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

REBUTTAL TESTIMONY OF STEVEN P. HARRIS

DOCKET NOS. 050045-EI, 051088-EI

JULY 28, 2005

Q. Please state your name and business address.

A. My name is Steven P. Harris. My business address is ABSG Consulting, Inc. (ABS Consulting), 1111 Broadway Street, Oakland, California 94607.

Q. Did you previously submit direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to portions of the testimony submitted on behalf of the Florida Office of Public Counsel (OPC) by Patricia W. Merchant, the Commercial Group by James Selecky, AARP by Stephen Stewart, the Florida Retail Federation (FRF) by Sheree Brown and South Florida Hospital and Health Care Association (SFHHA) by Lane Kollen, addressing the estimated annual storm loss on Florida Power & Light Company's (FPL's) system and the witnesses' respective calculations of a proposed annual Storm Damage Accrual amount.

Q. Are you sponsoring an exhibit to your rebuttal testimony?

A. Yes. I am sponsoring an exhibit consisting of two documents, SPH-3, Storm Reserve Fund Analysis Case Results, and SPH-4, Comparison of Protection

Afforded by $120 million, $70 million and $40 million Annual Accrual, which is attached to my rebuttal testimony.

THE ABS CONSULTING LOSS ANALYSIS IS RELIABLE

Q. Do you agree with witnesses Merchant, Stewart, Brown and Selecky who suggest that a more reliable estimate of annual storm damage would be based on actual 1990 to 2004 data, or some shorter period, excluding the years 1992 and 2004 as extraordinary?

A. No. Calculating an actual or simulated expected annual storm damage amount that selectively excludes any possible damage events, whether large and infrequent or small and frequent, is neither meaningful nor appropriate. Any reliable estimate of the expected annual windstorm damage to which FPL is exposed (expected annual damage) must include the most complete and full damage distribution that can be determined both from actual experience and from simulated possible damage.

It is true that not all years will experience damage equal to or greater than any estimate of the expected annual damage. Many years may experience no damage and others greater damage. Therefore, in developing expected annual damage estimates, the most reliable methodology is to utilize the longest, most complete historical record available. Since Florida's recorded hurricane history is just over 100 years old, insurers rely on simulation modeling to extend this "known" history into thousands of simulated years for the purpose of estimating likely damage. The simulated expected annual damage to FPL's system is the best estimate of the annual damage considering all possible future hurricanes; not just the "normal" damage as proposed by Ms. Merchant, Ms. Brown, Mr. Stewart and Mr. Selecky.

Q. **Do experts agree with you that selectively excluding large events from the calculation of an expected annual damage estimate produces biased results?**

A. Yes. The Florida Commission on Hurricane Loss Projection Methodology (FCHLPM), an independent panel of experts that evaluates computer models and actuarial methodologies for projecting hurricane losses, goes to great lengths to ensure that all models used in the State for insurance rating purposes appropriately capture the full range of the hurricane hazard. As mentioned in my direct testimony, the ABS Consulting USWIND™ model used to calculate FPL's expected annual damage is one of only four models evaluated and determined acceptable by the FCHLPM for projecting hurricane loss costs.

Q. **Witnesses Merchant, Stewart, Brown and Selecky argue that FPL's annual storm damage accrual does not need to be increased substantially, if at all, because the accrual has been sufficient to cover actual storm damages incurred until the Storm Reserve balance became negative in 2004. Do you agree?**

A. No. First, remember that prior to 1993, FPL had insurance to cover storm damage to FPL's transmission and distribution assets. After Hurricane

Andrew, insurers essentially withdrew from the market and adequate amounts of transmission and distribution insurance at reasonable prices became unavailable. The situation worsened after the events of September 11, 2001. Since Hurricane Andrew, FPL has relied heavily on its Storm Reserve to self-insure for storm damage to its transmission and distribution and other assets, using annual contributions to the Reserve and earnings on the Reserve to accumulate a fund to pay for storm damage when it occurs. Mr. Dewhurst addresses the regulatory framework associated with FPL's Storm Reserve in detail.

The reason that FPL's annual accrual appears to have been sufficient between 1993 and 2003 (excluding the real and large losses of Hurricane Andrew and the hurricanes of 2004) was FPL's favorable storm history: several small storms with few moderate annual losses. There were no hurricanes with strong SSI 2 to SSI 4 winds that made direct landfalls in FPL's service territory during this period.

The intervenors' suggestions would only be acceptable if FPL's management and the Commission are willing to speculate that FPL's recent good luck over a brief, selective storm period considered by Ms. Merchant and other witnesses will continue. However, over the 100-year history, there have been many more hurricane landfalls and damaging events than in the last 13 years. Also, there is a growing body of evidence suggesting that the North Atlantic

Oscillation (NAO) and the El Niño or Southern Oscillation (ENSO) are important climate variables in modulating hurricane return periods. The damage estimated in the current ABS Consulting study, assumes the average hurricane activity over the century. If you accept the opinion that changes in the ENSO and NAO variables indicate we have entered a more active period for hurricane formation like the 1920s and 1940s, FPL may expect to experience higher than average damage to T&D over the next several years and the ABS Consulting damage estimates could understate the actual risk going forward.

