $1.3 billion as a debt equivalent" because of FPL's purchased power obligations (*Research: FPL Group, Inc.*, Oct. 21, 2003). Absent financial policies that recognize the leverage implicit in purchased power contracts, the associated investment risks would place downward pressure on utilities' creditworthiness and debt ratings and the greater leverage implied by a lower common equity ratio would increase investors' required rate of return for both debt and equity securities.

Apart from the immediate impact the debt-equivalent portion of purchased power costs has on the utility's financial risk, heavy fixed charges also reduce ongoing financial flexibility, and the utility may face other uncertainties, such as potential replacement power costs in the event of supply disruption. Moreover, investors' focus on the financial ramifications and other uncertainties of purchased power is magnified as the utility's reliance on purchased power increases.

Q. Is the full amount of FPL's purchased power obligations typically treated as debt in evaluating its financial leverage?

A. No. The present value of the fixed obligations associated with FPL's purchased power contracts amounts to approximately $3.83 billion, which is roughly 1.4 times the $2.8 billion in long-term debt reflected on its balance sheet at December 31, 2004. While arguments could be made to consider the full amount as debt equivalents, the major bond rating agencies typically include only a portion of this present value as debt in analyzing relative financial risks. While other rating agencies have expressed similar concerns regarding the financial impacts of purchased power commitments, S&P is largely unique in having a defined quantitative analysis to account for the additional risks associated with these contractual commitments. This methodology begins by quantifying the potential off-balance sheet obligation attributable to long-term power purchase contracts. The first step in this process involves calculating the net present value of the remaining capacity payments over the life of the agreement, determined using a discount rate of 10 percent.

Next, S&P evaluates the characteristics of a utility's purchased power contracts, placing each agreement on a risk spectrum according to the degree to which payments under the contract resemble the fixed obligations of traditional debt instruments, such as long-term bonds. Within the S&P analytical framework, this difference in the relative debt characteristics of purchase power obligations is accommodated using a risk spectrum ranging from 0 to 100 percent. This risk factor represents the proportion of the obligations' net present value to be considered off-balance sheet debt. For example, if S&P determines that the risk factor for a specific purchased power contract is 50 percent, S&P considers 50 percent of the net present value of the related capacity payments as a debt equivalent and adds this to reported obligations.

In determining the risk factor S&P considers a variety of qualitative factors related to the purchased power contract. Previously, contracts that were relatively more firm in terms of their delivery and payment obligations were generally considered more debt-like than others. However, in a May 12, 2003 report ("'Buy Versus Build': Debt Aspects of Purchased-Power Agreements," *Utilities & Perspectives*), S&P explained that it had revised its approach to recognize significant structural changes in the electric power industry. Rather than evaluating the likelihood of payment under purchased power contracts, S&P has revised its assessment to place particular emphasis on the method under which the utility recovers of purchased power costs. For example, assuming adequate regulatory treatment, S&P now assigns a 50 percent risk factor where payments under long-term purchased power commitments are included in a utility's base rates. S&P concluded (*Utilities & Perspectives*, May 12, 2003) that a risk factor as low as 30 percent could be justified for utilities with supportive regulation that recover purchased power costs via a fuel adjustment clause (FAC), as opposed to base rates:

> For utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased power costs, a risk factor of as low as 30% could be used.

By evaluating the characteristics of a utility's purchased power contracts, S&P places each agreement on a risk spectrum according to the degree to which payments under the contract resemble the fixed obligations of traditional debt instruments, such as long-term bonds. Obligations on the lower end of the scale would have fewer debt-like characteristics and would be considered less firm than the obligations placed at the high end of the scale. Based on this ranking, a risk factor is assigned that indicates the portion of the present value of fixed payments that are considered as debt-equivalents. For example, obligations under take-or-pay contracts that are unconditional as to both acceptance and availability of power are considered relatively firm (risk factors between 40 percent and 80 percent), while agreements that require capacity payments only if power is available are considered less debt-like (risk factors between 10 percent and 50 percent). *S&P* assigns each of FPL's purchased power commitments a risk factor in the 10 to 50 percent range.

Q. What capital structure is implied for FPL's 2006 test year once the off balance sheet obligations associated with purchased power contracts are incorporated?

A. As S&P has recognized, because of purchased power, it has been necessary for FPL to maintain a relatively greater proportion of equity capital in order to maintain its credit standing. Based on S&P's methodology described above, a $1.1 billion upward adjustment to long-term debt was incorporated for 2006 to account for the debt equivalent attributed to FPL's off balance-sheet obligations. This results in the adjusted capital structure ratios shown in the following table ($000):

Adjusted 13-Month Average Jurisdictional Balance

Component	Amount	%
Short-term Debt	$ 61,631	0.55%
Long-term Debt	4,843,682	43.62%
Common Equity	6,200,049	55.83%
Total	$11,105,362	100.00%

These calculations not only reflect the investment community's evaluation of FPL's financial risks, they are also consistent with 55.83 percent adjusted equity ratio that forms the surveillance cap specified under the terms of the Revenue Sharing Agreement approved in Docket No. 001148-EI. Moreover, as discussed in Mr. Dewhurst's testimony, past decisions of the FPSC have acknowledged that an adjustment is appropriate to address the capital structure impact associated with purchased power.

Q. Have similar adjustments for the financial impact of purchased power been recognized by other state regulators?

A. Yes. For example, the staff of the Public Service Commission of Wisconsin (PSCW) recommended, and the Commission concurred, that an adjustment to reflect the debt leverage implicit in purchased power obligations was appropriate for Madison Gas and Electric Company in Docket No. 3270-UR-112. Similarly, in a settlement agreement involving Public Service Company of Colorado (Docket No. 04-A-214E), the staff of the Colorado Public Utilities Commission also recognized that a higher equity ratio was required "to offset the debt equivalent of existing purchased power agreements and to improve the Company's overall financial strength."

Q. How can FPL's adjusted capital structure be evaluated?

A. It is generally accepted that the norms established by comparable firms provide one valid benchmark against which to evaluate the reasonableness of a utility's capital structure. The capital structure maintained by other electric utilities should reflect their collective efforts to finance themselves so as to minimize capital costs while preserving their financial integrity and ability to attract capital. Moreover, these industry capital structures should also incorporate the requirements of investors, both debt and equity, as well as the influence of regulators.

Q. What capitalization ratios are maintained by other electric utilities?

A. Document WEA-12 displays capital structure data at year-end 2003 for the group of electric utility operating companies owned by the firms in the proxy group (excluding FPL) used to estimate the cost of equity. As shown there, the permanent, long-term capitalization for this group of other electric utility operating companies was composed of 45.3 percent long-term debt, 2.5 percent preferred, and 52.1 percent common equity. While S&P does not routinely publish data quantifying any off-balance sheet liabilities that might be attributable to these operating companies, in contrast to FPL, such amounts would be unlikely to have a significant impact on the capitalization of most utilities.

The individual common equity ratios for the group of electric utility operating companies ranged from a low of 36.3 percent (PECO Energy) to a high of 77.6 percent (Union Light, Heat, and Power Co.). Incorporating the same short-term debt ratio reflected in FPL's adjusted 2006 capitalization of approximately 0.55 percent results in the average capital structure ratios for this group of other utilities summarized below:

Electric Utility Operating Companies

Capital Component	**% of Total**
Short-term Debt	0.6%
Long-term Debt	45.1%
Preferred Securities	2.5%
Common Equity	51.8%
Total	100.0%

Q. What implication does the increasing risk of the electric power industry have for the capital structures maintained by utilities?

A. In response to heightened uncertainties in the industry, bond rating agencies have recognized that utilities must adopt a more conservative financial posture if credit ratings are to be maintained. Similarly, the FPSC has also recognized that a more conservative financial policy is consistent with increasing risk in the electric utility industry, observing that "equity ratios in the electric utility industry are increasing, reflecting the increased business risk." [97FPSC 4:320-321] Accordingly, higher levels of business risk imply that utilities will be required to incorporate relatively greater amounts of equity in their capital structures. More recently, Value Line reported in its December 3, 2004 edition (p. 154) that the average common equity ratio for all firms in the electric utility industry is expected to increase significantly over the next three to five years. Indeed, the fact that there has been little moderation in the risks of the electric utility industry since the FPSC approved the Revenue Sharing Agreement in Docket No. 001148-EI supports the continued reasonableness of the 55.83 equity ratio benchmark specified in the stipulation.

Q. How does FPL's capital structure compare with other widely cited financial benchmarks for electric utilities?

A. The financial ratio guidelines published by S&P specify a range for a utility's total debt ratio that corresponds to each specific bond rating. Widely cited in the investment community, these ratios are viewed in conjunction with a utility's *business profile* ranking, which ranges from 1 (strong) to 10 (weak) depending on a utility's relative business risks. Thus, S&P's guideline financial ratios for a given rating category (e.g., triple-B) vary with the business or operating risk of the utility. In other words, a firm with a *business profile* of "2" (*i.e.*, relatively lower business risk) could presumably employ more financial leverage than a utility with a business profile assessment of "9" while maintaining the same credit rating. S&P has assigned FPL a *business profile* ranking of "4".

S&P recently published revised financial guideline ratios, with its capital structure benchmarks being presented in the form of total debt ratios, with the remainder of capital structure being composed of equity. ["New Business Profile Scores Assigned for U.S. Utility and Power Companies: Financial Guidelines Revised," *RatingsDirect* (Jun. 2, 2004)]. Consistent with S&P's current ratings criteria and FPL's S&P *business profile* ranking of "4", a ratio of total debt to total capital in the range of 45 to 52 percent is specified for a single-A bond rating. FPL's 2006 adjusted capital structure shown earlier implies a total debt ratio of approximately 44.2 percent, composed of short-term and long-term debt.

Q. What did you conclude regarding the reasonableness of FPL's capital structure?

A. Based on my evaluation, I concluded that the approximately 55.8 percent common equity ratio maintained by FPL continues to represent a reasonable mix of capital sources from which to calculate FPL's overall rate of return. Although FPL's adjusted common equity ratio falls above the average currently maintained by the proxy group of electric utility operating companies, it is well within the range of individual results for this reference group and consistent with the trend towards lower financial leverage expected for the industry. It is also consistent with the relatively greater uncertainties associated with FPL's exposure to nuclear generation and the South Florida economy. Moreover, while the total debt ratio of 44.2 percent implied by FPL's adjusted capital structure falls slightly below the guidelines that S&P specifies for a single-A bond rating, this relatively conservative financial posture did not forestall S&P from maintaining a "negative" outlook, indicating the potential for further declines in credit ratings.

Q. If FPL's debt ratio exceeds the guidelines for a single-A rating, why wouldn't the utility qualify for an upgrade?

A. As noted earlier, the bond rating agencies consider a plethora of factors relevant to their assessment of a company's overall credit standing. S&P, and investors generally, clearly recognize that the benefits of a strong financial position are offset by a variety of other considerations affecting FPL's relative risk. First, apart from the immediate impact that the debt-equivalent portion of purchased power costs has on FPL's financial risks, other uncertainties are associated with these sources, such as potential replacement power costs in the event of supply disruption. The heavy fixed charges associated with these obligations also reduce FPL's ongoing financial flexibility. Second, investors are undoubtedly sensitive to FPL's relatively greater reliance on nuclear power, which entails significant uncertainties not associated with other forms of generation. FPL's southern location on the Florida peninsula, which dictates that any power flows from outside the region must come from the north, also contributes to FPL's risks, as does increasing concerns over limited gas supplies and potential price volatility. Finally, as the events of 2001 made abundantly clear, the exposure of FPL's service area economy to tourism-led volatility heightens the risks perceived by investors, especially in the midst of an economic downturn. While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces. In this regard, FPL has chosen to maintain a relatively high equity ratio due to the unique challenges posed by its heavy reliance on purchased power and nuclear generation, the burden of its significant capital spending requirements, and the circumstances of its service area economy. Absent these financial policies, FPL's debt ratings would undoubtedly be lower than present levels and the greater investment risks implied by a lower common equity ratio would increase investors' required rate of return for FPL's debt and equity securities. A lower equity ratio for FPL would also imply that its investment risks exceed those of the proxy group used to estimate the cost of equity, implying a cost of equity above that reflected in my recommendations.

Q. **What other indications confirm the reasonableness of FPL's capital structure policies?**

A. In response to the challenges experienced in the utility industry, debt levels have come under increased scrutiny by bond rating agencies and investors. For those firms with higher leverage, this focus can lead not only to ratings downgrades, but to reduced access to capital and increased borrowing costs. While financial flexibility plays a crucial role in ensuring the wherewithal to meet the needs of customers, utilities with higher leverage may be foreclosed from additional borrowing, especially during times of stress.

FPL's capital structure is just one reflection of FPL's ongoing efforts to maintain access to capital on reasonable terms in order to ensure its ability to meet the demands of its obligations to customers. The reasonableness of FPL's requested capital structure is reinforced by the ongoing uncertainties associated with the electric power industry, FPL's unique risks and geographic position, the need to support continued system expansion, and the imperative of maintaining continuous access to capital, even during times of adverse industry and market conditions.

Implications for Financial Integrity

Q. **Why is it important to allow FPL an adequate rate of return on equity?**

A. Given the social and economic importance of the electric utility industry, it is essential to maintain reliable and economical service to all consumers. While a utility may be committed to deliver reliable electric service at the lowest possible price, its ability to fulfill this mandate can be compromised if it lacks the necessary financial wherewithal.

Q. **What lessons can be learned from recent events in the energy industry?**

A. While Florida clearly does not face a California-style power crisis, events in the western U.S. provide a dramatic illustration of the high costs that all stakeholders must bear when a utility's financial integrity is compromised. California's failed market structure led to unprecedented volatility in wholesale power costs throughout the entire western region. For many utilities, recovery of purchased energy costs that they were forced to buy to serve their customers was either prevented and/or postponed. As a result, they were denied the opportunity to earn risk-equivalent rates of return and access to capital was cut off. Regional economies have been jolted and consumers have suffered the results of higher cost power and reduced reliability. Moreover, while the impact of the utilities' deteriorating financial condition was felt swiftly, stakeholders have discovered first hand how difficult and complex it can be to remedy the situation after the fact.

For an electric utility with an obligation to provide reliable service, investors' increased reticence to supply additional capital highlights the necessity of preserving flexibility, even during periods of adverse capital market conditions. *Moody's* affirmed this concern in a January 2001 *Special Comment*:

> [C]areful attention to ensure adequate liquidity, central to any good credit story, is heightened because unexpected increases in demand for capital can occur at any time when so much change is happening. (p. 6)

As the plight of utilities such as PG&E and Sierra Resources makes clear, the consequences of inadequate financial resources can be sudden and severe.

Q. Do you have any personal experience regarding the damage to customers that can result when a utility's financial integrity deteriorates?

A. Yes. I was a staff member of the Public Utility Commission of Texas (PUCT) when the financial condition of El Paso Electric Company (EPE) began to suffer in the late 1970s. I later observed first-hand the difficulties in reversing this slide as a consultant to Asarco Mining, EPE's largest single customer, and later as a consultant to the utility during its struggle recover its financial health. EPE's ultimate bankruptcy imposed enormous costs on customers and absorbed an undue amount of the PUCT's resources, as well as those of the Attorneys General and other state agencies. Some twenty-five years later, EPE has only recently managed to recover an investment grade bond rating and has yet to pay common dividends. There is no question that customers and other stakeholders would have been far better off had EPE avoided bankruptcy by maintaining its financial resilience.

Q. Do the exposures peculiar to FPL highlight the need for ongoing support of the company's financial strength and ability to attract capital?

A. Most definitely. As discussed earlier, FPL faces a number of potential challenges that might require the relatively swift commitment of considerable capital resources in order to maintain the high level of service to which its customers have become accustomed. For example, while FPL's nuclear program is universally regarded as exemplary, mandated shutdowns in response to security threats or a catastrophic event elsewhere in the U.S. would impose significant reliance on wholesale power markets to meet energy shortfalls. FPL's reliance on purchased power for a significant portion of its power requirements also imposes increased vulnerability to supply disruptions, especially in light of its relative geographic isolation on the Florida peninsula. Similarly, any interruption of gas supplies due to deliverability constraints imposed on FPL's suppliers could also result in the need for a considerable financial commitment for an alternative fuel source or replacement power. Given the potential for significant volatility in wholesale energy markets and FPL's lack of control over the timing of such events, FPL must have the wherewithal to meet these challenges even when capital and energy market conditions are unfavorable.

Apart from this exposure to the vagaries of capital and energy market conditions, FPL must simultaneously meet the needs of a fast-growing service area.

Indeed, customer accounts grew by more that 2.6 percent during 2004, with Moody's recognizing in an October 2004 analysis that:

> One of the most important factors driving FP&L's business strategy is the rising demand for electricity across the company's service territory, fueled in large part by the high rate of growth in FP&L's residential customer base. In 2003, FP&L's customer accounts grew by more than 2.4% and electricity sales (excluding interchange sales) hit an all-time high of 100.85 billion kWh, representing a healthy 4.2% increase over 2002 levels.

Similarly, Fitch noted (Sep. 23, 2004) that "significant ongoing capital expenditure requirements for new generating resources to meet customer and usage growth" were a significant credit concern for FPL. Providing the infrastructure necessary to support a buoyant and growing economy is certainly necessary and desirable, but it also imposes considerable responsibilities on FPL. To continue to meet these challenges successfully and economically, it is crucial that FPL receive adequate support for its credit standing. The pace of growth in the Company's service area heightens the critical need to maintain quality of service and accentuates the importance, and the burden, of FPL's obligation to serve, especially in light of the potential challenges discussed above.

While providing an ROE that is sufficient to maintain FPL's ability to attract capital, even under duress, is consistent with the economic requirements embodied in the Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure a reliable energy supply. By the same token, customers also bear a significant burden when the ability of the utility to attract necessary capital is impaired and service quality is compromised.