Q. Please respond to Ms. Merchant's suggestion on page 9 of her direct testimony that the USWIND™ model cannot be relied upon because the model "does not distinguish between the annual damages that are less costly and those that are extraordinary."

A. Ms. Merchant is incorrect. Table 5-2 of the Storm Loss Analysis titled "Aggregate Damage Exceedance Probabilities and Expected Annual Damage by Layer," Document SPH-1, page 21 of 29, filed with my direct testimony, provides a detailed quantification of both the likelihood and severity of a full range of possible FPL storm losses. Table 5-2 shows the likelihood of damage to FPL's system exceeding a specified value over a one-year, three-year and five-year period. For example, the probability of storm damage exceeding $950 million in a single year, like the 2004 hurricane season, is 1.2%, or about a 1 in 100 year event. The likelihood of storm damage exceeding $200 million in a single year is 10.2%, or about a 1 in 10 year event. As discussed in Section 5.3 of the Storm Loss Analysis, the results of this annual damage probability analysis are inputs to the Storm Reserve Solvency Analysis.

THE ANNUAL ACCRUAL LEVELS SUGGESTED BY THE INTERVENORS PRESENT A MUCH GREATER LIKELIHOOD OF INSOLVENCY OVER THE FIVE-YEAR PERIOD

Q. Have the intervenors considered the performance of the Storm Reserve at their respective recommended annual accrual levels?

A. No. With the exception of Mr. Kollen, none of the intervenors considered the impact of their recommendations on the solvency of the Storm Reserve. Mr. Kollen believes that the balance of the Storm Reserve should be zero regardless of the increased rate volatility associated with repeatedly seeking special assessments.

Q. Is it essential that the intervenors consider the solvency of the Storm Reserve when recommending a level for the annual accrual?

A. Yes. A solvency analysis provides a tool for management and policymakers to determine the performance of the Storm Reserve and to test whether annual accrual amounts meet their objectives. With rate stability as a policy objective, the question is what Storm Reserve balance should FPL seek to achieve and how quickly should it be reached to provide the desired stability in rates? That is a question addressed by Mr. Dewhurst in his testimony and should be a consideration in the Commission's decision. Once a proper Storm

Reserve balance is determined and achieved, an accrual that equals the expected annual damage will maintain this level in the Storm Reserve.

The ABS Consulting Solvency Analysis is a cash balance analysis starting with some initial balance, which is zero in this case. An annual accrual is added to the cash balance, and interest on the account balance at the end of the year is calculated and added to the account. Annual storm damage is simulated consistent with the Storm Loss Analysis for each of the five years. The storms are randomly simulated, but over a long period of time, they have an average of $73.7 million in damage to FPL's system for each of the five years in the solvency simulations.

For example, given that the expected annual damage is $73.7 million per year, if the Storm Reserve is funded at $73.7 million per year, which is the annual accrual suggested by Mr. Kollen and approximately the annual accrual suggested by Mr. Selecky, over a long period of time, the expected annual damage equals the annual accrual and the Reserve will not gain or loose value. Therefore, with a starting balance of zero, the expected balance of the Reserve will always hover around zero. At a balance of $0, any storm damage will have the effect of causing insolvency whenever it occurs. Likewise, if the beginning Storm Reserve balance is $250 million or $350 million, the balance will not grow if the annual accrual equals the expected annual damage. Rather, it will fluctuate around the beginning balance.

Q. Please respond to Ms. Merchant's assertion on page 21 that ABS Consulting's "solvency analysis does not contemplate that the annual accrual might be lowered by the Commission or that the utility might use another vehicle to replenish the storm reserve in a shorter timeframe."

A. The ABS Consulting Solvency Analysis has considered the current annual accrual of $20.3 million and demonstrated that it is inadequate to fund storm losses going forward with an initial Storm Reserve balance of zero. Ms. Merchant proposes the selective reduction of the limited FPL loss experience as the basis for her recommendation of an annual Storm Reserve accrual without addressing her own concern of the level to which the Storm Reserve balance should be replenished. Referring to the Solvency Analysis, Ms. Merchant states on page 21 that "[u]nless you agree 100% with the assumptions included in his analysis, I do not believe that his solvency analysis should be relied upon." The future performance of the Storm Reserve <u>cannot</u> be established without a financial simulation analysis that includes <u>both</u> the annual accrual and the beginning balance of the Storm Reserve. Ms. Merchant does not consider the starting Storm Reserve balance in making her recommendations, nor does she propose a target Storm Reserve balance.

Q. Please respond to Mr. Stewart's analysis on page 14 of his testimony, which demonstrated that the balance of the Storm Reserve would have been $745.5 million after the 2004 hurricane season if the annual accrual had been $120 million beginning in 1990.