Q. What evidence illustrates the benefits of maintaining FPL's ability to attract capital?

A. FPL's consistent ability to keep pace with the growing needs of its customers demonstrates the advantage that accrues to all stakeholders when the utility is able to maintain a strong financial position. In recent years, FPL has spent billions of dollars in order to implement the ambitious investment program required to add the new generation and transmission capacity dictated by the demands of a vibrant service area. The relatively large concentration of residential customers in FPL's service area also heightens the critical need to maintain quality of service and accentuates the importance, and the burden, of FPL's obligation to serve. Despite the associated complexities, FPL has effectively and economically responded to these challenges, in part due to its strong financial position. As Fitch concluded in a September 23, 2004 ratings credit report:

> FP&L has continued to improve operational performance and customer satisfaction during a period of considerable growth in its customer base.

The unprecedented hurricane season in 2004 also illustrates the benefits that accrue to a utility that has the financial wherewithal to respond to unforeseen events. After being hit by Hurricanes Charley, Frances, and Jeanne within two months, FPL's service territory experienced significant outages and damage, principally to the distribution system and some transmission lines. FPL restored service to nearly 5.4

million customers, which entailed replacement of approximately 13,200 poles, 11,100 transformers, and 1,700 miles of wire. While the balance in the dedicated storm reserve fund totaled about $354 million, $211 million of which consisted of cash, total expenses for FPL's storm recovery effort were estimated to be approximately $890 million, excluding power plant damage that was covered by insurance. Despite the extent of the damage and lack of sufficient reserves, FPL's strong financial and liquidity position ensured its ability to respond quickly and effectively to these unprecedented events. To meet such challenges successfully and economically, it is crucial that FPL continue to receive adequate support for its credit standing.

Q. What danger does an inadequate rate of return pose to FPL?

A. While FPL has been successful in maintaining its financial flexibility, experience demonstrates that investor confidence can evaporate almost overnight. Moreover, it is difficult to recover and the damage is not easily reversible. Consider the example of bond ratings. To restore a company's rating to a previous, higher level, rating agencies generally require the company to maintain its financial indicators above the minimum levels required for the higher rating over a period of time. Given the negative outlook currently assigned to FPL's long-term debt ratings, the perception of a lack of regulatory support would almost certainly lead to further downgrades. Moreover, the negative impact of declining credit quality on a utility's capital costs and financial flexibility becomes more pronounced as debt ratings move down the scale from investment to non-investment grade.

As discussed in the testimony of FPL's witnesses, FPL has done an outstanding job of meeting customers' power requirements reliably, efficiently, and at rates that compare favorably with other utilities. While FPL's conservative posture has benefited customers and provided a strong platform for continued success, actions that serve to erode financial strength or impair financial flexibility could have swift and damaging consequences. The cost of providing FPL an adequate return is small relative to the potential benefits that a strong utility can have in providing reliable service and fostering growth.

Q. What role does regulation play in ensuring FPL's access to capital is maintained?

A. Considering investors' heightened awareness of the risks associated with the electric power industry and the damage that results when a utility's financial flexibility is compromised, supportive regulation remains crucial to maintaining FPL's access to capital. Investors recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions. In a *RatingsDirect* report entitled "Regulation and Credit Quality in the U.S. Utility Sector" (Jan. 30, 2003), S&P noted that:

> When examining the quality of regulation, Standard & Poor's factors in what level of support the utility might get in times of distress, when its needs are most actute.

S&P went on to note the importance of financial flexibility, especially considering the capital markets' ability to constrict access to capital when investors' confidence is compromised. As S&P concluded, "[a]ttributes of a successful firm will include the ability withstand volatility and access to multiple sources of capital."

Investors recognize that regulation has its own risks. Considering the magnitude of the events that have transpired since the third quarter of 2000, investors' sensitivity to market and regulatory uncertainties has increased dramatically. As S&P

noted in an August 21, 2003 *RatingsDirect* report ("Electric Utility Blackout Puts Spotlight on Political and Regulatory Credit Risk"), the 2003 blackout is unlikely to ease investors' concerns:

> Clearly, the blackout has highlighted the complexity of the system, the diversity of its many stakeholders and the susceptibility of the industry to political and regulatory risk.

While investors recognize that the regulatory environment in Florida has been supportive, in some circumstances regulatory uncertainty can eclipse all of the other risk factors facing particular utilities. Indeed, the investment community has expressed concern that one outcome of the California crisis may be the perception that utility bankruptcy in times of distress is not an unreasonable outcome. But as S&P recognized in its January 30, 2003 *RatingsDirect* report, if such an attitude were to take hold, "the utilty industry would be exposed to capital market pressures" and investors "would either flee the industry or demand steep returns," which would ultimately drive up the cost of capital to customers.

Q. What other considerations highlight the need for supportive regulation?

A. Consider Docket No. 041291-EI, FPL's request to recover extraordinary storm-related costs, where the Office of Public Counsel ("OPC") has recommended disallowing reasonable and necessary expenses by forcing FPL's ROE to the 10 percent floor specified in the stipulation. In the aftermath of the crisis in western power markets in 2000-2001, perhaps the preeminent issue of concern to investors is the potential that regulators will prevent utilities from recovering reasonable and necessary expenses incurred to provide customers with reliable service. Investors perceive the expiration of the current stipulation and the resulting rate proceeding as one of the key risks confronting FPL. Because of the overhang of this impending rate case, investors' sensitivity to regulatory risks are particularly heightened, with the FPSC's actions being interpreted as a gauge of future regulatory support.

Moody's Investors Service noted in a February 1, 2005 *Credit Opinion* report that "[r]egulatory risk this year related to the 12/31/05 expiration of current rate agreement and hurricane cost recovery" posed challenges and observed that a "negative regulatory development" could lead to a ratings downgrade. Thus, while FPL's conservative posture and ongoing regulatory support have benefited customers and provided a strong platform for continued success, actions that serve to erode financial strength or impair financial flexibility could have swift and damaging consequences.

Q. Does your recommended cost of equity consider the impact that the potential for storm cost disallowances would have on investors' required rate of return?

A. No. The investment community has cited the FPSC's January 18, 2005 decision to permit the collection of deferred storm repair costs on an interim basis as a supportive and reassuring development for FPL's financial position. Similarly, Value Line's March 4, 2005 report informed investors that "[w]e think the regulators will grant full recovery" of FPL's storm costs. On the other hand, OPC's proposal to engineer a backdoor reduction in FPL's ROE through a novel reinterpretation of the stipulation would send an alarming message to investors – and one that is at odds with their current expectations.

The investment community is intensely focused on the actions of the FPSC, and denying utilities the ability to recover extraordinary costs, such as those related to the extreme storm season in 2004, would imply a dramatic increase in investment risk and required rate of return to FPL. Accordingly, if the FPSC were to adopt OPC's proposals in Docket No. 041291-EI, my recommended ROE would need to be adjusted upward to account for this additional risk.

Return on Equity Recommendation

Q. What then is your conclusion as to a fair rate of return on equity for FPL applicable to the 2006 test year?

A. As explained earlier, based on the various capital market oriented analyses described in my testimony, after incorporating a minimum adjustment for flotation costs I concluded that the fair rate of return on equity range for the electric utility proxy group was 10.3 to 12.3 percent. Considering the potential exposures faced by FPL and the economic requirements necessary to maintain access to capital even under adverse circumstances, it is my opinion that the reasonable ROE range for FPL coincides with the upper half of this range, or between 11.3 percent and 12.3 percent, with the midpoint being 11.8 percent.

Q. Does this recommended rate of return provide for or recognize any return for other factors?

A. No it does not. My 11.8 percent recommended fair rate of return does not explicitly incorporate any allowance for exemplary performance or efficient and economic management, as discussed in the testimony of FPL's witnesses. An incentive to recognize such factors should be added to my fair rate of return on equity for FPL.

Q. In evaluating the fair rate of return for FPL, is it appropriate to consider an incentive to recognize and encourage exemplary management?

A. Yes. As discussed in greater detail in the testimony of Mr. Dewhurst and other FPL witnesses, FPL has distinguished itself in numerous measures of operating efficiency and effectiveness while maintaining moderate electric rates. As a result, consumers and the service area economy have benefited from a climate of rapidly expanding service, efficient and cost-effective operations, excellent customer service, improved reliability, and prices that have declined in real terms. To date, the FPSC has helped to foster an environment in which customers are assured reliable service at reasonable rates, stockholders are fairly treated, and stakeholders are not forced to commit significant resources and bear the concomitant costs of multiple or annual rate cases.

Awarding an increment of return above the cost of equity, such as the 50 basis points proposed by Mr. Dewhurst, recognizes that FPL's superior management continues to be instrumental in achieving these results. Moreover, including an incentive for exemplary management above the minimum fair rate of return required by investors is entirely consistent with the incentive mechanism embodied in the stipulation in Docket No. 001148-EI, which provides for revenue sharing between FPL's customers and shareholders. As demonstrated in the testimony of Mr. Dewhurst, the payoff from achieving efficiencies and stimulating investment in the utility system is so large that the incremental impact of the reward for management effectiveness on the total cost of electricity to consumers pales into insignificance.

Q. What rate of return on equity is implied for FPL after incorporating an incentive for effective management?

A. Adding the 50 basis-point increment proposed by Mr. Dewhurst to my 11.8 percent recommended cost of equity results in a fair rate of return on equity of 12.3 percent. Giving effect to the 100 basis-point range typically allowed by the FPSC for regulatory purposes, this results in an appropriate fair rate of return on equity range of 11.3 to 13.3 percent.

Q. How does a return on equity of 12.3 percent compare with other benchmarks that investors would consider?

A. Reference to rates of return available from alternative investments of comparable risk can also provide a useful guideline in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This comparable earnings approach is consistent with the economic underpinnings for a fair rate of return established by the Supreme Court. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

The average Value Line Safety Ranking for the firms in the electric utility proxy group is "2". Value Line's projections (Jan. 28, 2005) indicate that its analysts expect that rates of return on shareholders' equity for the 283 firms in Value Line's universe assigned a Safety Rank of "1" or "2" will average 16.6 percent. Thus, the 12.3 percent rate of return on equity requested by FPL is well below the earned returns that investors anticipate for other firms of comparable risk, as measured by Value Line's Safety Rank.

Q. Does this conclude your direct testimony?

A. Yes.

ERRATA SHEET

(X) DIRECT TESTIMONY, OR ( ) REBUTTAL TESTIMONY (PLEASE MARK ONE WITH "X")
WITNESS: **William E. Avera**

PAGE #	LINE #	CHANGE
76	10	change year from "2004" to "2003".
33	19	insert "before December 1, 2004," between "higher" and "and".
74	14	insert "Pacific" between "Sierra" and "Resources".

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF MORAY P. DEWHURST

DOCKET NO. 050045-EI

MARCH 22, 2005

Q. **Please state your name and business address.**

A. My name is Moray P. Dewhurst. My business address is Florida Power & Light Company, Finance Division, 700 Universe Boulevard, Juno Beach, Florida 33408-0420.

Q. **What is your employment capacity?**

A. I serve as Senior Vice President of Finance and Chief Financial Officer of Florida Power & Light Company (FPL or the Company).

Q. **Please describe your duties and responsibilities in that position.**

A. I am responsible for the major financial areas of the Company, including the accounting and control functions, tax, treasury, budgeting and forecasting, and risk management. I oversee the establishment and maintenance of the financial plans, controls and policies for FPL. I am also responsible for establishing and maintaining effective working relations with the investment and banking communities, and for communicating the results of our operations to investors.

Q. **Please describe your educational background and professional experience.**

A. I have a bachelor's degree in Naval Architecture from MIT and a master's degree in Management, with a concentration in finance, from MIT's Sloan School of

Management. I have approximately twenty years of experience consulting to Fortune 500 and equivalent companies in many different industries on matters of corporate and business strategy. Much of my work has involved financial strategy and financial re-structuring. I was appointed to my present position in July of 2001.

Q. Are you sponsoring an exhibit in this case?

A. Yes. I am sponsoring an exhibit consisting of 1 document, MPD-1, which is attached to my direct testimony.

Q. Are you sponsoring or co-sponsoring any MFRs in this case?

A. Yes. I am sponsoring the following MFRs:

D-2, Cost of Capital – 5 Year History

D-3, Short-Term Debt

D-4a, Long-Term Debt Outstanding

D-5, Preferred Stock Outstanding

D-7, Common Stock Data

D-8, Financing Plans - Stock and Bond Issues

D-9, Financial Indicators – Summary

Additionally, I am co-sponsoring the following MFRs:

A-1, Full Revenue Requirements Increase Requested

B-14, Earnings Test

C-8, Detail of Changes in Expenses

C-41, O&M Benchmark Variance by Function

D-1a, Cost of Capital – 13 Month Average

D-4b, Reacquired Bonds

Q. Are you sponsoring or co-sponsoring any 2007 Turkey Point Unit 5 Adjustment schedules or any of FPL's 2007 Forecast schedules in this case?

A. Yes. I am co-sponsoring the following 2007 Turkey Point Unit 5 Adjustment schedules:

A-1, Full Revenue Requirements Increase Requested

D-1a, Cost of Capital – 13 Month Average

Additionally, I am co-sponsoring the following 2007 Forecast schedule:

D-1a, Cost of Capital – 13 Month Average

Q. What is the purpose of your testimony?

A. My testimony will support and supplement the testimony of Dr. Avera on the appropriate Return on Equity (ROE) that should be established in this proceeding, and it will present and support the proposed ROE performance incentive of 50 basis points and the appropriate capital structure for the Company. I will then discuss the drivers of the increase in insurance costs for FPL both historically and on a projected basis, as well as the need for an increase in the annual accrual for the Company's Storm Damage Reserve. Lastly, my testimony will support the need for a subsequent year base rate adjustment in 2007 to cover the revenue requirements associated with Turkey Point Unit 5 scheduled to be placed in service in mid-2007.

FPL'S CURRENT FINANCIAL CONDITION

Q. Please describe FPL's current financial position and credit profile.

A. Our current financial position is strong. FPL currently has high-quality investment grade ratings from the three major credit rating agencies. Standard and Poor's (S&P) maintains an issuer rating of "A" with a negative outlook for FPL. Moody's Investors Service (Moody's) has an "A1" issuer rating with a stable outlook. FitchRatings (Fitch) rates FPL unsecured debt at "A+" with a stable outlook. Additionally, both Moody's and Fitch rate FPL's secured debt at "Aa3" and "AA-," respectively, which is one notch higher than the issuer rating. FPL's strong financial position is confirmed in the financial markets by the extremely tight trading spreads of the Company's first mortgage bonds in the secondary market.

FPL's commercial paper program is currently rated "A-1/P-1/F1," providing excellent access to commercial paper at very attractive rates even when the financial markets are stressed. The commercial paper program provides FPL with the flexibility to respond to the unexpected and the ability to cushion the impact of any significant change on customer bills.

FPL's maintains a $1.5 billion credit facility to back up commercial paper issuance and support the credit requirements of the fuel hedging program.

Q. How do FPL's ratings and financial situation compare to the industry as a whole?

A. The industry has experienced a significant decline in credit quality over the past several years. The financial problems faced by California's utilities starting five years ago, the Enron debacle four years ago, the August 14, 2003 Northeast blackout, and the financial turmoil experienced by some of the non-regulated and regulated energy companies during the recent past have altered the views of rating agencies and investors with regard to the entire utility sector. This can be seen in the dramatic number of ratings downgrades that occurred during that time period. For example, S&P downgraded 81 utility holding companies and subsidiaries versus 29 upgrades in 2001 and downgraded an unprecedented 182 companies versus only 15 upgrades in 2002.

Although the ratings decline continued in 2003 with S&P downgrading 139 utility companies versus just 8 upgrades, the pace of downgrades slowed considerably as the industry began to stabilize. Many companies were successful in improving their liquidity position by refinancing bank facilities to push out near-term maturities and selling selective assets. According to an S&P report dated January 24, 2005, U.S. utility downside rating actions moderated significantly in 2004, with S&P recording only 33 downgrades of holding companies and operating subsidiaries, compared with 18 upgrades. The stabilization of the industry in 2004 was due to stronger balance sheets, rising free cash flow, improved liquidity, sizeable common stock issuances, expectations of sustained profitability, and a back-to-basics approach for certain companies.

In general, companies that over-extended and over-leveraged themselves, and/or those that took on excessive merchant generation or trading exposure in relation to their overall size, saw their credit positions suffer most significantly during this period. Additionally, companies that do not operate in constructive regulatory environments have seen their credits suffer as "ratemaking has become a more prevalent ratings driver in certain jurisdictions..... Regulatory rulings were meaningful factors in the downgrades of DTE Energy Co. (BBB/Stable/A-2) and IDACORP Inc. (BBB+/Stable/A-2)." (Standard & Poor's Research: U.S. Utility Downside Rating Actions Moderated Significantly in 2004 dated January 24, 2005). Companies that took on significant exposure in many foreign markets – in particular those in Latin America – also were negatively affected. On the other hand, some companies such as FPL whose investment programs have been well tailored to their available cash flow and balance sheet strength have been much less affected, as have those that have pre-emptively supported their growth plans through the issuance of new equity or equity-linked securities. As a result, today there is a wide range of credit and balance sheet strength in the industry.

FPL's ratings are towards the upper end of the industry range. As of December 31, 2004, approximately 35% of companies in the utility industry currently maintain ratings at a level of "A-" or above, 48% of the industry maintains ratings in the "BBB" category and 17% of the industry is rated below investment grade. (Standard & Poor's Research: U.S. Utility Downside Rating Actions Moderated Significantly in 2004 dated January 24, 2005).