A. In 1990, FPL did not need a $120 million annual Storm Reserve accrual because the Storm Reserve balance was $60 million and growing due to a favorable storm experience during the 1980s and because FPL's asset base was much smaller since FPL had fewer customers then. In addition, FPL had insurance through 1993, when it became unavailable. Viewed retrospectively, over the period from 1992 through 2004, FPL did need a higher annual accrual closer to the expected annual damage of $73.7 million. This is borne out by the first order estimate of the expected annual damage of $106 million performed by Ms. Merchant using a limited 12 years of loss history.

Currently, with a zero Storm Reserve balance, FPL has requested a $120 million annual accrual (approximately $70 million plus $50 million) to build the Storm Reserve balance up to a working target of $500 million that can fund for most but not all storms.

Q. Does ABS Consulting's Solvency Analysis show there is value in setting the annual accrual at a level higher than the expected annual damage?

A. Yes. Assuming an annual accrual of $70 million and a two-year recovery of negative balances, close to the expected annual damage, 50% of the time FPL's Storm Reserve will go insolvent within 5 years. If the annual accrual is $120 million and there is recovery of negative balances over a two-year period, the likelihood of insolvency goes down to 34%. Therefore, the value of accruing at a level higher than the expected annual damage until FPL's Storm Reserve reaches some substantial balance is a more rapid growth of the

Reserve balance and reduction in volatility, from insolvency one out of two years to insolvency one out of three years on average. This reduction in volatility would be seen in a reduced frequency of special assessment and a reduction of the levels of borrowing costs when the Storm Reserve does become insolvent from extraordinary storm years.

If the FPL Storm Reserve balance had been zero (as Mr. Kollen recommends) at the beginning of the 2004 storm season, the current deficit from storm restoration would be the full $890 million in uninsured damage. Providing a positive target balance for the Storm Reserve reduces the rate volatility and the recommended $120 million annual accrual would result, on average, in FPL requiring a special assessment for cost recovery every three years rather than every other year.

Q. **Have you analyzed the likelihood of Storm Reserve insolvency at the various annual accrual levels recommended by the intervenor witnesses?**

A. Yes. Document SPH-4, titled Storm Reserve Fund Analysis Case Results, demonstrates that the $20.3 million annual accrual recommended by Ms. Brown results in a 79% chance of insolvency in any one year of the five-year period both with and without recovery of negative balances over a two-year period. The expected fund balance at the end of five years with Ms. Brown's recommended accrual is negative $277 million with no recovery of negative balances in the Storm Reserve, and negative $71 million with recovery of negative balances over a two-year period.

The $35 million annual accrual recommended by Ms. Merchant results in a 68% chance of insolvency in any one year of the five years and an expected Reserve balance of negative $209 million without recovery of negative balances and negative $15 million with recovery.

At the $40 million accrual recommended by Mr. Stewart, there is a 64% chance of insolvency in any one year of the five-year period and an expected balance at the end of five years of negative $177 million with no recovery of negative balances and $11 million with recovery.

At an annual accrual of $70 million, recommended by Mr. Selecky and close to Mr. Kollen's $73.7 million recommendation, there is a 50% chance of insolvency in any one year of the five year period (or one out of two years). The expected balance at the end of five years is negative $14 million with no recovery of negative balances and $138 million with recovery of negative balances. The probability of insolvency at the end of five years is 34% and 17% for the 2 year recovery and no recovery cases respectively.

As stated in my direct testimony, the ABS Consulting analysis demonstrates that, at FPL's recommended annual accrual of $120 million, there is a 34% chance of insolvency in any one year of five years (or approximately one out of three years). At the end of five years, the expected balance in the Reserve is $256 million with no recovery of negative balances and $367 million with recovery of negative balances. The probability of insolvency at the end of five years is 19% and 8% for the 2 year recovery and no recovery cases respectively: about half the risk of insolvency for the $70 million accrual.

Q. **Please respond to Ms. Merchant's concern that "the storm reserve could grow to become quite large in a short time" if FPL's requested annual accrual is accepted.**

A. Her concern is unfounded. As the Solvency Analysis demonstrates, if FPL's annual accrual is accepted, the likelihood of FPL's Storm Reserve growing above $500 million within five-years is only about one in three. On the other hand, at Ms. Merchant's recommended annual accrual of $35 million, on average, special assessments should be expected in more than three out of every five years and customers would, in most years, see <u>two</u> special assessments on their bills. With these negative expected balances, the Storm Reserve would not be expected to fund anything but very small losses going forward and the funding mechanism would be come a de-facto "pay-as-you-go" policy using special assessments. Mr. Dewhurst addresses the problems of such an approach in his testimony.

Q. **Do the annual accrual levels recommended by witnesses Merchant, Brown, Selecky, Stewart and Kollen cover "normal" levels of storm damage or "smaller" storms?**

A. Not necessarily. The annual accrual levels proposed by these witnesses are too small to cover transmission and distribution (T&D) damage from even average Category 1 (SSI-1) storms that would make landfall in most of FPL's service territory.

Document SPH-4, page 2 of 4, shows the frequency-weighted average T&D damage from single SSI-1 storms, the least intense on the Saffir-Simpson Hurricane Scale, that could make landfall within 10 nautical miles of the specified mile post along FPL service territory. Document SPH-4 is similar to Figure 6-2 in Document SPH-1, which is attached to my direct testimony. Single SSI-1 landfalls near Miami, milepost 1480, have a mean (average) T&D damage of approximately \$73 million. Single SSI-1 landfalls near Sarasota, milepost 1240, have an average T&D damage of approximately \$20 million.

For a \$40 million annual accrual the expected Reserve balance of \$11 million after five years determined from the Solvency Analysis is not adequate to cover even the \$20 million SSI-1 T&D damage. For a \$40 million annual accrual, the Storm Reserve becomes insolvent for average SSI-1 landfalls anywhere in FPL's service territory since the damages are all greater than \$11 million. Document SPH-4, page 2 of 4, also shows that the \$70 million and \$120 million annual accruals, which result in expected Reserve balances of \$138 and \$367 million at the end of 5 years, would provide adequate funds for all SSI-1 T&D storm damage.

Document SPH-4, page 3 of 4, shows that the expected Storm Reserve balance at the end of five years for a $40 million accrual does not cover any of the SSI-3 storm landfalls at all. It would cover about 20% of the T&D damage for SSI-3 storms. A $70 million accrual and expected Reserve balance of $138 million at the end of five years will be adequate for some but not all SSI-3s. It will cover most of a strike to Sarasota, milepost 1240, which averages damage of $160 million. It will cover most landfalls from West Palm Beach north. It would not, however cover even half of the damage from mile posts 1450 to 1540; Dade and Broward counties, where damage averages in excess of $300 million. The $120 million accrual would cover most SSI-3 landfalls except the greatest damage in Miami at landfall mile posts 1470-1490.

Similarly, as seen on Document SPH-4, page 4 of 4, the expected Storm Reserve balance at the end of five years for a $40 million accrual doesn't cover any of the SSI-4 storm landfalls at all. A $70 million accrual and expected Reserve balance of $138 million at the end of five years would be adequate for only a few SSI-4 storms. For SSI-4 storms, the $367 million balance expected Storm Reserve balance covers only a portion of T&D damage in Miami-Dade, Broward and Palm Beach Counties, which have the highest asset concentrations in FPL's service area.

Based on Figure 6-6 on page 6-6 of the Loss Analysis (SPH-1), which is attached to my direct testimony, you see that even at a $120 million annual accrual, the expected $367 million balance at the end of five years would cover only a portion of the damage for most SSI-5 storm landfalls. For SSI-5 storms, the $367 million expected balance at the end of five years is only adequate to cover the least concentrated areas, which are in the northeast and southwest parts of FPL's service territory.

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

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF WILLIAM E. AVERA

DOCKET NOS. 050045-EI, 050188-EI

JULY 28, 2005

INTRODUCTION

Q. Please state your name and business address.

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

Q. Did you previously submit direct testimony in this proceeding?

A. Yes, I did.

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

A. My purpose here is to respond to the testimony of Dr. J. Randall Woolridge, submitted on behalf of the Office of Public Counsel (OPC), Mr. Matthew I. Kahal, on behalf of the Federal Executive agencies, Mr. Richard A. Baudino, on behalf of the South Florida Hospital and Healthcare Association, and Mr. James T. Selecky, on behalf of the Commercial Group (collectively, Intervenors) concerning a fair rate of return on equity (ROE) for Florida Power & Light Company (FPL). In addition, I also respond to the capital structure recommendations of Mr. Lane Kollen, on behalf of the South Florida Hospital and Healthcare Association, and the testimony of Kimberly Dismukes, on behalf of OPC, concerning the appropriate cost of capital to determine costs charged to FPL by FiberNet.

Q. Are you sponsoring an exhibit to your rebuttal testimony?

A. Yes. I am sponsoring an exhibit consisting of one document, Document WEA-13, which is attached to my direct testimony.

Q. What is your conclusion regarding Intervenors' ROE recommendations?

A. Investors have many potential options for their funds and competition for investment dollars is intense. As documented in my rebuttal testimony, Intervenors' cost of equity recommendations are significantly downward-biased and out of touch with the requirements of real-world investors in the capital markets. Considering investors' heightened awareness of the risks associated with the utility industry, supportive regulation remains crucial to maintaining FPL's access to capital and ensuring the Company's continued ability to meet customer needs, especially considering the challenges of its growing service area. Intervenors' recommendations would compromise these regulatory objectives and deny FPL the opportunity to earn its required rate of return.

DISCOUNTED CASH FLOW MODEL

Q. What cost of equity estimates were produced by Intervenors' application of the DCF method?

A. Based on his application of the constant growth DCF model to the 21 electric utilities in my proxy group, Dr. Woolridge concluded that the cost of equity for FPL is currently 8.8%, which was equal to his recommendation in this case. Meanwhile, Mr. Kahal concluded that the results of his DCF application indicated a midpoint cost of equity of 9.5%, while Mr. Baudino based his recommended rate of return on equity of 8.70% on a range of DCF cost of equity estimates from 8.39% to 9.02%.