Q. Why is it important to maintain a strong financial position?

A. The primary benefits of a strong financial position are flexibility and security. Flexibility is a crucial element of FPL's ability to manage risk. The statutory obligation to serve all customers at their desired level of demand, coupled with the uncertainty inherent in unforeseen events, means that FPL must go to the capital markets as service needs dictate rather than at the point in time that might be the most advantageous from a market perspective. The inability to time market entry is somewhat offset by a strong financial position. Balance sheet strength and flexibility are also manifested in the ability to absorb unexpected financial shocks.

A strong financial position also provides security. In this respect it acts much like insurance to provide security against relatively low odds but high negative outcome events. Unfortunately, FPL experienced such an event with last year's unprecedented storm season. However, our financial strength provided us with the market access to enable us to fund expenditures in excess of the Storm Damage Reserve without a detrimental impact to our overall credit position. Since the markets understand that FPL has ample coverage for events like these and anticipate ultimate recovery, they are willing to give us a certain degree of leeway. Of course, if ultimate recovery were ever in doubt, the market would not provide us this same degree of leeway.

Utilities, like other large corporations, generally depend on commercial paper to provide a large, inexpensive and liquid source of funds and to meet seasonal short-term cash needs. Investors in commercial paper generally rely on short-term ratings provided by the credit rating agencies. Companies with "A-1/P-1/F-1" ratings and above typically have excellent access to commercial paper, even during times of market stress. Companies with "A-2/P-2/F-2" ratings generally find a smaller pool of investors, as many investors are restricted to purchase only "A-1/P-1/F-1" paper. A smaller pool of investors typically indicates higher rates and reduced availability of funds. Some companies in our industry whose short-term ratings have fallen below "A-2/P-2/F-2" have been essentially shut-out from the commercial paper market as a source of short-term liquidity and forced to access more expensive bank markets and hold cash to fund short-term requirements.

Q. **How do customers benefit from FPL's strong financial position?**

A. FPL's strong financial position provides the Company with the financial flexibility necessary to fund the Company's long-term capital requirements as well as to meet short-term liquidity needs at an economical cost to customers.

Our strong financial position gives FPL excellent access to capital markets at attractive rates. For instance, FPL has issued over $1.2 billion of debt with coupon rates below 6% and maturities in excess of thirty years since December 2002 to retire higher cost debt and fund future capital requirements. Our credit spreads (the additional cost FPL pays in excess of U.S. Government securities) are among the lowest in the industry. Customers will benefit from these attractive debt financings for many years to come. In addition, the current forecast anticipates issuance of approximately $2 billion of new debt securities over the next several years to help finance capital expenditure requirements of approximately $5.2 billion and refinance maturing debt. The ability to support our extensive capital expenditure program requires access to capital. Customers benefit because we have this access at very attractive rates.

FPL maintains credit facilities to back-up its commercial paper program and trading obligations related to the fuel hedging program. This fuel hedging program is key to reducing the volatility of customer bills by locking in fuel prices for a portion of FPL's fuel requirements. The Company could not execute such a large program without extensive credit support. FPL's strong financial position enabled us to recently upsize our credit facility by $500 million to $1.5 billion to accommodate the recently expanded hedging program at extremely attractive rates. FPL's credit facility, combined with our current ratings and strong financial position, allow us to support collateral calls related to our fuel hedging program primarily with company guarantees and low-cost letters of credit instead of cash collateral required of many companies whose financial positions are weakened.

In addition to reducing the volatility of customer bills through the fuel hedging program, FPL has also been able to amortize $518 million of under recovered fuel costs over a longer period of time to lessen the immediate impact of rising fuel prices on customer bills.

Most recently, FPL was able to temporarily fund the deficiency in the Storm Damage Reserve without suffering significant financial consequences.

Our ability to take advantage of these options, which facilitated substantial cost savings and reduced rate volatility to our customers, is largely due to our strong financial position.

Q. What conclusion should the Commission draw about FPL's current financial position?

A. Our current financial position provides adequate financial strength and flexibility to accommodate the inherent uncertainties of the industry, taking due regard of the risk factors affecting the industry and the Company today, and is of benefit to our customers. It should be maintained through the provision of an adequate allowed return on equity and an appropriate equity ratio, as reflected in the recommendations made later in my testimony. Weakening in any of these areas would clearly be perceived by investors as a decline in our overall financial strength, thereby affecting our access to capital at reasonable rates at a time when external financing requirements will be substantial. This would increase financing costs as well as jeopardize the Company's ability to use its financial strength to reduce volatility in customer bills through activities such as fuel hedging or the extension of amortization periods for recovery of fuel costs and would ultimately undermine our ability to provide highly reliable service at costs below industry averages. The increase in base rates requested will ensure financial stability and continued financial viability.

RETURN ON EQUITY

Q. What is your recommendation for a return on equity?

A. I have reviewed the analysis performed by Dr. Avera and concur with his recommended fair rate of return on equity of 11.8%. In addition, we request that the Commission approve a performance incentive of 50 basis points to recognize the Company's superior performance and to provide an incentive for future superior performance. A performance incentive is fully warranted on the merits, and is consistent with past Commission action. Adding this performance incentive yields a midpoint for the allowed ROE of 12.3%, which is within Dr. Avera's fair rate of return range. A 1% band should be established on either side of the midpoint, resulting in a return on equity range of 11.3% to 13.3%.

Q. What should the Commission consider in determining the Company's ROE?

A. A company's ROE is an important indicator both of the economic return that the company can provide to its equity holders and the overall financial strength of the enterprise. It is axiomatic that any company must provide a prospective return to shareholders that is at least as good as the return that the shareholders could expect to earn on an investment of equivalent risk characteristics. Failure to do so will result in a loss of equity value and the inability to access capital markets at a reasonable cost. As I understand the Commission's task, it is, among other things, to look at risk through the eyes of current and potential equity investors and to set an allowed ROE that, if achieved by the Company, will induce the needed level of investment at the lowest reasonable cost and fairly compensate equity holders for the utilization of their assets. This level of ROE, if achieved by the Company, coupled with prudent management of the capital structure, will also satisfy investors' requirements for financial strength.

Investors' requirements at any particular point in time are set both by general conditions and risks and by company-specific conditions and risks. Virtually all conditions affect both debt holders and equity holders; however, they may affect these classes of investors differently. Therefore, the Commission should look to all the risk factors affecting a company when setting an allowed ROE, but should emphasize those that have the greatest impact on equity holders. In the following responses I have addressed these factors.

Q. What general risk factors should the Commission consider in determining the Company's ROE?

A. There are three general risk factors which should be considered. The first two factors have not significantly changed since the 1999 and 2002 rate proceedings, while the third risk factor is somewhat greater today than in past rate proceedings.

The financial success of most companies will be influenced by the growth rate of the economy, the inflation rate, and general unemployment levels. As I mentioned in my 2002 testimony, the economy began to experience a sharp slowdown starting in the second half of 2000 and into 2001, as businesses reduced spending and investment. The terrorist attacks in September 2001 prolonged the impact, and today uncertainties still exist from the war in Iraq. The active 2004 hurricane season creates further uncertainty due to the future possible adverse effects on tourism and the number of relocations to Florida. Economic events tend to have a disproportionate effect here in Florida, a tourist dependent state, which relies greatly on intangibles like consumer confidence as a driver of economic activity. Overall, this general risk factor has not changed significantly since 2002.

The second general factor is industry structural changes. From an investment perspective, *all* geographic areas have experienced an increase in uncertainty both because the future path of regulation is unclear and because the likely effects of a particular regulatory scheme are now understood to be much less predictable than previously thought. Although the regulated electric utility industry in Florida has not undergone significant restructuring, uncertainty surrounding the implications of FERC's Regional Transmission Organization policy and its potential impact on customers and utilities in Florida creates uncertainty in investors' eyes. Again, this general risk factor has not changed significantly since 2002.

The third general factor, which has increased the uncertainty and risk associated with the utility industry overall, is the changing nature of the industry. Changes in technology, uncertainty of long-term fuel supply, increased fuel price volatility, stricter environmental control regulations for items such as carbon dioxide and mercury, strained transmission grids and events such as the August 14, 2003 Northeast blackout augment industry risk and create an expectation that substantial investment will be required of regulated utilities in the foreseeable future. In a FitchRatings report titled "Outlook 2005: U.S. Power and Gas" published December 16, 2004, the Agency notes that it "expects capital expenditures for the regulated utilities and the generators over the next five years to increase above current industry projections. Higher expenditures will involve new investments for greater reliability of electric transmission and distribution systems as well as investments in gas storage and liquefied natural gas (LNG) terminal facilities. Also, electric utility operating companies and generators will face higher expenditures to meet stricter or new environmental standards for sulfur dioxide, nitrogen, mercury and greenhouse gasses."

Q. Please identify and describe company-specific risk factors that are important in determining FPL's ROE.

A. There are five company-specific risk factors that must be addressed in determining FPL's ROE:

Growth

The interaction of general economic uncertainty and the underlying strong growth of our service territory create a particular set of risks for FPL. We expect to continue to experience growth in the number of customers moving into our service territory; however, the recent hurricanes have forced us to lower our expectations and at the same time increase the range of outcomes that we must prepare for. While our expectations for customer growth in the short-term may be reduced, significant capital expenditures will still be necessary over the next few years to ensure adequate and reliable supply under a more uncertain range of outcomes.

All three rating agencies have expressed their concerns over the risk associated with these significant capital expenditures. In a report dated May 7, 2004, S&P stated that their concerns include "the need to construct new generation capacity to meet growth needs and reserve margins." Moody's lists "capital expenditures to remain high to meet demand growth and reserve margin requirements" as a risk/weakness for Florida Power & Light in an October 2004 report. FitchRatings lists "ongoing capital expenditure requirements" as a key credit concern for the Company in a September 23, 2003 report and states that "new generation investments will pressure customer rates" in a report dated February 4, 2005.

Customer Base

The majority of our revenues come from our residential and commercial customers. Compared to utilities in other states, Florida has a low industrial load. From an investor perspective, this reduces risk. There have been no major changes in our customer base over the last few years, so this risk factor remains the same as it has been for many years.

Florida Economy

As indicated earlier, the Florida economy has been particularly affected by the current economic uncertainty and the possibility of adverse effects from the 2004 hurricane season, in large part because of the heavy reliance on tourism. As a service provider to all segments of the Florida economy, we naturally absorb the consequences of this uncertainty, which from an investor perspective represents additional company-specific risk. While there has been no change in the level of risk exposure in this area, investor sensitivity to this risk has increased due to the heavy coverage of the storms by the media. At virtually every meeting with equity investors during the last several months they have focused on this issue.

Nuclear Generation

FPL has four nuclear generating units: Turkey Point Units 3 and 4 and St. Lucie Units 1 and 2. Together, these contribute 15.5% of available capacity and approximately 21% of actual supply, owing to their high reliability and their low-cost position in the economic dispatch. FPL has the highest percentage of generation from nuclear resources of any utility in the state. While our customers have enjoyed cost savings over the years from these units, the investment community assigns a higher level of risk to a utility that has nuclear units in its generating portfolio.

As discussed in Mr. Stall's testimony, recent events have caused an increase in the level of risk inherent in the nuclear industry. The Nuclear Regulatory Commission is taking a much more directive role in its oversight of the industry following the Davis-Besse incident causing concern over increased compliance costs for the industry as a whole. Additionally, heightened concerns surround the future of spent fuel storage due to continued controversy and lack of progress in the development of storage at Yucca Mountain. The delay in Yucca Mountain poses a risk to the industry, as nuclear plants are running out of room to store nuclear fuel on-site. Furthermore, security costs have increased due to the heightened level of concern over terrorist acts. Finally, while the license extension of many nuclear plants will clearly provide future benefits to both investors and customers, those benefits come with increased risk of large capital requirements for maintenance, as illustrated by the recent need for reactor vessel head replacements and steam generator replacements. These considerations are discussed further in Mr. Stall's testimony.

On a total cost basis (i.e., including depreciation and a fair allowance for capital recovery and assuming a risk premium for nuclear) our cost per kWh for nuclear-produced power is significantly less than the equivalent cost for fossil-fueled plants. Recent estimates of fuel cost savings alone, comparing the fuel costs of our nuclear and natural gas units, show that the nuclear units save approximately $1 billion per year in fuel cost. It would be an inconsistent use of the rate setting process to take advantage of the very large customer savings in variable cost without also compensating equity holders for the risk premium associated with nuclear power.

Geographic Position

Florida's geographic position combined with an increasing reliance on natural gas exposes the Company to certain additional risk factors related to gas supply. Currently, FPL obtains gas supply via one of two pipelines, Florida Gas Transmission or Gulfstream pipeline, both of which are sourced from the Gulf of Mexico. Disruptions of gas supply in the Gulf of Mexico due to a hurricane or other unforeseen event create additional risk in the eyes of investors and the rating agencies (S&P FPL Group Research Article dated October 21, 2003). This risk is partially mitigated through the use of fuel-switching capability, which has had the additional benefit of keeping fuel costs lower than they otherwise would have been. However, our dependence on natural gas has increased in recent years and will continue to increase as the Martin and Manatee and Turkey Point expansions are complete.

As discussed in our rate proceeding in 2002, Florida's geographic location exposes our electrical systems to a higher likelihood of adverse weather events. As evidenced in 2004, FPL's service territory experienced an unprecedented amount of storm activity, taking direct hits from Hurricanes Charley, Frances, and Jeanne. Concerns prevail over whether we may be entering into a more active hurricane period over the next few years and uncertainty prevails regarding the potential impact of El Nino/Southern Oscillation on future adverse weather events. While the Storm Damage Reserve has historically provided substantial mitigation of this risk, investors are still at risk for loss of revenues and other impacts during adverse weather conditions. All other factors being equal, Florida's greater likelihood of adverse weather events increases risk. Should the Commission deviate from its past policy and practice in allowing the recovery of prudent and reasonable storm restoration costs, risks to investors would significantly increase beyond the level that has been factored into the ROE submitted by FPL in connection with its request for an increase in base rates.

Q. What conclusion should the Commission draw from these qualitative risk factors?

A. I believe it is important for the Commission to be aware of these risk factors as it considers both the appropriate level of ROE and the capital structure that we have maintained at FPL. Clearly, an analysis of the risk factors indicates that FPL operates in a riskier environment today than in 1999 and 2002. In my judgment, Dr. Avera has appropriately evaluated the impact of these uncertainties on investors' willingness to supply capital and considered the implications for FPL's financial integrity. An 11.8% ROE would fairly account for the exposures that investors attribute to FPL, while ensuring the Company's ability to attract capital even under adverse circumstances, assuming no material deviations in the regulatory framework, particularly as it relates to the recovery of excess storm restoration costs.

ROE PERFORMANCE INCENTIVE

Q. Please explain the ROE performance incentive sought by the Company in this proceeding.

A. FPL is requesting that the Commission increase the midpoint of the Company's authorized ROE band by 50 basis points to 12.3%. The purpose of the incentive is to recognize FPL's past superior performance and to encourage continued strong operational performance over the long-term. Such an action has the additional benefit of providing a signal to other companies that outstanding performance will be encouraged, recognized and rewarded.

Q. Why would a performance incentive be necessary given the Company's obligation or duty to serve?

A. The obligation or duty to serve requires that the Company be physically and financially capable of providing electric service to all those within a certain geographic area who request it, and to meet that demand with adequate and reliable resources. In return, a utility is entitled to "just and reasonable" rates that provide a return of and on its investment. This regulatory regime generally has worked very well in the United States, producing utility systems and services that are among the most modern, efficient and reliable in the world. However, traditional cost-of-service based regulation has a shortcoming in that it fails to provide incentives for utilities to achieve more efficient levels of service over a long period of time. Instead, the primary incentives are to avoid challenges by regulators or intervenors, which is not conducive to attempts to reach higher levels of cost-effectiveness.

To illustrate this point, consider two hypothetical utilities. Utility A plans and operates its system in a way that is principally intended to avoid adverse regulatory consequences such as imprudence disallowances. It operates with adequate reliability, but it attains that reliability primarily through volume of spending, not through process innovation. Its spending is clearly not imprudent, yet its overall cost-effectiveness is inferior to industry averages. Utility B, on the other hand, sets high standards for both reliability and cost levels. Over time, through process improvements and innovation, it is able to reduce the level of cost needed to attain top quartile reliability. Assuming the two utilities had similar service territories, load profiles, risk profiles, and other characteristics, and were entitled to the same ROE range, "just and reasonable" base rates for Utility A would be higher than for Utility B. Yet Utility B, a better managed utility producing lower base rates and better overall service for customers, earns no more than Utility A. It is therefore clear that conventional ratemaking provides no incentive to encourage companies to seek to become "Utility B." Yet, as in every other field of human endeavor, it is always easier to adopt the "safe" path of adequate but not outstanding performance.

Q. Is it your impression that certain utilities explicitly choose to plan and operate their systems at minimum acceptable levels?

A. No. I have no reason to believe that such an approach would be contemplated by or acceptable to any particular management team. Nevertheless, it is obvious that, for whatever reason, there is a gradation of performance levels among investor-owned utilities throughout the country. The point of my example is simply to indicate the need for some variation on conventional rate of return regulation to promote and reward better operational performance which ultimately benefits customers. The difference to customers between "adequate" (e.g. industry average) and "outstanding" performance is very substantial, yet conventional regulation offers little inducement to companies to accept the risks involved in seeking outstanding performance.

Q. **Has the Commission employed alternatives to conventional cost-of-service based regulation?**

A. Yes. This Commission has approved such alternative regulatory approaches in the past. Specifically, in the case of FPL, the Commission has approved revenue sharing plans in 1999 and in 2002. Under these plans, the current of which expires at the end of 2005, the Company has operated under certain revenue sharing thresholds, providing refunds to customers where those thresholds were exceeded due to unusually hot weather, for example, but being allowed to enhance its earnings through efficient management without reference to an ROE ceiling. The results of these two agreements have been very positive from the standpoint of customers. Since 1999, FPL has been able to lower its retail base rates by $600 million in annual revenue requirements and has provided refunds of more than $220 million, which will result in a total of nearly $4 billion in direct savings to customers through the end of 2005.

Although these revenue sharing agreements have provided positive benefits to customers, today, with utilities generally having to make very large investments in infrastructure to continue providing reliable service and facing other significant cost increases, such agreements hold much less appeal. Therefore, some other type of incentive mechanism would be appropriate.

Q. **In what specific ways has the Company earned the opportunity for an incentive of this nature?**

A. The Commission should evaluate FPL's performance in three key areas:

1. Reliability of Service
2. Quality of Customer Service
3. O&M Costs

Other witnesses in this proceeding will testify in detail about the Company's specific achievements in each of these areas. I will indicate who these witnesses are with a brief comment and then go on to discuss the magnitude of the performance incentive and the potential impact on customers. I should point out that there is an independent source that the Commission should consider when examining these areas, namely Mr. Landon's testimony.

Q. **Please comment on the Company's achievements in reliability.**

A. The focus here should be on the excellent reliability of our operating system: generating, transmission, and distribution. The Company's fossil and nuclear availability rates are above the industry average and the average amount of time customers were without power in 2003 was less than half the industry average. Additionally, in 2003 and 2004, FPL's results for average annual outage time, as measured by the System Average Interruption Duration Index (SAIDI), were the best in Florida. In their testimonies, Witnesses Stall, Yeager, Mennes, and Williams provide the specifics of these achievements within their respective areas.

Q. **Please comment on the Company's achievement in quality of customer service.**

A. FPL has improved an already excellent record of customer service with, for example, our state-of-the-art Customer Care Centers. FPL earned the prestigious Center of Excellence certification from Purdue University's Center for Customer-Driven Quality - the first electric utility to be so honored and was awarded the ServiceOne award by PA Consulting a leading management, systems and technology consulting firm that recognizes utilities that provide exceptional service to their customers as determined by a set of measures of excellence in customer care developed by a panel of industry experts. These achievements are detailed in the testimony of Mrs. Santos.

Q. **Please comment on the Company's achievement in controlling O&M costs.**

A. As outlined in the Company's test year letter, FPL achieved unprecedented reductions in operating expenses during the decade of the 1990s. Since 1985 the Company has succeeded in lowering its non-fuel O&M expenses per kWh by approximately 29%, while the number of customers served through 2003 increased by 57%. During the decade of the 1990s, FPL actually reduced total annual non-fuel O&M by over 15%. After a decade of steady reductions, costs have grown only modestly over the last few years despite the increased costs of nuclear maintenance, healthcare, and insurance.

Q. **Does the Company expect an increase in its O&M expenses in 2006?**

A. Yes, but O&M costs per kWh are still at low levels, especially compared with industry averages. As indicated in Mr. Landon's testimony, FPL's average O&M expenses over the six-year period beginning in 1998 were 41 percent lower than the benchmark group on a per customer basis, and 22 percent lower on a per kWh basis. The current and prospective cost pressures – driven to some extent by unusual economic circumstances – should not obscure the much larger overall point, which is the huge magnitude of the overall performance improvement over the last decade. FPL has a consistent track record of achieving O&M costs per kWh that are well below the industry average. Had FPL not undertaken these extraordinary expense reductions, the level of expense included in test year calculations would have been much higher. Furthermore, the current upward pressure on O&M costs is common to the industry, mainly due to increased nuclear costs, employee benefits, and insurance. What FPL seeks to be acknowledged for is the exceptionally low base on which test year expenses are built.

Q. **Why do you recommend that the performance incentive be 50 basis points?**

A. A performance incentive should be large enough to motivate FPL's continued performance improvement over the long-term, yet not so large as to negate the benefits of performance improvements for the customer. A 50 basis point performance incentive equates to approximately $50 million in revenue requirements.

One way to evaluate the annual benefits customers receive from FPL's performance improvements is to compare FPL's performance in major cost areas to an industry or peer group average and calculate the impact to customers if FPL simply operated at the cost and efficiency levels of the industry average versus the actual levels attained. Fuel costs are set by the market and beyond FPL's control, however; O & M and capital costs are a substantial portion of the total cost customers pay for electricity. As illustrated in Mr. Landon's testimony, FPL's O&M and gross plant have consistently been significantly lower than the average for its peer group on both a kWh and per customer basis. In other words, FPL has consistently collected less money from customers for the operation and maintenance of plants, depreciation, financing costs and investor return than its industry peer group. If FPL had operated based on the peer group average, costs for O&M and depreciation alone during the 1998 through 2003 period would have averaged approximately $400 million higher per year (calculated on a per kWh basis). See Exhibit MPD-1. The savings are even more significant on a per customer basis. This estimated savings does not account for the cost of capital associated with the increase in rate base. A 50 basis point performance incentive equates to roughly 13% of the annual average cost savings.

Q. Would customers continue to benefit from lower costs if the Commission granted FPL's request for a rate increase in this docket?

A. Yes, even with the rate increase requested for 2006 and the supplemental adjustment requested for Turkey Point Unit 5 requested for 2007, FPL's O&M costs and gross plant balance (expressed on a cents per kWh basis) are lower than customers in FPL's peer group average for 2003. See Exhibit MPD-1.

As mentioned earlier, FPL's customers will have realized direct savings of almost $4 billion as of December 31, 2005, as a result of the two rate reductions and associated refunds implemented by the Company. The efforts of a strong management team and a quality-driven workforce have succeeded in delaying as long as possible increases in FPL's retail base rates, while keeping pace with Florida's rapid growth and demand for power. After many years, an increase in retail base rates now is necessary to ensure that FPL can continue to provide reliable, cost-effective electric service at the levels its customers have come to expect and that are consistent with the Company's past record of performance.

Q. What does FPL's proposed performance incentive imply for allowed ROE?

A. As noted earlier, the addition of a proposed 50 basis point performance as an incentive to recognize the superior management performance that the Company has achieved over a sustained period of time and a method to encourage FPL management to continue this exceptional performance leads to our recommendation of a midpoint allowed ROE of 12.3%. A 1% band on either side of the midpoint should be established. Therefore, I recommend a range of return on equity of 11.3% to 13.3%.

Q. What would be the impact of the performance incentive on FPL and other companies subject to the Commission's jurisdiction?

A. A performance incentive that shifted the allowed range up 50 basis points would be a positive incentive for the Company to continue its excellent performance. At the same time a performance incentive to FPL would be an important signal to other companies as to the importance of, and the Commission's willingness to recognize, performance and service achievements in establishing a utility's rates. In Docket No. 010949-EI, Commission rewarded Gulf Power Company (Gulf) with a 25 basis point adder to the mid-point ROE in recognition of Gulf's past performance and as an incentive for Gulf's future performance. Without commenting on whether a 25 basis point adder was sufficient in light of Gulf Power's achievements, I believe a 50 basis point adder is a relatively modest award considering FPL's track record and the amount of value the Company's efforts have realized for customers.

CAPITAL STRUCTURE

Q. What is FPL's current equity ratio?

A. Since the 1999 Revenue Sharing Agreement took effect we have maintained our equity position over time, on an adjusted basis, at approximately 55.83%, though the pattern of seasonal cash flows may drive the ratio slightly up or down on a short-term basis.

Q. What is your recommendation for an equity ratio for FPL for regulatory purposes?

A. I recommend maintaining the adjusted equity ratio of 55.83%, which was established in FPL's 1999 Stipulation and Settlement Agreement (the Revenue Sharing Agreement) between FPL and the Office of Public Counsel that was approved by the Commission and was sustained in FPL's 2002 Stipulation and Settlement. As provided in both of the agreements, the adjusted equity ratio equals common equity divided by the sum of common equity, preferred equity, debt, and off-balance sheet obligations. Nothing has happened in the interim that would suggest that the ratio should be reduced, and in fact the current industry status would tend, if anything, to drive the required ratio in the opposite direction. It would certainly be inconsistent for the Commission to seek to reduce the financial strength of the Company at a time when many key risk drivers point to a period of increased risk. However, I believe that an adjusted equity ratio of 55.83% provides adequate financial strength for the current environment.

Q. Please explain your reference to FPL's equity position on an adjusted basis.

A. In evaluating the adequacy of the capital structure of any company, investors will take into account major financial commitments, whether these are reflected on the balance sheet or not. In the case of a utility that has an obligation to serve its customers, the financial community commonly takes into account obligations associated with purchased power agreements (PPAs). This fairly acknowledges the fact that a long-term contractual commitment to purchase firm capacity behaves economically much like debt, imposing fixed charges independent of a company's revenues and, thus, should be taken into account in evaluating the financial strength of the company.

In the case of FPL, we have several long-term purchase contracts that supply about 20% of the energy we sell to our retail customers. These obligations significantly increase the fixed charge leverage of the Company and are generally understood by the investment community. They are explicitly evaluated by the rating agencies, who examine each contract and assign it a rating that dictates how much of the nominal total value of the contract will be added to FPL's debt obligations for rating purposes. The net effect is to increase the relative share of debt and debt-like instruments in the capital structure. Accordingly, FPL will need to maintain a higher unadjusted equity ratio to attain the same level of financial security with PPAs than without.

Q. **Please describe the basic methodology employed to determine the amount of imputed debt.**

A. While all of the rating agencies take off-balance sheet obligations into account when evaluating credit quality, S&P uses an approach that has both quantitative and qualitative aspects to value the debt component of off-balance sheet obligations. It involves first computing the net present value of the remaining capacity payments under the contract. A risk factor is then determined based primarily on the method of recovery of capacity payments. Once the risk factor is determined, it is then multiplied by the net present value of the remaining capacity payments to determine the amount of off-balance sheet obligation to include as debt in the capital structure of the company for purposes of analyzing credit quality.

Q. Do you believe an adjustment of this type is appropriate?

A. Yes. In general I agree with the judgment of the financial community that an adjustment for off-balance sheet obligations should be made in assessing the financial condition of a utility. In addition, while our own calculation of the appropriate amount to include might be different, I believe that the rating agencies' overall assessment fairly represents the general investor viewpoint and is thus directly relevant. It is therefore reasonable for the Commission to make a comparable adjustment when it evaluates the financial strength of FPL.

Q. Why is it important that regulatory policy be consistent with the perspective of the financial community on this issue?

A. There are two reasons. First, as I understand the goals of regulatory policy, one of the Commission's tasks is to set rates such that investors have the prospect, though not the guarantee, of earning a reasonable rate of return. In doing so, the Commission must look to capital markets for evidence of investor requirements. Rating agencies, acting as independent risk assessors on behalf of investors generally, are an important source of evidence in this regard. The fact that they include off-balance sheet obligations should be strong evidence of the relevance of these obligations to financial risk.

In addition, however, there are sound fundamental economic reasons for viewing purchased power obligations as part of the financial profile. These obligations are similar to debt from a financial perspective. Moreover, they represent avoided capacity – capital expenditures and rate base that would otherwise have been included like other assets – but with a fixed obligation. Whereas all other assets are supported by a cushion in the form of the most junior financial claim (common equity), which bears the ultimate risk of financial fluctuations, these PPAs have no such support. The Company is required to meet these obligations and cannot, in a weak year, return less than the contractual commitment. From the Company's perspective, it is as though the capacity represented by these contracts were 100% financed by debt. The major bond rating agencies include a portion of the present value of these contracts as debt in their analysis. Logically, this effect should be incorporated into the overall assessment of financial structure.

Q. **Has the Commission previously recognized the financial market's imputation of debt in assessing the impact of purchased power on a utility's capital structure?**

A. Yes. The Commission continues to recognize the financial leverage implicit in purchased power contracts in the approach used for surveillance reporting requirements. The current revenue sharing agreement in effect for FPL included in Order No. PSC-02-0501-AS-EI, April 11, 2002, incorporates by reference the following provision from the Stipulation and Settlement approved by the Commission in 1999 (Order No. PSC-99-0519-AS-EI, March 17, 1999):

> (FPL's) adjusted equity ratio equals common equity divided by the sum of common equity, preferred equity, debt and off-balance sheet obligations.

The amount used for off-balance sheet obligations will be calculated per the Standard & Poor's methodology as used in its August 1998 credit report.

The Commission has also allowed consideration of imputed debt in approving FPL's Standard Offer Contract. More recently, the Commission has recognized this concept in accepting applications of an equity adjustment in Docket No.031093-EQ, *In re: Petition for approval of revised standard offer contract and revised COG-2 rate schedule by Florida Power and Light Company*, Order No. PSC -04-0249-TRF-EQ, dated March 5, 2004, and in Docket No. 040206-EI, *In re: Petition to determine need for Turkey Point Unit 5 electrical power plant, by Florida Power and Light Company*, Order No. PSC-04-0609-FOF-EI, dated June 18, 2004.

Q. How do the capital markets react to an adjusted equity ratio of 55.83% compare?

A. The capital market's reaction is positive - both the debt and equity markets react well. The market reaction supports our current ratings and overall credit profile as evidenced by the tight trading spreads on FPL's bonds in both the new issuance and secondary markets. FPL's performance and access in the market is good and is consistent with the strong end of the industry.

Q. What can you conclude about FPL's current adjusted equity ratio?

A. Our 55.83% equity ratio has been and continues to be well received by the markets. Maintaining this adjusted equity ratio will indicate to the Capital Markets the Commission's continued commitment to support the financial integrity of the service providers subject to its jurisdiction. Furthermore, a strong capital structure is appropriate to current circumstances and offers flexibility and security, which enables us to serve our customers well.

STORM DAMAGE FUND

Q. What has FPL proposed as the annual accrual to the Storm Reserve to be reflected in base rates?

A. FPL has proposed that the Commission establish a target reserve level of $500 million and that the annual accrual in base rates be increased to $120 million. This amount includes $73.7 million, approximating the expected amount of annual storm losses, based on Mr. Harris' analysis. The remainder of the $120 million annual accrual would contribute toward the replenishment of the depleted storm reserve. Assuming an annual accrual of $120 million and a two year surcharge recovery of any negative storm damage reserve balances, the expected balance of the Storm Reserve would be approximately $367 million after five years, according to Mr. Harris' analysis.

Q. What regulatory framework underlies this request?

A. I believe the Commission has established and consistently endorsed an overall framework that acknowledges that the costs associated with restoring service after tropical storms are a necessary cost of doing business in Florida and as such are properly recoverable from customers. This framework consists of three main parts: (1) an annual storm accrual, adjusted over time as circumstances change; (2) a storm damage reserve adequate to accommodate most but not all storm years; and (3) a provision for utilities to seek recovery of costs that go beyond the storm reserve. These three parts act together to allow FPL over time to recover the full costs of storm restoration, while at the same time balancing competing customer interests: as small an ongoing impact as possible; minimal volatility of "rate shock" in customer bills because the reserve is insufficient; and intergenerational equity. This balance requires periodic adjustment in the main components of the framework – the annual accrual and the target reserve balance – in light of changing storm experience and the growth of FPL's T&D network. The annual accrual can be reduced if a period of favorable loss experience leads to a build-up in the storm reserve above the target level, while, conversely, a period of unfavorable loss experience will lead to depletion of the reserve and a need to increase the rate of annual accrual.

Q. If the regulatory framework did not provide for the full recovery of storm restoration costs over time, would your proposed annual accrual be the same?

A. No. The proposed annual accrual assumes FPL has the ability to recover prudently incurred storm restoration costs, whether there is a deficit in the Storm Damage Reserve or not. If FPL were not permitted to recover prudently incurred storm restoration costs, we would need to modify our accrual and overall rate request. The annual accrual would need to recover the annual expected cost of storm restoration, plus provide for the build-up of substantial reserves that could withstand an extreme storm season. In addition, investors would need to be compensated for the additional risk capital that would be required to assume an insurance function with increased returns.

Q. Why should customers pay for storm restoration costs? Isn't this a risk of doing business for FPL?

A. To address these questions, one must first recognize that they embody two distinct concepts: cost and risk. In fact, from a business perspective, the primary risk around tropical storms is simply their timing. We _will_ incur costs to restore power after tropical storms and what is at issue here is the treatment of those entirely foreseeable _costs_ of restoring power after a tropical storm. These costs are an integral part of the cost of providing electric service in Florida, a region susceptible to tropical storms and hurricanes. As such, they are legitimately recoverable from customers under basic principles of regulation.

At present we do not recover (and have not recovered since Hurricane Andrew) through base rates the full expected costs of restoring service after tropical storms. Nor do we recover through base rates the amounts that would be necessary to compensate for the risk capital that would need to be supplied were investors to assume an insurance function. There is a good reason we do not do so: the current regulatory framework is a much less costly means of attaining the same end. But an integral part of that framework is the ability of the utility to recover prudently incurred costs in excess of whatever storm reserve balance happens to exist at the precise moment that hurricanes strike, for while the long term expected costs are relatively predictable, the adequacy of this balance is inevitably a matter of chance.

Q. **How is this different than, for example, an accident at one of FPL's generating plants?**

A. In many respects it is not. It is true that even an organization such as FPL, with a good track record, will from time to time incur losses from accidents. These losses are a part of the cost of providing electric service and as such a fair average level of costs is reasonably recoverable from customers. The fundamental difference, however, is that extraordinary losses from plant outages are covered by insurance, the cost of which is recovered through base rates. So, the costs of such extraordinary losses, effectively, are borne by customers. This is not the case today with storm costs, since commercial insurance is unobtainable at reasonable expense.

Q. **Why doesn't FPL purchase insurance for storm losses?**

A. The substantial losses associated with Hurricane Andrew in 1992 essentially eliminated the commercial market for storm insurance in anything like the amounts needed to provide adequate protection to FPL's extensive network of assets and its ability to quickly restore reliable service. Though FPL continues to explore the market for insurance for storm damage losses, it has been forced to seek other methods to ensure that it would have adequate available resources for the costs of repairing and restoring its T&D system in the event of a hurricane, storm damage, or other natural disaster.