Q. Is it reasonable to base FPL's fair rate of return solely on the results of the DCF method, as Dr. Woolridge and Mr. Baudino recommend?

A. No. As I noted in my direct testimony, because the cost of equity is unobservable, no single method should be viewed in isolation. While the DCF model has been routinely relied on in regulatory proceedings as one guide to investors' required return, it is a blunt tool that should never be used exclusively, and regulators have customarily considered the results of alternative approaches in determining allowed returns. The need to consider alternative methods is especially important where the results of one approach deviate significantly from cost of equity estimates produced by other applications, with risk premium methods suggesting a cost of equity far in excess of DCF values. Indeed, Mr. Baudino's alternative application of the Capital Asset Pricing Model (CAPM) resulted in indicated cost of equity estimates for his reference group of electric utilities of 11.32% and 11.55%, which he summarily rejected.

Q. Do you believe that the results of Intervenors' DCF analyses mirror investors' long-term expectations in the capital markets?

A. No. There is every indication that Intervenors' results are biased downward and fail to reflect investors' required rate of return. Short-term projected growth rates may be colored by current uncertainties regarding the near-term direction of the economy in general and the spate of challenges faced by utilities specifically. This short-term "hangover" is exemplified by Value Line, which has assigned its Utilities sector the lowest ranking of all 10 sectors it covers for year-ahead stock price performance,[1] while noting that "[t]he industry's Timeliness rank remains near the bottom of all industries we follow."[2] While this cautious outlook may be indicative of relatively

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[1] The Value Line Investment Survey, *Selection & Opinion* (Feb. 11, 2005) at 1878.

[2] The Value Line Investment Survey (Apr. 1, 2005) at 695.

low near-term growth projections, it is not necessarily indicative of investors' long-term expectations for the industry.

As Dr. Woolridge correctly observed:

> [T]o best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations. (p. 25)

But as Mr. Kahal recognized (p. 23), "[t]here are a number of reasons why investor expectations of long-run growth could differ from the limited, five-year earnings projections from securities analysts." If the near-term earnings growth projections used to apply the DCF model do not fully reflect the long-term expectations investors have built into stock prices, the resulting cost of equity estimates will be biased downward. Mr. Kahal noted (p. 22) that "historic measures have become quite volatile in recent years and therefore provide little (or questionable) useful guidance concerning expected long-term growth trends."

Indeed, as shown on Exhibit__(JRW-7), Dr. Woolridge's DCF cost of equity recommendation was based in part on a 2.6% average historical growth rate. Combining this growth rate with Dr. Woolridge's 4.00% average dividend yield results in a cost of equity estimate based on his historical growth measures of 6.6%. Meanwhile, Moody's reported an average yield on public utility bonds of approximately 5.6 percent for May 2005,[3] with the DCF estimate implied by Dr. Woolridge's historical growth rate exceeding this threshold by about 100 basis points. Considering the risk-return tradeoff principle fundamental to financial theory, it is

[3] Moody's Investors Service, *Credit Perspectives* (Apr. 18, 2005).

inconceivable that investors are not requiring a substantially higher rate of return for holding residual common stock, the riskiest of a utility's securities.

Q. Does the fact that analysts' projections may deviate from actual results hamper the use of earnings growth rates in applying the DCF model, as Dr. Woolridge contends (p. 56)?

A. No. In applying the DCF model to estimate the cost of equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information.

The continued success of investment services such as IBES and Value Line, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *Regulatory Finance: Utilities' Cost of Capital*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts also exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth]. ... Published studies in the academic literature demonstrate that growth forecasts made by securities analysts represent an appropriate source of DCF growth rates, are reasonable indicators of investor expectations and are more accurate than forecasts based on historical growth. ... Cragg and Malkiel (1982) presented detailed empirical evidence that the average analyst's expectation is more similar to expectations being reflected in the marketplace than are historical growth rates, and that they represent the best possible source of DCF growth rates.[4]

Similarly, Mr. Baudino noted in his testimony (p. 28) that "[t]he finance literature has shown that analysts' forecasts provide better predictions of future growth than do estimates based on historical growth alone," while Mr. Kahal recognized (p. 23) that earnings growth projections of securities analysts are "one particularly useful source of information on prospective growth."

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[4] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," Public Utilities Reports, Inc. (1994) at 154-155.

Q. What about Dr. Woolridge's contention (p. 56-60) that the analysts' earnings growth projections you used in applying the DCF model are biased?