Q. How has FPL paid for storm damage repairs and restoration since 1993?

A. Following Andrew, FPL, with the Commission's approval, over time developed an approach that relied more heavily on the Storm Damage Reserve, the existence of which pre-dated Andrew. In 1993 FPL initially proposed a perpetual storm clause, but this was rejected by the Commission at that time. Instead, the Commission endorsed the composite approach I discussed earlier. We have consistently applied this framework ever since.

Q. Has this framework operated effectively in your view?

A. Yes. Since Hurricane Andrew the current framework has operated to keep customer rates lower than they otherwise would have been, since the annual accrual has been significantly less than the expected annual costs of restoration, even while the Storm Damage Reserve increased. However, this has only been possible because of the very favorable storm experience over the last decade. Simply put, Florida has been fortunate, and thus the restoration costs actually incurred over this period -- which have all been funded by the Storm Damage Reserve even while that reserve has increased -- have been well below the long-run expected values. Thus, until this year, FPL has never had to call on the third part of the framework, the right to petition for relief in the event the reserve is exhausted.

Q. After three hurricanes hit FPL territory in the unprecedented 2004 storm season, was the Storm Damage Reserve adequate to cover storm restoration and repair costs?

A. No. The current estimated cost for all three storms, net of insurance proceeds is $890 million (total system). Payment of these costs has completely depleted the Storm Damage Reserve of $354 million as of December 31, 2004 and created an approximate $533 million (jurisdictional) deficit in the reserve.

Q. Does this indicate a failure in the current regulatory framework?

A. No. The current framework contemplated the potential that the existing Storm Damage Reserve would not be sufficient to cover restoration costs in all circumstances. What it does indicate is that the annual accrual was not set sufficiently high, resulting in the need for the type of special assessment contemplated by Order No. 93-0918, and requested by the Company in Docket No. 041291-EI, in light of the extraordinary storm season of 2004. Higher levels of annual accruals prior to 2004 would obviously have meant a higher Storm Damage Reserve going into 2004 but would also have meant higher rates during that time.

Q. Explain FPL's proposal to recover the deficit.

A. FPL has requested Commission approval in Docket No. 041291-EI to recover the deficit through a monthly customer surcharge. The Commission authorized FPL to implement the storm surcharge effective February 17, subject to refund pending the outcome of hearings scheduled in April 2005. Another potential option for the recovery of the storm deficit is the issuance of securitized bonds. This option would require legislative action as well as the issuance of a financing order by the Commission, and my testimony is not predicated upon a securitization approach.

Q. **If FPL's request to recover the deficit in the Storm Damage Reserve in Docket No. 041291-EI is approved, will you still need to increase the annual accrual to the Storm Damage Reserve?**

A. Yes. Recovery of the current deficit in the Storm Damage Reserve would put the Reserve back to zero. The current annual accrual of $20.3 million is not, and has not been for some time, sufficient to cover expected annual storm losses. With the depletion of the Storm Damage Reserve from the 2004 hurricane season, the annual accrual must now not only fund annual expected losses (because there are no existing reserves to rely on), but also contribute to the rebuilding of the Storm Damage Reserve to a prudent level over a reasonable period of time.

Q. **What are the fundamental regulatory objectives that should be considered in establishing the annual storm accrual and target reserve balance?**

A. FPL believes that the regulatory objectives should be the following: (1) achieve the lowest long-term customer costs; balanced with (2) dampen volatility of the reserve (i.e., reduce reliance on special assessments/rate increases); and (3) cover the costs of most storms, but not those from the most catastrophic events.

Q. **How should the Commission determine the appropriate level of annual accrual?**

A. Assuming that the current deficit in the storm fund is recovered through a special surcharge, and that the regulatory framework continues to provide for the recovery of prudently incurred storm costs in excess of storm reserves in periods of high storm activity, the goal of the accrual over the next several years should be to cover the expected value of annual windstorm losses and make some progress in reestablishing the Storm Damage Reserve to a level adequate to fund most but not all windstorm losses. On the other hand, if the current deficit in the Storm Damage Reserve is not recovered from customers or the prospective regulatory framework were altered in a way that did not provide for the recovery of prudently incurred storm costs in excess of the Storm Damage Reserve in periods of high storm activity, FPL would have to reevaluate both the level of the annual accrual requested in this filing as well as the overall required investor return.

Q. Has FPL performed a study to determine the annual amount of expected losses from windstorms?

A. Yes. FPL commissioned studies to calculate the annual amount of expected windstorm losses, as well as the expected value of the storm fund given various funding levels. The studies were prepared by and are being sponsored by Mr. Harris of ABS Consulting.

Q. What direction was provided by FPL to ABS Consulting in the preparation of the studies?

A. FPL requested that ABS Consulting determine the levels of losses to which the Company and its customers are statistically exposed and to develop average annual cost estimates associated with repair of storm damage and service restoration over a long period of time. Additionally, FPL requested ABS to provide a probabilistic analysis of expected results for the Storm Damage Reserve Balance over five years at various levels of annual accrual.

Q. What does the analysis conclude regarding the expected annual long-term cost for service restoration and repair of storm damage to FPL's assets?

A. The ABS Consulting analysis concludes that the expected average annual cost for windstorm losses is approximately $73.7 million. Windstorm losses include costs associated with service restoration and system repair of FPL's Transmission and Distribution (T&D) system from hurricane, tropical and winter storm losses. Also included are storm staging costs and windstorm insurance deductibles attributable to non-T&D assets. The $73.7 million expected annual loss is obviously much greater than the current approved $20.3 million annual accrual, which has not been sufficient to cover expected annual losses for some time.

Q. Does the analysis recommend a target reserve level?

A. No. There is no single correct target reserve balance. The target reserve level depends largely on the regulatory framework for storm cost recovery and the point at which the Commission decides to balance the customer interests that I referred to earlier. Obviously, the lower the Storm Damage Reserve balance, the more likely that storm losses will exceed the funds available in the Storm Damage Reserve and therefore the greater the reliance on special assessments. The higher the Storm Damage Reserve Balance, the less likely windstorm losses will exceed the funds available in the Storm Damage Reserve. If the regulatory framework were to be changed such that FPL could not recover prudently incurred restoration costs in excess of the Storm Damage Reserve, then the balance in the Storm

Damage Reserve would have to be maintained at substantially higher levels to ensure that FPL could recover the full cost of providing electric service over the long-term.

Q. What target reserve level does FPL recommend?

A. Under the assumption that the regulatory framework would provide for recovery of prudently incurred costs that go beyond the Storm Damage Reserve (in other words, continuing the Commission's existing policy) a target reserve level should be set that is large enough to withstand the storm damage from most but not all storm seasons. FPL recommends a $500 million target reserve level. According to the aggregate damage exceedance probabilities presented in Table 5-2 on page 5-6 of Mr. Harris' Storm Loss Analysis, Document SPH-1, the chance that losses over five storm seasons will exceed $500 million in any one of those seasons is approximately 23.6%.

Q. Will an annual accrual of $120 million ensure that there will be adequate funds in the Storm Damage Reserve to cover all windstorm losses?

A. No. The analysis indicates that even with an increase in the annual accrual to $120 million and the ability to recover a storm deficit through a two-year surcharge, there is still a 33% chance that losses will exceed the value of the Storm Damage Reserve over a five year period. Additionally, the assumptions used to develop the expected annual loss from windstorms did not take into account any increase in restoration costs due to inflation or future customer growth, much of which is projected to occur in coastal areas most susceptible to windstorm damage.

While there is a significant probability that an annual accrual of $120 will not be sufficient to cover all windstorm losses, it provides a reasonable level of coverage and, I believe, fairly meets the objectives stated by the Commission in Order No. PSC-95-1588-FOF-EI:

> "The annual accrual needs to be sufficiently low so as to prevent unbounded storm fund growth and yet large enough to reduce reliance upon emergency relief mechanisms in the event of catastrophic weather events."
>
> Order No. 95-1588-FOF-EI, issued December 27, 1995 in Docket No. 951167-EI, page 2.

Q. How can the Company ensure that the requested annual accrual of $120 million would prevent unbounded growth?

A. FPL proposes to file updated studies at least every five years for review by the Commission. Based on the ABS Consulting analysis, at an annual accrual level of $120 million, the probability that the storm fund will exceed $500 million in five years is approximately 39%, and there is a 5% chance that the reserve would reach approximately $634 million after five years, at which time the annual accrual and appropriate reserve level could be reevaluated.

Q. Has the Commission allowed for a 5-year review of other funded reserves?

A. Yes. For example, the Commission currently requires FPL to file a study that allows the Commission to review its nuclear decommissioning costs at least every five years.

Q. Can FPL change its storm fund accrual without Commission authorization?

A. No.

Q. Can funds collected from customers for storm restoration be used for any other purpose?

A. Funds collected can be used for any allowed purpose of the fund including costs associated with service restoration and repair of FPL's T&D system as a result of hurricanes, tropical storms and winter storms, storm staging costs, windstorm insurance deductibles attributable to non-T&D assets, and payments of nuclear retrospective premiums.

INSURANCE COSTS

Q. According to Mr. Stamm, insurance cost increases are a significant driver of increased operating and maintenance costs for FPL. What types of insurance costs is he referring to?

A. Mr. Stamm is referring to non-nuclear property insurance, nuclear and non-nuclear injuries and damage liability, nuclear property insurance, and nuclear outage insurance.

Q. How much are these insurance costs expected to increase from 2002 to the 2006 test year?

A. Insurance costs are expected to increase from a negative expense (i.e., contribution to income) of $10.0 million in 2002 to an expense of $20.6 million in 2006. This is an increase of approximately $30.6 million over this 2002-2006 time period, with approximately $24.5 million of the increase occurring in the

2002 through 2004 time period and an additional projected increase of $6.1 million in the 2005 -2006 projection. This number excludes the Storm Damage Reserve increase, which I have just discussed. By far the largest single contributor to this increase (approximately $16.5 million) relates to the cost to insure our nuclear assets. The largest driver for increased nuclear insurance costs has been a reduction in FPL's distributions from Nuclear Electric Insurance Limited (NEIL) (from a high of $26 million in 2002 to $12.9 million in 2004, a reduction of $13.1 million). We believe an increase in industry nuclear claims combined with three consecutive years of negative investment portfolio returns are the primary drivers of the reduction in distributions. NEIL has indicated that it is unlikely that distributions will return to their unusually high 2002 levels.

Non-nuclear insurance costs increased from $8.1 million in 2002 to $22.2 million in 2006, an increase of $14.1 million, with approximately $9.9 million of the increase occurring in the 2002-2004 time period, and an additional $ 4.2 million in the 2005-2006 projection.

Q. **Are increases in insurances costs occurring globally?**

A. Yes, they have in the time following September 11, 2001.

Q. **Please describe some of the drivers behind this global issue.**

A. Three primary drivers have been affecting insurance costs globally over the past several years: the impact of the events of September 11, 2001, the declining performance of insurer's investment portfolios, and payment of large losses, particularly those associated with corporate governance issues (e.g., Enron, Worldcom, Adelphia, etc.).

September 11, 2001, was the largest insured loss in history. According to the Insurance Information Institute, the estimated insured loss estimate for 9/11 was $32.5 billion. After 9/11, many parties sought to increase their insurance coverage, while concurrently the supply of insurance decreased because of the large losses. In line with the basic principles of economics, this caused premiums to increase significantly. Furthermore, coverages began to narrow, as insurance carriers created more exclusions. Companies must purchase additional insurance to cover these exclusions. A prime exclusion example is related to terrorist insurance. After 9/11, insurance companies began to exclude terrorism from their policies. The federal government stepped in and created an insurance backstop program titled the Terrorism Risk Insurance Act (TRIA). With TRIA, insured companies had to purchase terrorism insurance (or do without it) which had previously been included in general property insurance. TRIA expires on December 31, 2005 and the future of terrorism insurance remains uncertain.

The second global driver behind the significant increase in insurance premiums is the decline of many insurers' investment portfolio returns. The drop in stock market returns and large payouts for disasters in recent years, have forced insurance providers to increase premiums to compensate for their loss of capital. Some concrete explanations on the loss of capital are described below.

- Net investment income for the insurance industry has declined from its peak in 1997 of $41.5 billion to an estimated $37.7 billion in 2004.
- As of 2004, loss reserve developments for the Property and Casualty insurance industry increased more than $49 billion for policy periods 2001 to 2003.
- Standard and Poor's estimates $250-$275 billion of capacity depletion in the insurance industry from 2001-2003 due to equity/credit losses, September 11, 2001, and reserve increases.

The third driver behind the rapid increase in insurance premiums is the rapid price increases associated with directors and officers (D&O) liability insurance. According to the Risk and Insurance Management Society Inc. Benchmark Survey, D&O premiums increased by an average of 206% in the twelve month period beginning the second quarter of 2002. D&O insurance liability costs contribute the single largest portion of FPL's total projected non-nuclear insurance increase.

Q. In addition to the global drivers, has FPL had any company-specific issues which would cause the significant increase in insurance costs?

A. Yes, there are several company–specific factors. First, the amount of assets the Company has to insure has increased and will continue to increase. From 2002-2006, the Company expects the value of its insurable non-nuclear assets to increase from $9 billion to approximately $11.0 billion. Secondly, while the Company has had an excellent overall long-term loss history, FPL submitted several property loss claims in the 2002-2003 time period. Lastly, the Company had locked-in insurance rates for a multiyear period; as the lower locked-in rates began to expire, price increases were more dramatic over this 2002-2004 time period. The best example is in non-nuclear property insurance, where FPL had a fixed rate program from 1999-2002.

2007 ADJUSTMENT FOR TURKEY POINT UNIT 5

Q. **Why is FPL requesting a subsequent year adjustment in base rates in 2007 for the incremental revenue requirements for Turkey Point Unit 5?**

A. The addition of the Turkey Point 5 generating plant is a significant item with substantial operating and financing costs, the impacts of which are not reflected in FPL's projections for 2006 and will have an immediate, substantial, negative effect on FPL's earnings in 2007. Further, the Commission approved Turkey Point Unit 5 as the least cost resource option to meet the incremental needs associated with the rising demand for reliable power from our customers. Facing such a known and significant cost impact only a few months outside of the proposed test year, FPL believes that it is appropriate to consider that impact in this proceeding.

Certainly, everyone involved in this docket, including the Commission, will devote an enormous amount of resources this year in establishing new rates to be effective in 2006. By also considering in this proceeding the addition of Turkey Point Unit 5 in 2007, thereby mitigating the drop in the Company's rate of return due solely to the addition of this generating unit, we may avoid a follow-up full revenue requirements proceeding in 2007 --one that would be largely duplicative of the review for 2006.

Conducting a review of FPL's request for base rate relief associated with the addition of Turkey Point Unit 5 within this docket also would avoid the unintended consequence of economically discriminating against a low cost self-build option.

Q. Please explain further FPL's proposal for a limited scope adjustment due to the addition of Turkey Point Unit 5 in 2007.

A. The various cost factors that will impact the Company in 2006, as described by other FPL witnesses in this proceeding, are unabated in 2007. As shown by FPL's 2007 Forecast schedules and the testimony of Mr. Davis, FPL's revenue deficiency in 2007, assuming full relief is granted in 2006, will be $86 million. Of this overall 2007 deficiency, $66 million is attributable to the revenue requirements (i.e., added capital costs and O&M expenses) associated with placing Turkey Point Unit 5 into commercial operation, scheduled for June 1, 2007. In order to address the increase in 2007 revenue requirements, FPL proposes to adjust base rates effective 30 days after Turkey Point Unit 5 goes into commercial operation. FPL proposes to base the amount of the increase on the incremental revenue requirements for Turkey Point Unit 5, resulting in annualized revenue requirements of approximately $123 million.

This adjustment is a conservative proxy for the full increase in revenue requirements that FPL expects for 2007 and beyond, because it does not take into account increases in other costs of service. However, FPL is prepared to accept this understated measure of the additional rate relief in the interest of administrative efficiency, limiting the necessary regulatory review to the relatively narrow issue of Turkey Point Unit 5's revenue requirements. This will avoid burdening customers and the Commission, as well as FPL, with the time and expense of a full 2007 revenue requirements proceeding. Therefore, at this time, FPL is requesting that the Company's need for additional base rate relief in 2007 associated with the impact of Turkey Point Unit 5 be considered within the scope of the full requirements proceeding for 2006.

Q. Why should the Commission approve a subsequent year adjustment for Turkey Point Unit 5 if FPL projects that it will continue to earn a return within the range requested?

A. Assuming a base rate increase in 2006, the projected earned return on equity in 2007 is 11.5%, near the low end of the range of return of 11.3% to 12.3% requested in this proceeding. This projection includes only a portion of the annualized cost of adding Turkey Point Unit 5, as the unit is not expected to be placed in service until mid-year 2007. Consequently, there will be additional costs and a further drag on earnings in 2008. All other things equal, ROE would drop well below the bottom of the range in 2008. Had the unit been placed in service at the beginning 2007, the earned return would be below the range requested. Providing for a subsequent year increase properly compensates FPL for costs incurred and maintains the earned return at a level which should delay the need to request further rate relief.

Q. What weighted average cost of capital is used to calculate the requested adjustment?

A. FPL used the projected incremental projected cost of debt, the cost of equity requested in this proceeding, and assumed a capital structure for the incremental costs that will maintain its overall capital structure on roughly a 45% debt /55% equity basis (assuming investor capital and adjusted for off-balance sheet obligations).

Q. Why is it appropriate to use an incremental weighted average cost of capital to determine the revenue requirements associated with Turkey Point Unit 5?

A. FPL is requesting a subsequent adjustment for a specific asset, not based on the overall results of a subsequent year. The incremental weighted average cost of capital represents the best estimate of the actual costs to be incurred to finance this asset. It is also consistent with the basis upon which respondent bids were evaluated during the RFP process. Using an embedded weighted average cost of capital would understate the cost of debt to be incurred and would provide for additional equity in the capital structure to offset the off-balance sheet impact of purchased power obligations when there has been no increase in such obligations.

Q. What if 2006 embedded cost of capital were used to calculate the annualized revenue requirement for Turkey Point Unit 5?

A. The weighted average debt cost included in the 2006 embedded cost of capital does not include the cost of financing Turkey Point Unit 5. If recovery is based on this cost, FPL would not collect enough to pay the cost of debt financing and still provide a reasonable return.

Q. Please summarize your testimony.

A. FPL's overall financial position today is strong, although without the requested rate increase for 2006 and subsequent adjustment for Turkey Point Unit 5 in 2007 it will decline significantly. Our strong financial position is appropriate for the risks and circumstances we face and is beneficial to the customers.

In order to maintain an appropriate degree of financial strength and to offer investors an opportunity to earn a reasonable rate of return consistent with the the risks they assume, we are asking the Commission to approve: (1) the continuation of the 55.83% adjusted equity ratio; (2) an allowed rate of return of 12.3%, including a 50 basis point performance incentive to recognize and motivate continued superior performance; (3) a rate increase that will include sufficient allowance to enable us to increase the annual accrual to the Storm Damage Reserve from the amount of $20 million to $120 million; and (4) a subsequent year base rate increase in mid-2007 for the Turkey Point Unit 5.

These recommendations collectively would keep FPL in a strong financial position - able to protect our credit rating, attract equity investment on reasonable terms, finance future system expansion at a reasonable cost, and respond with the flexibility we need to unforeseen events. We would have an incentive that encourages us to build on the superior performance results we have achieved thus far. Finally, my recommendation on the storm fund will allow FPL to achieve and maintain a reasonable plan for responding to major storms in our service territory. In the long run, all of these things add up to delivering reliable, adequate electric service at the lowest reasonable costs to our customers.

Q. Does this conclude your direct testimony?

A. Yes.

ERRATA SHEET

(X) DIRECT TESTIMONY, OR ( ) REBUTTAL TESTIMONY (PLEASE MARK ONE WITH "X")
WITNESS: **M. P. Dewhurst**

PAGE #	LINE #	CHANGE
51	16	The range should be 11.3 to 13.3 (not 11.3 to 12.3)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF ROSEMARY MORLEY

DOCKET NO. 050045-EI

MARCH 22, 2005

Q. Please state your name and business address.

A. My name is Rosemary Morley. My business address is 9250 West Flagler Street, Miami, Florida, 33174.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company (FPL or Company) as a Rate Development Manager in the Rates & Tariffs department.

Q. Please describe your duties and responsibilities in that position.

A. I am responsible for developing electric rates at both the retail and wholesale levels. At the retail level, I am responsible for developing the appropriate rate design for all electric rates and charges. I am also responsible for proposing and administering the tariff language needed to implement those rates and charges.

Q. Please describe your educational background and professional experience.

A. I hold a bachelor's degree in economics from the University of Maryland and a master's degree in economics from Northwestern University. I am currently pursuing a doctorate in business administration from Nova Southeastern University. Since joining FPL in 1983 I have held a variety of positions in the forecasting, planning, and regulatory areas. I joined the Rates and Tariff Department in 1987 as a Senior Cost of Service Analyst and was subsequently promoted to Supervisor of Cost of Service. I have held the position of Rate Development Manager since 1996.

Q. Are you sponsoring an exhibit in this case?

A. Yes. I am sponsoring an exhibit consisting of ten documents which are attached to my direct testimony. They are as follows:

- Document No. RM-1, Summary of Sponsored MFRs and 2007 Turkey Point Unit 5 Adjustment Schedules
- Document No. RM-2, FPL's Base Rates Versus Inflation
- Document No. RM-3, Summary of Current Rate Structures
- Document No. RM-4, Cost of Service Methodology by Component
- Document No. RM-5, Trends in Relative Load Contributions
- Document No. RM-6, Resulting Parity Indices
- Document No. RM-7, Summary of Proposed Rate Structures
- Document No. RM-8, Cost of New Installations – Street Lights
- Document No. RM-9, Sample Bill Calculations
- Document No. RM-10, Impact on Base Rates

Q. Are you sponsoring or co-sponsoring any MFRs in this case?

A. Yes. The MFRs I am sponsoring or co-sponsoring are listed on Document No. RM-1.

Q. Are you sponsoring or co-sponsoring any 2007 Turkey Point Unit 5 Adjustment schedules or any of FPL's 2007 Forecast schedules in this case?

A. Yes. The 2007 Turkey Point Unit 5 Adjustment and FPL's 2007 Forecast schedules I am sponsoring or co-sponsoring are listed in Document No. RM-1.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address six general areas. First, I discuss the forecast of base revenues from the sale of electricity. Second, my testimony addresses the load research and loss factors which are inputs into the jurisdictional separation factors and cost of service study. Third, I describe the methodology supporting FPL's jurisdictional separation factors. Fourth, I discuss the cost of service study. Next, I address FPL's proposed target revenues by rate class. Lastly, I present the proposed rate design for achieving the target revenues by rate class.

Q. When did FPL last propose an increase in its retail base rates?

A. FPL has not proposed an increase in its retail base rates since Docket No. 830465-EI (the 830465-EI case) was initiated in November 1983. As a result of the 830465-EI case, FPL's base rates were increased in 1985. No increase in base rates has occurred since that time. Indeed, FPL has reduced its retail base rates three times since 1985. In January 1990, base rates were reduced by $38 million as a result of a review of the Company's earnings following a reduction in the corporate income tax rate. In April 1999, base rates were reduced by $350 million as a result of a settlement agreement.

Then in April 2002, a second settlement agreement reduced base rates by another $250 million. As a result of these reductions, FPL's current retail base rates are 16% lower than they were in 1985 while consumer prices as measured by the Consumer Price Index have increased over 80% during the same period (Document No. RM-2). In addition, both the 1999 and 2002 settlement agreements provided for annual revenue rebates to customers based on prescribed revenue thresholds. In total, the 1999 and 2002 rate agreements are estimated to result in almost $4 billion in customer savings by the end of 2005.

OVERVIEW OF BASE REVENUES AND RATE STRUCTURES

Q. Please provide an overview of adjusted jurisdictional revenues.

A. Adjusted jurisdictional revenues are incorporated into the separation factors and cost of service study. MFR C-5 outlines the various revenue components comprising adjusted jurisdictional revenues including base revenues from the sale of electricity and miscellaneous revenues. My testimony specifically addresses the development of the forecast of base revenues from the sales of electricity.

Q. What is meant by base revenues from the sale of electricity?

A. Base revenues from the sale of electricity represent FPL's billed revenues from the sale of electricity, exclusive of revenues generated from adjustment clauses.

Q. How are base revenues from the sale of electricity determined?

A. Base revenues from the sale of electricity are determined by applying the applicable tariff charges, excluding the cost recovery adjustment clause factors, to the appropriate billing determinants. As described in Document No. RM-3, FPL has more than 30 retail rate schedules, each with its own set of tariff charges and billing determinants.

Q. What is meant by billing determinants?

A. Billing determinants are the parameters used for billing customers. Billing determinants reflect the rate structure established for a given rate schedule. As such, customer, demand, and energy charges are each associated with their own set of billing determinants. Customer determinants are expressed in terms of the number of accounts billed by month. Demand determinants are expressed in terms of kilowatts (kW), while energy determinants are expressed in terms of kilowatt-hours (kWh). Some rate schedules are limited to customer and energy billing determinants. For example, customers in the small general service rate schedule (GS-1) are charged a customer charge and a cents/kWh energy charge. GS-1 customers represent the smallest of commercial/industrial electric customers, those with maximum demands below 21 kW and their rate does not include a demand charge. Larger commercial/industrial customers, on the other hand, are charged on the basis of their demand, i.e., their maximum electric usage in a given time period, and energy. Thus, the rate structure for the general service demand (GSD-1) rate schedule includes a customer charge, a cents/kWh energy charge, and a $/kW demand charge.

Q. **What are the current rate structures for the major rate schedules?**

A. Document No. RM-3 provides a narrative explanation of the current rate structures of FPL's major rate schedules.

FORECAST OF BASE REVENUES

Q. **What were the major inputs used to produce the forecast of retail base revenues from the sale of electricity for 2006?**

A. The major inputs in the process were the customer and energy (kWh) sales forecasts by revenue class produced by Dr. Green.

Q. **What is the difference between revenue classes and rate schedules?**

A. Revenue classes represent general categories of customers used for financial reporting purposes. There are six retail revenue classes: residential, commercial, industrial, street and highway lighting, railroads, and other. The railroads revenue class is the only class specific to a particular rate schedule; the Metropolitan Transit Service (MET) rate schedule and the railroads revenue class are synonymous. In all other cases, revenue classes are a combination of different rate schedules. In order to provide the level of detail required in the MFR-E Schedules, the forecasts of sales and customers by revenue class were converted into forecasts of sales and customers by rate schedule.

Q. **Please describe how the customer and sales forecasts by rate schedule were produced.**

A. First, specific sales and customer forecasts were developed for certain rate schedules. For example, the Sports Field Service (OS-2) and

Commercial/Industrial Load Control (CILC) rate schedules are closed to new customers. Therefore, the forecasted number of customers under those rate schedules is based on their June 2004 values. The kWh sales forecast for the closed rate schedules was based on the most recent actual kWh sales data escalated by the projected change in use per customer from Dr. Green's forecast by revenue class.

Second, the forecast for the number of customers and kWh sales for the remaining rate schedules was developed based on the historical relationship between customers and sales by rate schedule and customers and sales by revenue class. Historical percentages were applied to the forecast of customers and sales by revenue class. The result was a forecast of sales and customers by retail rate schedule for the year 2006.

Q. How was the forecast of sales and customers by rate schedule used to develop the retail base revenue forecast?

A. As needed, additional derivations were made to complete the forecast of customer and energy billing determinants by rate schedule. For example, the kWh sales for RS-1 were segmented to reflect the inverted rates described in Document No. RM-3. Likewise, for time-of-use rate schedules, total sales were segmented between on-peak and off-peak sales based on historical patterns. In addition, for demand-metered rate schedules, billing demands were developed based on the historical relationship between billing demand and billed sales by rate schedule.

Once all billing determinants were forecasted, the retail base revenue forecast was developed by applying the currently-approved base tariff charges to the forecasted billing determinants. The result was a monthly forecast of retail base revenue by rate schedule for the year 2006.

Q. Which MFRs provide detail on the retail base revenue forecast described above?

A. The currently-approved base tariff charges are shown on MFR A-3. MFR E-15 provides a description of how the projected billing determinants were developed. The results of applying the base tariff charges to the projected billing determinants are provided in MFR E-13c. Additional detail on the base revenue forecast for the lighting rate schedules is given in MFR E-13d.

LOAD RESEARCH AND LOSS FACTORS

Q. Has the Commission reviewed and approved the company's load research?

A. Yes. Florida Administrative Code Rule 25-6.0437 requires that investor-owned utilities serving at least 50,000 retail customers submit a load research sampling plan every three years to the Commission for review and approval. FPL's most recent sampling plan was approved in December 2002 in Docket No. 020920-EI. In addition, the rule requires that utilities submit a complete load research study every three years. FPL's most recent complete load research study was filed with the Commission in April 2004.

Q. Why is load research a necessary input into the jurisdictional separation factors and cost of service study?

A. Load research provides information on usage characteristics needed to allocate costs between customer groups. For jurisdictional separation purposes, the load research provides a basis for allocating costs between retail and wholesale customers. For a retail cost of service study, the load research provides information needed to allocate costs among the retail rate classes.

Q. Can you summarize the information provided by the load research study?

A. The load research study provides information on each rate class's contribution to the system peak (CP), as well as its class or group non-coincident peak (GNCP), and its customer non-coincident peak (NCP). The contribution to the system peak represents the rate class usage at the time of the system peak. By contrast, the class or group non-coincident peak represents a rate class's maximum demand as a class. The customer non-coincident peak demands are the sum of the individual customer peaks regardless of when they occur. Load research data on all of the above are developed on a monthly basis for each wholesale and retail rate class. The cost of service study, in turn, is performed at the retail rate class level. In total, FPL has twenty retail rate classes.

Q. Are these rate classes the same as the rate schedules discussed under the retail revenue forecast?

A. Not always. In some cases, load research combines certain rate schedules into a single rate class. Consistent with their treatment in the 830465-EI case, time-of-use rate schedules are combined with their non-time-of-use counterparts. For example, residential non-time-of-use, RS-1, and residential time-of-use, RS(T)-1 are combined together. The grouping of customers within load research is consistent with Florida Administrative Code Rule 25-6.0437.

Q. How is load research information developed by rate class?

A. Load research information by rate class is developed by sampling, modeling, or 100% metering with interval recording meters. Sampling is performed for the following rate classes: RS(T)-1, GS(T)-1, GSD(T)-1, GSLD(T)-1. FPL's sampling plan for these rate classes was approved in Docket No. 020920-EI. The Ratio Extrapolation technique was the methodology utilized to expand the historical load research data for sampled rate classes. This methodology estimates the total rate class demand by applying the ratio of demand to billed energy for each interval times the total population billed energy. The sampling results for these rate classes are filed every three years with the Commission. The most recent sampling results were filed with the Commission in April 2004.

The following retail rate classes are 100% metered with interval recording metering: CILC-1D, CILC-1G, CILC-1T, CS(T)-1, CS(T)-2, GSLD(T)-2,

GSLD(T)-3, MET, SST-1T, SST-1D1, SST-1D2, and SST-1D3. The Ratio Extrapolation technique is used for the CILC-1D, CILC-1G, CS(T)-1, GSLD(T)-2 rate classes. As needed, the Mean Per Unit Extrapolation technique was the methodology utilized to expand the historical load research data for the other census rate classes.

The usage characteristics of the lighting rate classes are modeled based on the estimated number of burn hours. According to this modeling, SL-1 and OL-1 lights are on an average of 48% of all hours in a year. On the other hand, the Traffic Lights SL-2 rate class was modeled by assuming a 100% load factor.

Prior to 2002, the Sports Field Service (OS-2) rate class was also modeled. Since that time, interval recording meters have been installed on a random sample of OS-2 accounts. The rate class's load research for 2002 and 2003 was developed by using these sample points and the previously described Ratio Extrapolation technique.

Q. **Please discuss the historical load research information included in this filing.**

A. MFR E-11 Attachments 2, 3, and 4, respectively, provide the monthly load research data for the years 2001, 2002, and 2003. The load research data for these years has been previously used in adjustment clause filings. The historical load research information provided the basis for the projected 2006 load research data shown in MFR E-11, Attachment 1.

Q. Please describe how the projected 2006 load research data were developed.

A. The historical load research data were combined with the sales forecast by rate class to develop the coincident and non-coincident demand figures for the projected test year 2006. Load research data for the years 2001 through 2003 were used. Monthly ratios of each rate class's coincident peak, non-coincident group peak, and customer non-coincident peaks to actual kWh sales were developed for each of the three years of historical load research data.

Projected 2006 monthly ratios were then developed based on the average of the three years of historical ratios. The projected ratios were then combined with the sales forecast by rate class to derive the coincident peak, non-coincident group peak, and customer non-coincident peak demands for each class. As appropriate, adjustments were made where rate class-specific factors (e.g., migration of large customers from rate classes) were significant. Adjustments were also made to account for historical load control events.

Q. Has the ratio method of developing projected load research information just described been utilized previously?

A. Yes. The forecasted load research data in FPL's MFR filings in FPSC Docket Nos. 900038-EI and 001148-EI, utilized this methodology.

Q. How was the sales forecast by load research rate class developed?

A. The sales forecast by rate schedule developed for the retail base revenue forecast was aggregated into the load research rate classes. Thus, the energy billing determinants reported in MFR E-13c are consistent with the projected load research data.

Q. Are the forecasted load research data consistent with the system load forecast?

A. Yes. The forecasted load research data are consistent with the forecast of system monthly peak demands for 2006 presented in MFR E-18 and with the forecast of system sales for 2006 presented in MFR F-8.

Q. Which MFRs provide additional information on load research?

A. MFRs E-9 and E-17 provide additional information on load research.

Q. How are the load research data used in the development of the separation factors and cost of service study?

A. The load research data are utilized in developing the allocation factors shown in MFR E-10. The load-related allocation factors are based on the load research data with adjustments for losses as needed.

Q. How are the adjustments for losses determined?

A. Dr. Green forecasts system-wide energy losses and company use. I convert these system-wide estimates into loss adjustment factors by voltage level and by rate class. MFRs E-19a, E-19b and E-19c provide the details of this process. When these loss factors are applied to the corresponding rate class voltage levels for the twelve monthly coincident peaks, the resulting value is termed the 12 CP adjusted for losses. Load data by rate class adjusted for losses is summarized in MFR E-9.

JURISDICTIONAL SEPARATION FACTORS

Q. What are separation factors?

A. Separation factors estimate the jurisdictional/non-jurisdictional division of cost responsibility between retail and wholesale customers. The separation factors are expressed as figures between zero and one with the former indicating 0% retail responsibility and the latter indicating 100% retail responsibility. Separation factors are developed at the level of detail needed for cost allocation purposes.

Q. What types of transactions are considered wholesale jurisdictional?

A. Sales of electricity at the wholesale level are considered wholesale jurisdictional. This includes requirement power sales to other utilities, which are firm, long term sales, as well as opportunity sales. Transmission service between utilities also falls under wholesale jurisdiction.