A. First, in contrast to Dr. Woolridge's allegations, a study reported in "Analyst Forecasting Errors: Additional Evidence" found no optimistic bias in earnings projections for large firms (market capitalization of $500-$3,000 million), with data for the largest firms (market capitalization > $3,000 million) demonstrating a *pessimistic* bias.[5]

More importantly, however, any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. In using the DCF model to estimate investors' required returns, the purpose is not to prejudge the accuracy or rationality of investors' growth expectations. Instead, to accurately estimate the cost of equity we must base our analyses on the growth expectations investors actually used in determining the price they are willing to pay for common stocks – even if we do not agree with their assumptions. As Robert Harris and Felicia Marston noted in their article in *Journal of Applied Finance*:

> There is very little research on the properties of five-year growth forecasts, as opposed to short-term predictions.
>
> ...Analysts' optimism, if any, is not necessarily a problem for the analysis in this paper. If investors share analysts' views, our

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[5] Brown, Lawrence D., "Analyst Forecasting Errors: Additional Evidence," *Financial Analysts Journal* (November/December 1997).

procedures will still yield unbiased estimates of required returns and risk premia.[6]

Dr. Woolridge's figures and graphs notwithstanding, the earnings growth projections of security analysts provide the most frequently referenced guide to the views of real-world investors in the capital markets. As a result, Dr. Woolridge's criticism of the use of analysts' growth rates in applying the DCF model lacks any meaningful foundation.

Q. Did Dr. Woolridge provide any support for his allegation that Value Line forecasts are "upward biased" (p. 60)?

A. No. After noting that he was unaware of any studies to support his conclusion, Dr. Woolridge simply asserted his personal belief that Value Line projections are "inflated and unrealistic." But Dr. Woolridge's personal opinions are irrelevant to a determination of what investors expect and, contrary to his conclusion, Value Line is a well-recognized source in the investment and regulatory communities. Given the fact that Value Line is perhaps the most widely available source of information on common stocks, the projections of Value Line analysts provide an important guide to investors' expectations. Moreover, in contrast to Dr. Woolridge's unsupported assertion, the fact that Value Line is not engaged in investment banking or other relationships with the companies that it follows reinforces its impartiality in the minds of investors.

[6] Harris, Robert S. and Marston, Felicia C., "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," *Journal of Applied Finance* 11 (2001) at 8.

Q. Is there a downward bias inherent in Intervenors' application of the DCF model based on the internal, br+sv growth rate?

A. Yes. Dr. Woolridge and Mr. Baudino based their calculation of the internal, "br" growth rate on projection from Value Line, which reports end-of-period results. If the rate of return, or "r" component of the "br" growth rate is based on end-of-year book values, such as those reported by Value Line, it will understate actual returns because of growth in common equity over the year. This downward bias, which has been recognized by regulators,[7] is illustrated in the table below.

Consider a hypothetical firm that begins the year with a net book value of common equity of $100. During the year the firm earns $15 and pays out $5 in dividends, with the ending net book value being $110. Using the year-end book value of $110 to calculate the rate of return produces an "r" of 13.6 percent. As the Federal Energy Regulatory Commission (FERC) recognized, however, this year-end return "must be adjusted by the growth in common equity for the period to derive an average yearly return."[8] In the example below, this can be accomplished by using the *average* net book value over the year ($105) to compute the rate of return, which results in a value for "r" of 14.3 percent. Use of the average rate of return over the year is consistent with the theory underlying this approach to estimating investors' growth expectations, and as illustrated below, it can have a significant impact on the calculated br+sv growth rate:

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[7] See, *e.g.*, *Southern California Edison Company,* Opinion No. 445 (Jul. 26, 2000), 92 FERC ¶ 61,070.
[8] *Id.*

Beginning Net Book Value	$100
Earnings	
Dividends	
Retained Earnings	$ 10
Ending Net Book Value	$110
"br" Growth – End of Year	
Earnings	$ 15
Book Value	$110
"r"	13.6%
"b"	66.7%
"br" Growth	**9.1%**
"br" Growth – Average	
Earnings	$ 15
Book Value	$105
"r"	14.3%
"b"	66.7%
"br" Growth	**9.5%**

Because Dr. Woolridge and Mr. Baudino did not adjust to account for this reality in their analysis, their "br" growth rates are downward-biased and the resulting DCF cost of equity is understated.

Q. What other consideration leads to a downward bias in Intervenors' DCF analyses using internal, "br" growth?

A. Intervenors failed to consider the impact of additional issuances of common stock in their analysis of the internal growth rate. As discussed in my direct testimony (p. 40) 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. As noted by Myron J. Gordon in his 1974 study:

> When a new issue is sold at a price per share P = E, the equity of the new shareholders in the firm is equal to the funds they contribute, and the equity of the existing shareholders is not changed. However, if P > E, part of the funds raised accrues to the existing shareholders.

> Specifically…[v] is the fraction of the funds raised by the sale of stock that increases the book value of the existing shareholders' common equity. Also, "v" is the fraction of earnings and dividends generated by the new funds that accrues to the existing shareholders.[9]

In other words, the "sv" factor is an adjustment required by the DCF approach to ensure that the growth rate "g" is properly calculated for firms that plan to issue new common stock in the coming years. Ignoring these planned stock issues that are projected by Value Line distorts internal growth rates since investors using Value Line would incorporate the impact of future stock issues in making their assessment of the growth they expect when they purchase the company's common stock.