Q. What is the significance of these different types of power sales in developing separation factors?

A. The FPSC has historically made a distinction between separated versus non-separated wholesale power sales. As outlined in Docket No. 970001-EI, Order No. PSC-97-0262-FOF-EI, wholesale sales that are non-firm or less than one year in duration are treated as non-separated sales because a utility does not commit long-term capacity to such wholesale customers.

Q. What are separated wholesale sales?

A. The FPSC has historically required utilities to separate and treat as 100% wholesale jurisdictional firm sales of more than one year which commit production capacity to wholesale customers. Wholesale requirements sales meet this definition; therefore, the revenues and loads associated with these transactions are assigned a separation factor of .0000, which indicates 0% retail cost responsibility. FPL's wholesale requirement sales for the 2006 test period include the Florida Keys Electric Cooperative (FKEC) and City Electric System of Key West power sales contracts, the Metro-Dade Solid Waste Management (MDSW) contract, and the Florida Municipal Power Authority (FMPA) power sales contract.

Q. How are costs separated between wholesale and retail loads?

A. Separation factors are developed consistent with the cost methodology specified in MFR E-1. MFR E-10, Attachment 1, outlines the specific methodology used to develop the separation factors by each component of cost.

Q. How are the separation factors incorporated into the cost of service study?

A. The separation factors are used to compute the jurisdictional rate base and net operating income, which are reported on MFR B-6 and C-4 respectively. Jurisdictional rate base and net operating income, in turn, are allocated to the retail rate classes in the cost of service study.

COST OF SERVICE METHODOLOGY

Q. Please provide an overview of a cost of service study.

A. A cost of service study 1) functionalizes, 2) classifies, and 3) allocates the various components of rate base and net operating income. Functionalization refers to the assignment of costs into one (or more) of the major functions of an electric utility, e.g., production, transmission, distribution, and customer service. Classification refers to the categorization by cost driver, that is, the determination of whether a cost is driven by demand, energy, customer, or lighting-related factors, or a combination thereof. Finally, each component is allocated among the rate classes. The method of allocating a cost should be consistent with its functionalization and classification. Simply put, a cost classified as demand-related should not be allocated on the basis of kWh of energy and vice versa. On the other hand, a demand-related cost attributable to the distribution function may utilize a different allocation methodology than that utilized for a demand-related cost attributable to the production function.

Q. What role does the cost of service study play in supporting the Company's proposed changes to its retail base rates?

A. The cost of service study serves as a guide in determining the target revenues by rate class. In addition, the cost of service study is among the inputs used in determining the specific charges for each rate schedule.

Q. Please explain the treatment of production plant in FPL's cost of service methodology.

A. Consistent with Commission policy, FPL's cost of service study utilizes a 12 CP and 1/13th methodology for production plant. The 12 CP and 1/13th methodology recognizes that the decision to add generating capacity is driven by peak demands on the system. This methodology classifies 12/ 13th, or 92%, of costs on the basis of coincident peak demand and 1/13th, or

8%, of costs on the basis of energy. That portion classified on demand is allocated to the individual rate classes based on their 12 CP contributions, adjusted for losses, while the portion allocated on energy is allocated based on the kWh sales, adjusted for losses. All generating units under the 12 CP and 1/13th methodology are treated consistently, based on their function (i.e. production), their classification (92% demand and 8% energy) and their allocation (contribution to the system peak and kWh of energy).

The 12 CP and 1/13th methodology has a significant history of regulatory acceptance in Florida. Indeed, with the exception of one generating unit, the 12 CP and 1/13th methodology was approved for allocating production plant approved in the 830465-EI case.

Q. Please explain the exception to the 12 CP and 1/13th methodology approved in the 830465-EI case.

A. The previously approved methodology incorporated a special treatment for the St. Lucie #2 nuclear generating unit. In the 830465-EI case, instead of using the 12 CP and 1/13th methodology, the portion of the St. Lucie #2 unit classified on energy was based on the residual cost of the unit above that of a peaking unit. Thus, in the 830465-EI case, approximately 25% of the St. Lucie #2 unit was classified on the basis of demand, and approximately 75% of the unit was classified on the basis of energy. At that time, St. Lucie Unit 2 had only recently gone into service, and it represented a substantial percentage of FPL's total production plant in rate base. Today, St. Lucie Unit 2 has been in service for approximately 21 years, and its remaining contribution to total production plant is much smaller. The special exception made for St. Lucie Unit 2 should no longer apply, so FPL is not proposing a cost of service study reflecting the St. Lucie Unit 2 exception. Instead, a 12 CP and 1/13th methodology has been used for all production plant.

Q. How does FPL's cost of service methodology treat transmission plant?

A. With the exception of transmission pull-offs (which are required to connect transmission voltage customers to the grid), transmission plant has also been classified on the basis of 12 CP and 1/13th. That portion of transmission plant classified on demand has likewise been allocated to the individual rate classes based on their 12 CP contributions, adjusted for losses, while the portion allocated on energy is allocated based on the kWh sales, adjusted for losses. This mirrors the treatment of transmission plant approved in the 830465-EI case.

Q. How does FPL's cost of service methodology treat distribution plant?

A. Unlike production and transmission plant which serve all of FPL's retail classes, distribution plant is often specific to particular rate classes. Metering costs, for example, are not relevant to lighting classes, such as SL-1 and OL-1, which are unmetered. Likewise, the cost of secondary lines is not incurred in providing service to transmission-level customers. As a result, the distribution function is actually a mix of a number of distinct sub-functions, each with its own allocation methodology. Substations and primary voltage lines are allocated on the basis of the non-coincident group peaks of customers served from the distribution system. Secondary voltage lines are allocated on the basis of the non-coincident group peaks of customers served from secondary voltages. Transformers are allocated on the basis of the non-coincident customer peaks of customers served from secondary voltages.

Metering equipment is classified on a customer basis and is allocated on the basis of meter costs weighted by the number of metered accounts. In addition, service drops (or their equivalent) are classified on a customer basis. Thus, transmission voltage customers are allocated the cost of transmission pull-offs, primary voltage customers are allocated the cost of primary pull-offs, and secondary voltage customers are allocated the cost of service drops.

Lastly, costs specifically dedicated to lighting customers, including fixtures, poles, and conductors, are directly assigned to those rate classes. FPL's methodology for treating distribution plant just described is consistent with that approved in the 830465-EI case.

Q. **Is additional detail available outlining the methodology used in the cost of service study?**

A. Yes. Document No. RM–4 provides detail on the methodology used in the cost of service study. This document is intended to provide additional detail on MFR E-10, Attachment 1, which discusses the cost methodology utilized in the separation factors and cost of service study. Document No. RM-4 provides the cost of service treatment for each component of rate base and net operating income.

Q. Which MFRs outline the functionalization, classification and allocation of costs in the cost of service study?

A. MFRs E-4a and E-4b show the classification and functionalization by FERC account of rate base and expenses respectively. MFRs E-3a and E-3b show the allocation of rate base and expenses by FERC account to the individual rate classes.

COST OF SERVICE RESULTS

Q. What results are produced in the cost of service study?

A. The cost of service study produces a calculation of rates of return (ROR) by rate class. RORs are based on net operating income divided by rate base. The system average ROR represents the jurisdictional adjusted net operating income divided by the jurisdictional adjusted rate base. Having allocated the various components of jurisdictional adjusted rate base and jurisdictional adjusted net operating income across the retail rate classes, RORs can then be computed on a rate class level. RORs on a system and rate class level are reported in MFR E-1.

Q. How are comparisons in ROR by rate class made?

A. A measure of how a rate class's ROR compares to the system average can be computed by dividing the class ROR by the system ROR. The resulting figure is referred to as the parity index. Thus, a rate class with a parity index of 100% would be earning the same ROR as the system average. A rate class with a parity index less than 100% would be earning an ROR less than the system average ROR, while the opposite would be true for a rate class with an index above 100%. A rate class with a parity index of 100% is said to be at parity, a state which implies that the rate class ROR is consistent with the system average ROR.

Q. **What does FPL's cost of service study show regarding the system average ROR and the parity indices by rate class?**

A. FPL's cost of service shows a system average earned ROR of 6.31% for the 2006 test year. This is consistent with the retail ROR reported in MFR A-1. The cost of service study indicates that the parity indices vary by rate class with some class indices well above 100% and others well below 100%.

Q. **Are there any specific trends in cost or load characteristics which may have had an impact on the parity indices by rate class?**

A. As shown in Document No. RM-5, there has been a decline in the contribution to system peak attributable to the residential rate class, RS-1, in comparison with the rate class' increasing share of total kWh of energy since the 830465-EI case. All things held equal, this trend suggests declines in the RS-1 share of demand-related costs, increases in the RS-1 share of energy-related costs, and increases in the RS-1 share of base revenues, which for the most part are a function of kWh of energy. On balance, the trend is consistent with increases in the RS-1 parity index.

By contrast, the Large General Service Demand rate class, GSLD-1, has experienced relatively faster increases in its contribution to the peak than in its share of total kWh of energy since the 830465-EI case. This suggests that the GSLD-1 rate class is accounting for an increasing share of demand-related costs. This trend is also consistent with the decline in the GSLD-1 parity index evident since the 830465-EI case.

Q. Are there other specific factors contributing to the disparities in rates of return?

A. Yes. The implementation of the 1999 reduction in base rates resulted in higher percentage reductions in base revenues for the larger commercial/industrial rate classes. In addition, FPL's current rate classes in some cases consist of a very limited number of customers. For example, four retail rate classes for which FPL has estimated an ROR have fewer than ten customers forecasted for test year 2006, while seven have fewer than twenty. Customer migration and individual variations in load usage can be expected to have a larger impact on those rate classes with a limited number of customers.

Q. What other results are produced in a cost of service study?

A. A cost of service study also calculates revenue requirements by rate class. Revenue requirements consist of a return on rate base plus income taxes and expenses. Thus, revenue requirements represent the level of revenues required to earn a particular ROR. In this filing, three sets of revenue requirements by rate class have been developed. One set of revenue requirements, shown in MFR E-6a, incorporates each rate class's individual or class ROR. The second set of revenue requirements, also presented in MFR E-6a, is based on the system average earned ROR. The third set of revenue requirements, shown in MFR E-6b, is based on the required average system ROR. The revenue requirements based on the required system ROR represents the cost which would be recovered, if all rate classes had a parity index of 100% and if FPL were earning the required ROR supported in MFR A-1. Revenue requirements when divided by the appropriate billing determinants are referred to as unit costs. Thus, the cost of service provides estimates of the demand, energy and customer unit costs of each rate class. The revenue requirements and unit costs at the required ROR serve as a guide in designing rates.

TARGET REVENUES BY RATE CLASS

Q. What is meant by the target revenues by rate class?

A. The target revenues by rate class represent FPL's proposed level of revenues by rate class designed, in total, to achieve the required ROR for the test year presented in MFR A-1.

Q. How are target revenues by rate class determined?

A. In a rate case proceeding in which an adjustment in rates is proposed, the cost of service serves as a guide in evaluating any proposed changes in the level of revenues by rate class. More specifically, the allocation of any revenue increase should be assessed in terms of its impact on the parity between rate classes.

Q. Has the FPSC recognized other factors in evaluating the target revenues by rate class besides the cost of service?

A. Yes. In past circumstances, the FPSC has found it appropriate to use a rule-of-thumb that limits increases to individual rate classes to no more than

150% of the system average increase and to restrict any rate class from receiving a decrease.

Q. Is FPL offering any proposals to improve parity at this time?

A. Yes. FPL proposes to move all rate classes closer to parity. Specifically, FPL proposes using +/- 10% of parity as a goal in determining the target revenues by rate class. In other words, if a rate class is earning in excess of 110% of parity the goal is to move that class to a parity index of no more than 110%. Conversely, if a rate class is earning less than 90% of parity the goal is the move that class to a parity index of at least 90%. In addition, no rate class would receive a decrease under our proposal.

Q. Why isn't FPL proposing to limit rate increases to 150% of the average increase?

A. If a utility has been involved in a rate proceeding every few years, then significant progress toward parity may be achievable even while limiting rate increases to 150% of the system average. In FPL's case, however, limiting rate increases to 150% of the system average increase would allow what are, in some cases, extreme subsidies among rate classes to continue. Document No. RM-6 outlines the disparities among rate classes which would be tolerated if rate increases were limited to 150% of the system average. Overall, limiting rate increases to 150% of the system average would result in only six out of twenty rate classes having a parity index within +/- 10% of parity.

Q. **Does FPL's approach to parity recognize any factors other than the cost of service in determining target revenues by rate class?**

A. Yes. The objective of achieving +/- 10% of parity for all rate classes is tempered in two respects. First, there are some rate classes that are earning below the system average return to such an extreme extent that moving them to within +/- 10% of parity would require base rate increases in excess of 50%. This is the case with FPL's OL-1 rate class which has a parity index of -21%. FPL is proposing to limit the base revenue increase to any rate class to 25% or less. The rate classes affected by this proposed cap are OL-1, OS-2, SL-1 and SST1-D.

Second, in the case of distribution voltage demand metered commercial/industrial customers, the +/- 10% guideline is applied to a group of rate classes rather than to an individual rate class due to the potential for migration among classes. Commercial/industrial customers may migrate among the GSD and GSLD rate classes (or between the CS-1 and CS-2 rate classes) depending on their maximum kW during any twelve month period. Moreover, the GSD, GSLD and CS rate classes have historically shared a very similar rate structure. In light of this, a level of target revenues has been established for distribution voltage demand metered commercial/industrial customers as a group. At the same time, FPL's proposed target revenues result in significant improvements in the parities of each of the distribution voltage demand metered commercial/industrial rate classes.

Q. What impact would FPL's target revenues by rate class have on parity?

A. As shown in Document No. RM-6, under FPL's proposed target revenues by rate class the parity of all rate classes is improved. In addition under FPL's proposal, the number of rate classes within +/- 10% of parity is increased from 3 to 11.

Q. How does FPL propose to achieve these target revenues by rate class?

A. FPL proposes to use a three-prong approach that includes: 1) changes to existing rates, 2) the addition of three new optional rates, and 3) revisions to service charges. In the remainder of my testimony, I will outline each element of FPL's proposal in detail.

PROPOSED CHANGES TO EXISTING RATES

Q. Please explain why FPL is proposing changes to its existing rates.

A. FPL is proposing to change its existing rates in order to support the target revenues by rate class outlined above. The changes to existing rates outlined below are consistent with the objectives of providing rates that are cost-based and understandable, and that send appropriate price signals to customers.

Q. Please describe in general terms the methodology you used in developing the proposed changes to FPL's existing rates.

A. Generally speaking, the inputs I relied on include the target revenues by rate class presented in MFR E-8, the unit costs at the required ROR presented in MFR E-6b, and the projected revenues and billing determinants by rate schedule presented in MFR E-13c. As appropriate, I have used the unit costs in MFR E-6b as a starting point and then made adjustments to achieve the target revenue by rate class outlined above. In addition, I have adjusted every rate class's base rates to remove the embedded gross receipts tax.

Q. **Please explain the adjustment to remove the embedded gross receipts tax.**

A. This adjustment is being made to make FPL's rates more understandable. FPL is the only electric investor-owned utility (IOU) in Florida that has not increased base rates since the gross receipts tax was increased in 1992. Consequently, FPL is the only electric IOU with a portion of its gross receipts tax embedded in base rates and the remaining portion shown as a line item on the customer's electric bill. This is a frequent source of confusion in explaining the rates to customers.

Q. **Do the jurisdictional adjusted revenues incorporated into the separation study and cost of service study reflect the removal of the gross receipts tax embedded in base rates?**

A. Yes. The gross receipts tax embedded in base rates has been removed from the jurisdictional adjusted base revenues.

Q. **What specific details are available outlining how other changes FPL is proposing to its existing rates were developed?**

A. Attachment No. 2 of MFR E-14 provides workpapers outlining the derivation of the proposed changes to FPL's existing rates. In addition, Document No. RM-7 provides a narrative explanation of the proposed rate structures, much the same way as Document No. RM-3 outlines the current rate structures.

Q. What are the most significant revisions FPL is proposing to its current rate structures?

A. In terms of the major rate schedules, FPL is proposing to restructure its residential rate RS-1 and its demand-metered commercial/industrial rate schedules.

Q. How is FPL proposing to change its residential rate schedule, RS-1?

A. FPL is proposing to raise the inversion point on the RS-1 rate from 750 kWh to 1,000 kWh. This change is appropriate given the increase in use per customer that has taken place since the 750 kWh inversion point was established in 1977. In raising the inversion point, an energy charge of 3. 481 cents is proposed for the first 1000 kWh and an energy charge of 4. 481 cents is proposed for all additional kWh. The one cent delta between the energy charges is consistent with the delta which existed in FPL's RS-1 rate schedule prior to the 2002 rate settlement agreement. The proposed customer charge of $7.00 approximates the customer unit cost presented in MFR E-6b.

Q. How is FPL proposing to change its demand-metered rates for commercial/industrial customers?

A. Currently, GSD-1, GSLD-1, GSLD-2, CS-1 and CS-2 all share the same base demand charge while the energy charges for these classes vary inversely with the class's kW threshold. This rate structure was approved in the 830465-EI case. In that case, the Commission found it appropriate to set the demand charges for the GSD-1, GSLD-1, GSLD-2, CS-1, and CS-2 classes at the same level rather than vary those charges with each class's demand unit cost. Moreover, the standard demand charge approved by the Commission was generally below the classes' demand unit costs. Consequently, the energy charges approved for these schedules were designed to recover any demand costs not recovered through the demand charge. The Commission's decision in approving this rate structure relied, in part, on the fact that the coincident peak contributions of these classes tends to be more highly correlated with their kWh sales than with their billing kW. Thus, the recovery of a portion of demand costs through the energy charges was deemed appropriate.