Q. Did Intervenors adequately recognize the importance associated with reliance on multiple methods and approaches in estimating the cost of equity?

A. No. Apart from applications of the CAPM approach, which I address subsequently, Intervenors' ignored the results of other risk premium methods to check or validate their results. And even though Dr. Woolridge and Mr. Baudino apply the CAPM, their recommendations were based only on the results of the constant growth DCF model. As I explained in my direct testimony, however, 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. Considering the results of alternative methods and approaches provides greater confidence that the end result is reflective of investors' required rate of return. *Regulatory Finance: Utilities' Cost of Capital* (Public Utilities Reports, Inc., 1994) concluded that:

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[9] Gordon, Myron J., "The Cost of Capital to a Public Utility," MSU Public Utilities Studies (1974), at 31 –32.

> When measuring equity costs, which essentially deal with the measurement of investor expectations, no one single methodology provides a foolproof panacea. If the cost of equity estimation process is limited to one methodology, such as DCF, it may severely bias the results. (p. 238)

Q. Do the results of alternative methods support Intervenors' cost of equity recommendations in this case?

A. No. Even without incorporating expectations for higher interest rates, as noted in my direct testimony, application of the risk premium approach based on allowed rates of return for electric utilities resulted in a current cost of equity of 10.6% (p. 45), while applying the CAPM based on forward-looking expectations that are more consistent with the underlying theory of this approach produced an estimated cost of equity of 11.8 percent (p. 49). Similarly, Mr. Baudino concluded that the CAPM approach implied a cost of equity for FPL on the order of 11.32% to 11.55% (p. 38). These estimates confirm the downward bias present in Intervenors' DCF results.

Q. What other evidence indicates that Intervenors' cost of equity recommendations for FPL are biased downward?

A. Reference to allowed rates of return for other utilities also provides further confirmation that Intervenors' recommendations fall significantly short of a reasonable rate of return. The rates of return on common equity authorized electric utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates (RRA) and published in its *Regulatory Focus* report. RRA reported average authorized ROEs of 10.91 and 10.36 percent for electric utilities for the fourth quarter of 2004 and first half of 2005, respectively. Meanwhile, Mr.

Selecky noted (p. 5) that the average return authorized for electric utilities in 2004 was 10.7%. These recent authorized returns exceed Intervenors' recommendations by 100 to 200 basis points.

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 most recent edition of Value Line (July 1, 2005) reports that its analysts expect an average rate of return on common equity for the electric utility industry of 11.5% over its three-to-five year forecast horizon. Even Dr. Woolridge was forced to grant (p. 48) that his recommendation "is low by historic standards."

Q. Did Mr. Selecky conduct any independent analyses of the cost of equity to FPL?

A. No. While Mr. Selecky implied (p. 5) that FPL's requested ROE was "excessive," he conducted no independent analyses or research to estimate investors' required rate of return. Rather, Mr. Selecky merely observed that FPL's request exceeded recent authorized returns. I agree that authorized rates of return can provide a meaningful benchmark in evaluating investors' required rates of return; however, the study that was included as Document WEA-6 to my direct testimony presents a comprehensive evaluation of this information, with the results supporting my recommendations and conclusions.

Q. Do Intervenors present any meaningful evidence that would warrant their decision to ignore the results of alternative approaches to estimate the cost of equity?

A. No. Dr. Woolridge argues (p. 32) that the CAPM is "difficult to measure because it requires an estimate of the expected return on the market." Similarly, Mr. Baudino observes (pp. 34-35) that applying the CAPM requires "a considerable amount of judgment," which "can significantly influence the results." Of course, this comes as no surprise given that investors' expectations and their required rate of return are both unobservable. In fact, the very same criticisms can be leveled at the DCF model, which requires an estimate of investors' growth expectations and the exercise of considerable judgment in order to estimate the cost of equity. The fact that risk premium methods, like the DCF model, require estimates and cannot be applied in a mechanical manner provides no basis to ignore these widely-recognized approaches to estimate the cost of equity.

Q. Do you agree with the assertions of Mr. Baudino and Mr. Kahal that certain companies should be excluded from your proxy group?

A. No. While Dr. Woolridge adopted my proxy group for purposes of his analysis, Mr. Baudino argued that certain companies should be dropped, largely based on subjective arguments concerning the impact of non-regulated operations. Similarly, Mr. Kahal argued for the elimination of companies based on an assessment of the degree of regulatory restructuring at the retail level. However, neither witness demonstrated how their subjective criteria translate into differences in the investment risks perceived by investors. Moreover, there are significant errors and inconsistencies associated with their approach that justify rejecting their proxy groups altogether.

Q. Did Mr. Baudino and Mr. Kahal demonstrate a nexus between the subjective criteria they used to define their proxy groups and objective measures of investment risk?