The cost of service study in this filing suggests that there is little basis for charging GSD-1, GSLD-1, GSLD-2, CS-1 and CS-2 customers the same demand charge while charging a lower energy charge based on the rate schedule's kW threshold. In light of this, and with the objective of simplifying the rates where appropriate, a single set of energy and demand charges is proposed for GSD-1, GSLD-1, GSLD-2, CS-1 and CS-2. In addition, the 10 kW exemption for GSD-1 customers would be eliminated under FPL's proposal. FPL is the only electric IOU in Florida that grants customers a kW exemption in its demand-metered rates. In the 830465 case, the Commission acknowledged the goal of eliminating the exemption. Lastly, the customer charges proposed for these classes approximate the class's customer unit costs presented in MFR E-6b with adjustments for their earned rates of return.

Q. How is FPL proposing to change its lighting rate classes?

A. FPL's current lighting rate classes include SL-1, OL-1 and SL-2. Excluding SL-2, these rates are substantially below parity. Thus, the 25% cap on the proposed revenue increase applies to SL-1 and OL-1.

Q. How does FPL propose to recover its target revenue from the lighting rate classes?

A. Document No. RM-8 provides the estimated cost of installing and maintaining new street lighting fixtures, poles and conductors. These figures suggest that the cost of installing and maintaining new poles and conductors substantially exceeds their charges under the current tariff. Accordingly, the target revenue increases for SL-1 and OL-1 are achieved primarily through increases in the pole and conductor charges with other adjustments as needed to achieve the classes' target revenues. In addition, the base energy charges for SL-1 and OL-1 are based on the energy unit cost in MFR E-6b.

Q. Which MFRs provide additional information on the proposed changes to existing rates you have outlined?

A. The impact the proposed rate changes would have on typical bills is presented in MFR A-2. MFR A-3 provides a summary of the proposed rate changes. The applicable proposed tariff sheets are presented in Attachment No. 1 of MFR E-14. The revenue impact from the proposed changes to existing rates is taken into account in calculating the revenues shown in MFR E-12, E-13a, E-13c, and E-13d and the parity indices under proposed rates are shown in MFR E-8.

NEW OPTIONAL RATES

Q. Is FPL proposing new optional rates for its commercial/industrial customers in this filing?

A. Yes. FPL is offering three new rate options to help commercial/industrial customers manage their electric bills. Two new offerings are time-of-use (TOU) rates. They are the High Load Factor TOU rate and the Seasonal Demand TOU rider. While many commercial/industrial customers have elected to take advantage of FPL's existing TOU offerings, the High Load Factor TOU rate and Seasonal Demand TOU rider will provide expanded opportunities for customers seeking a time-of-use alternative. The third new offering is an optional rate for small commercial customers with relatively constant electric usage.

Q. Please describe the optional High Load Factor TOU rate.

A. FPL's objective in offering the optional High Load Factor TOU rate is to provide a rate that is attractive to higher load factor customers while also providing a time-differentiated price signal. The optional High Load Factor TOU rate will be available to commercial/industrial customers with at least 21 kW of billing demand. Likely participants include manufacturers, grocery stores and hospitals. The standard time-of-use hours will apply under this rate.

The optional High Load Factor rate is cost-based. Distribution demand-related costs are recovered through a maximum charge equivalent to ½ of the unit cost for distribution plant. To adequately recover production and transmission demand-related costs, the on-peak demand charge includes the on-peak unit cost for production and transmission plant along with ½ of the on-peak unit cost for demand-related distribution plant. Both demand charges are based on the average combined unit costs of rate classes GSD(T)-1, GSLD(T)-1 and GSLD(T)-2. The off-peak energy charge is set at the average system energy component from the cost of service study. Derivation of the on-peak energy charge is the result of a break even calculation with the otherwise applicable rate with a 70% load factor. As a result, the demand charges under the optional High Load Factor TOU rates are higher than those under the otherwise applicable TOU rates while the energy charges are lower. Thus, only customers with a relatively high load factor are likely to elect the optional High Load Factor TOU rate.

Q. Please explain the optional Seasonal Demand TOU rider.

A. FPL's objective in offering the optional Seasonal Demand TOU rider is to provide a time-differentiated rate with a narrower on-peak window than that specified under the standard TOU rates. The optional Seasonal Demand TOU rider will be available to commercial/industrial customers with at least 21 kW of billing demand. Customers who typically experience lower usage during the summer months are likely to take advantage of the optional Seasonal Demand TOU rider. Likely participants include customers involved in the agricultural and educational sectors.

Under the standard TOU rates, an eight to nine hour on-peak window is in effect year round. Many customers interested in a time-differentiated rate may not be able to plan around such a large on-peak window year round. As an alternative, the on-peak period under the optional Seasonal Demand TOU rider is limited to 3PM-6PM weekdays (excluding holidays) in June through September. Customers under the optional Seasonal Demand TOU rider may elect to receive service under either a time differentiated or non-time differentiated rate during January through May and October through December.

The optional Seasonal Demand TOU rider is designed to reflect FPL's cost of service study. Within the cost of service study, each rate class is allocated production and transmission demand costs based on their contribution to the peak. In this allocation all twelve months of coincident peak contributions are considered. At the same time, the relative contributions to the peak from a rate class tend to vary based on its monthly coincident factors. As shown in MFR E-11, the highest coincident factors for commercial/industrial customers frequently occur during the summer months. Reflecting this, the demand charge under the optional Seasonal Demand TOU rider is higher in the summer months than it is in other months of the year. During the 3PM-6PM on-peak period a demand charge of $6.40 is proposed based on the higher coincidence factor commercial/industrial customers typically experience in June through September. Likewise, a demand charge of $5.51 is proposed during all other months in order to make the optional Seasonal Demand TOU rider revenue-neutral with the otherwise applicable commercial/industrial rate.

Q. What is the third optional rate FPL is proposing?

A. FPL is proposing the General Service Constant Use rate for small commercial customers with a relatively constant, high load factor usage which sets them apart from other GS-1 customers. Customers within the telecommunications and cable television industries are among those that might qualify for this optional rate. Consistent with an assumption of constant electric usage, the energy charge under this rate is derived from the demand and energy unit costs under the traffic signal rate class, SL-2. To help ensure that application of the rate is limited to customers with the intended load characteristics, energy charges will be assessed on the basis of a ratcheted kWh. Specifically, a customer's monthly billed kWh will be based on their maximum kWh per service day over the last 23 months.

Q. Has FPL taken into account the customer migration likely to occur as a result of the optional High Load Factor TOU rate, optional Seasonal Demand TOU rider, and General Service Constant Use rate?

A. Yes. The customer migration anticipated under these rates is presented in MFR E-13c. Only customers who would save relative to the otherwise applicable proposed rate schedule are projected to migrate to one of the optional rates. The revenue impact from this migration is taken into account in calculating the revenues under proposed rates shown in MFR E-13c and the ROR under proposed rates are shown in MFR E-8.

Q. Has FPL developed tariff sheets for its proposed optional rates?

A. Yes. The tariff sheets applicable to the optional High Load Factor TOU rate, the optional Seasonal Demand TOU rider and the General Service

Constant Use rate are presented in Attachment No. 1 of MFR E-14. The same attachment also provides the tariff sheets for FPL's existing rate schedules which are proposed to be revised as a result of this filing.

Q. How will taking service under one of these optional rates affect a customer's electric bill?

A. Because they are optional rates, it is unlikely that a customer will elect either the optional High Load Factor TOU rate, the optional Seasonal Demand TOU rider, or the General Service Constant Use rate unless it is in their benefit to do so. While individual circumstances may vary significantly from customer to customer, I provide illustrative bill calculations for each of these three optional rates in Document No. RM-9.

Q. Are there any other tariff modifications FPL is proposing?

A. Yes. FPL is proposing to close its current Premium Lighting rate schedule, PL-1, and replace it with a Decorative Lighting rate schedule, SL-3. The charges under the SL-3 rate schedule will be identical to those offered under the current PL-1 rate schedule with two exceptions. Under the current PL-1 rate schedule, customers have the option of paying for facilities in a lump-sum, over ten years, or over 20 years. The vast majority of customers have elected the 20 year option. Accordingly, the lump-sum and ten-year payment options are eliminated under the SL-3 rate schedule. Second, under the PL-1 rate schedule, facilities charges are based on work order estimates. In order to streamline the process, facilities charges under the SL-3 rate schedule will be based on generic project cost estimates. This will reduce the time and resources required to administer this rate schedule.

In addition, FPL is proposing to close the Wireless Internet Electric Service (WIES-1) Rate to new delivery points effective January 1, 2006. As stated in tariff sheet 8.120, FPL may petition to withdraw this rate schedule and transfer any existing customers to the otherwise applicable rate schedule if the total energy usage under this rates schedule has not reached 360,000 kWh by June 30, 2004. There are presently only 18,240 kWh served under this rate schedule. Accordingly, FPL is proposing to close the WIES-1 rate schedule effective January 1, 2006 and to transfer existing customers to other rate schedules by January 1, 2007. In lieu of the WIES-1 rate schedule, the unmetered GS-1 rate and General Service Constant Use rate will be available. Both the unmetered GS-1 rate and General Service Constant Use rate offer significant savings relative to the otherwise applicable standard rate.

SERVICE CHARGES

Q. What types of miscellaneous services are provided under FPL's tariff?

A. FPL's tariff outlines specific charges for initial connects on new premises, connects/disconnects on existing premises, reconnects after non-payment, and field collections on past due accounts. The tariff additionally provides for late payment fees and returned check charges. Charges for the reimbursement of unauthorized or fraudulent use of electricity and temporary construction accounts are also included in the tariff.

Q. Has FPL performed a cost study estimating the cost of providing miscellaneous services?

A. Yes. As co-sponsored by Mrs. Santos and Ms. Williams, MFR E-7 provides estimates on the current cost of initial connects on new premises, connects/disconnects on existing premises, reconnects after non-payment, and field collections on past due accounts. In many cases, the current cost of providing a service exceeds its currently-approved tariff charge.

Q. Is FPL proposing to adjust the level of these service charges?

A. Yes. FPL is proposing to adjust the charges for initial connects on new premises, connects/disconnects on existing premises, reconnects after non-payment, and field collections on past due accounts to reflect the cost of performing these transactions.

Q. Is FPL proposing any other changes to its service charges?

A. Yes. FPL is proposing to modify its returned payment charge to reflect the governing Florida Statutes. FPL currently charges $23.24 per returned payment. Section 68.065, Florida Statutes, however, specifies a tiered fee structure based on the returned payment amount. Consistent with Section 68.065, FPL's proposed return payment charge is as follows:

$25 if the payment amount does not exceed $50

$30 if the payment amount exceeds $50 but does not exceed $300

$40 if the payment amount exceeds $300 or 5% of the payment amount, whichever is greater

In addition, FPL is proposing to add a $5 minimum payment under the late payment charge. As described in MFR E-7, this late payment minimum is similar to those already approved for certain electric utilities in Florida and for gas and water utilities.

Q. Has the revenue impact from adjusting service charges been taken into account in calculating the revenue increase needed to meet the target revenues by rate class for the test year?

A. Yes. As show in MFR E-8 the increase in service charge revenues is taken into account in calculating the revenue increase needed to meet the target revenue by rate class. In effect, the increase in service charge revenues helps offset the needed increase in revenues from the sale of electricity proposed for each rate class.

2007 TURKEY POINT UNIT 5 ADJUSTMENT

Q. How is FPL proposing to recover the costs associated with Turkey Point Unit 5?

A. FPL is seeking an adjustment to reflect the annualized costs associated with Turkey Point Unit 5 which is scheduled to be placed into service in June 2007. Schedule A-1, which is sponsored by Mr. Davis, shows the proposed 2007 annualized revenue increase to recover these costs. Schedule E-13a shows the recovery of the proposed annualized revenue increase by rate class.

Q. How will FPL recover the proposed 2007 revenue increase from its customers?

A. The costs associated with Turkey Point Unit 5 are jurisdictionalized in Schedules B-6 and C-4 consistent with the previously described separation factor methodology. As shown in Schedule E-14 the jurisdictional cost associated with the Turkey Point Unit 5 was allocated to the retail rate classes by individual cost components. The allocation of each cost component was consistent with the methodology outlined in MFR E-10. Each rate class's allocated costs was then divided by its test year kWh sales. The base rate increase for Turkey Point Unit 5 was then derived by adjusting each rate class's cents per kWh factor for the estimated increase in retail kWh sales in 2007. The recovery of these costs on an energy basis is consistent with the recovery of 1985 costs approved in the 830465-EI case.

Q. **What other schedules are you sponsoring that provide additional information on the 2007 Turkey Point Unit 5 adjustment?**

A. The tariff sheets outlining the proposed 2007 rates are presented in Schedule E-14 along with the associated rate calculations. Typical bill calculations with the proposed 2007 increase are provided in Schedule A-2. Schedule A-3 summarizes the rates proposed for 2007.

Q. **Please describe these schedules.**

A The revenue increase associated with the costs for Turkey Point Unit 5 as allocated to the rate classes in Schedule E-14, Attachment No. 2 is used to determine an adjustment to each rate class' base energy charge(s). The Schedule A-2 applies the proposed charges against typical usage characteristics and provides the increase for such typical usage characteristics. Schedule A-3 provides a summary of the charges affected by the Turkey Point Unit 5 Adjustment. The proposed tariff sheets for each rate schedule incorporating the adjustment for Turkey Point Unit 5 are shown in Schedule E-14, Attachment No. 1.

Q. When would the tariffs become effective?

A FPL proposes to implement the tariffs 30 days after Turkey Point Unit 5's commercial in-service date. This proposed implementation date will ensure that the new rates are not billed for consumption taken before Turkey Point Unit 5's commercial in-service date.

Q. How will the proposed tariff implementation date affect the recovery of the cost of Turkey Point Unit 5?

A Until the plant is placed in commercial service, it continues to accrue AFUDC. However, upon placement into commercial service, the accruals cease. Since the application of the new tariff will not be applied to meter readings until 30 days after this date, coupled with the cycle billing process, FPL will underrecover costs otherwise charged as AFUDC. FPL proposes to recover the resulting underrecovered dollar amount through the fuel recovery clause by including that amount as part of the fuel cost for the true-up calculations in a future fuel clause proceeding. This proposal is consistent with the Commission's decision in Order 12348 in Docket No. 820097-EU.

CONCLUSIONS

Q. What impact will FPL's rate proposal have on the major rate classes?

A. MFR E-8 summarizes the proposed base revenue changes by rate class for the 2006 test year. In the case of RS-1, the total change in base revenues, including revenues from electric service, unbilled revenues and service charges, is approximately 8.8% of current base revenues and 4% of total revenues including adjustment factors. For commercial/industrial customers in the GSD-1, GSLD-1, GSLD-2, CS-1 and CS-2 rate classes, the total change in base revenue is approximately 14.2% of current base revenue and 5.1% of total revenues. Other rate classes will see varying increases depending on the rate of return (parity) for their respective rate classes although in no case is the increase greater than 25% of a class's current base revenues.

In addition, MFR A-2 presents the typical bill impacts for 2006 and 2007 for the major rate schedules. The typical bill calculations in this MFR are based on the changes to base rates and certain clause factors that include the effects of Company proposed adjustments. Specifically, the transfer of certain capacity costs and revenues from base rates to the Capacity Clause and the transfer of incremental security costs from the Capacity Clause to base rates are taken into account in MFR A-2. For a 1,000 kWh RS-1 customer, the typical bill increases 3.0% in 2006. For large commercial customers, such as those served under the GSLD-1 or GSLD-2 schedules, the increase for 2006 ranges between 6-8% depending on the customer's load characteristics. In 2007 the 1,000 kWh RS-1 bill increases an additional 1.3% while large commercial customers would see incremental increases of 1-1.4%.

Q. If the requested base rate relief is granted, how will FPL's base rates compare to previous levels?

A. A typical 1,000 kWh residential base bill will be $41.81 in 2006. Even with the requested increases, however, FPL's base rates would remain lower than they were in January 1999, prior to the first of two significant base rate reductions, and lower than they were in 1985, the last time FPL's base rates were increased. This is illustrated in Document No. RM-10.

Q. Please summarize your testimony.

A. I have provided background on FPL's current rate structures and forecasted retail base revenues. I have also described the load research data which is one of the inputs into the separation factors and cost of service study. In addition, my testimony explains and supports FPL's cost of service study. The cost of service study indicates the RS-1 and GS-1 rate classes are above parity while some of the larger commercial/industrial rate classes, particularly GSLD-1 and GSLD-2, are below parity. Relatively larger rate increases are needed for those rate classes currently below parity. I have outlined a proposal that improves the parity of all rate classes. Many rate classes are moved to within +/-10% of parity while no rate class receives an increase of more than 25%.

This filing represents the first time in over 20 years that FPL has sought an increase in base rates. Because base rate cases have traditionally been used as vehicles for improving the parity among rate classes, this filing represents a significant opportunity to address the parity issue. FPL has proposed revenues by rate class which would substantially improve the parity of all rate classes. A comprehensive rate restructuring has also been proposed that expands the number of rate options available to customers while better aligning the charges under FPL's existing rates with their true costs.

In conclusion, the Commission should approve FPL's rate proposals presented in my testimony because they are reasonable, cost-based and send the appropriate price signals to customers.

Q. **Does this conclude your direct testimony?**

A. Yes.

ERRATA SHEET

(x) DIRECT TESTIMONY, OR ( ) REBUTTAL TESTIMONY (PLEASE MARK ONE WITH "X")
WITNESS: **Rosemary Morley**

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STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, RPR, CRR, Official Commission Reporter, do hereby certify that the foregoing prefiled testimony was assembled under my direct supervision.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorneys or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 24TH DAY OF AUGUST, 2005.

Linda Boles

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