A. No. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criteria in establishing a meaningful proxy group to estimate investors' required return is relative risk, not the source of the revenue stream or the degree of regulatory restructuring. As Mr. Baudino correctly recognized (p. 17):

> The key element in deciding whether to invest, however, is based on comparative levels of risk. One hypothetical investor would not invest in a particular electric company stock if it offered a return lower than other investments of similar risk.

Neither Mr. Baudino nor Mr. Kahal presented any evidence that there is a connection between the subjective criteria that they employed and the views of real-world investors in the capital markets.

Q. What objective evidence can be evaluated to confirm the conclusion that these subjective criteria are not synonymous with comparable risk in the minds of investors?

A. Bond ratings are perhaps the most objective guide to utilities' overall investment risks and they are widely cited in the investment community and referenced by investors. 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).[10]

Indeed, Mr. Baudino stated (p. 19) that:

> Bond ratings are another good tool that investors may utilize to determine the risk comparability of firms.

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services and rating agencies also provide relative assessments of risk that are considered by investors in forming their expectations. For example, Value Line's Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest), is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. Mr. Baudino (p. 19) characterized the Safety Rank as "[o]ne of the best-known and most widely available" measures of investment risk.

As I noted in my direct testimony (p. 33), my proxy group of 21 electric utilities had corporate credit ratings of "BBB+" or above, with an average rating of single-A. As shown in the table below, credit ratings assigned to the nine utilities excluded by Mr. Baudino based on his revenue test ranged from "BBB" to "A", while the Safety Rank ranged from "1" to "3":

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[10] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utility Reports* (1994) at 81.

Group	S&P Credit Rating		Value Line Safety	
	Higher Risk	Lower Risk	Higher Risk	Lower Risk
Excluded by Baudino (Revenue)	BBB	A	3	1
Baudino Proxy Group	BBB+	A	3	1

As shown in the table above, a comparison of these objective risk indicators demonstrates that the range of risks for the companies eliminated under the subjective criteria proposed by Mr. Baudino are virtually identical to measures for the companies included in their proxy groups.

Q. **What do you conclude from the analysis of different independent, objective risk factors used by the investment community?**

A. Contrary to the allegations of Mr. Baudino, comparisons of objective, published indicators that incorporate consideration of a broad spectrum of risks, confirm that there is no link between the subjective test he applied to define his proxy groups and the risk perceptions of investors. Similarly, Mr. Kahal has presented no evidence to demonstrate any link between his proxy group criteria and investment risk.

Q. **What errors and inconsistencies are associated with the proxy groups proposed by Mr. Baudino and Mr. Kahal?**

A. While Mr. Baudino proposes to eliminate nine companies from my proxy group based on the proportion of revenues from regulated utility operations, many of the figures he relied on to make this discrimination are incorrect. For example, DTE Energy reported in its 2004 Form-10K report (Note 16) that operating revenues from "utility" sources totaled approximately $5.3 billion, or 75% of total operating revenues of $7.1 billion – not the 18% relied on by Mr. Baudino. Meanwhile, SCANA reported that revenues from its regulated electric utility, gas distribution, and gas transmission operations totaled \$2.8 billion in 2004, or 72% of total consolidated revenues of \$3.9 billion (2004 Form 10-K at Note 11), while Sempra Energy recorded revenues from regulated utility operations of approximately \$6.3 billion during 2004, or 67% of total revenues of \$9.4 billion (2004 Form-10K Report at Note 17). Meanwhile, Mr. Baudino erroneously reported that regulated revenues for SCANA and Sempra Energy amounted to 43% and 48% of total revenues, respectively. Similarly, Vectren Corporation's utility group posted 2004 revenues of \$1.5 billion, or 88% of the \$1.7 billion in total revenues (2004 Form-10K at Note 16), while Mr. Baudino mistakenly claimed that regulated revenues amounted to only 22%. Thus, even accepting his erroneous revenue criteria, Mr. Baudino should not have excluded DTE Energy, SCANA, Sempra Energy, and Vectren Corporation.

Q. Apart from these errors are there problems associated with the revenue criteria proposed by Mr. Baudino?

A. Yes. Due to differences in business segment definition and reporting between utilities, it is often impossible to accurately apportion financial measures, such as total revenues, between utility and non-utility sources. Consider the example of OGE Energy, which Mr. Baudino argued should be excluded from the proxy group. OGE Energy classifies its operations into two primary segments – Electric Utility and Natural Gas Pipeline, with revenues attributable to the electric utility segment accounting for approximately 32% of consolidated revenues in 2004 (Form 10-K at Note 16). However, this does not present an accurate picture of "revenues coming from regulated utility operations" because a portion of the revenues included in the Natural Gas Pipeline segment also relate to rate regulated operations. As ONG Energy reported to investors in its 2004 Form-10K:

> The operations of the Natural Gas Pipeline segment are conducted through Enogex Inc. and its subsidiaries ("Enogex") and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. ... Enogex also owns a controlling interest in and operates Ozark Gas Transmission, L.L.C. ("Ozark"), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri.

As a result, even ignoring the fact that there is no clear link between the source of a utility's revenues and investors' risk perceptions, it is not possible to accurately apply Mr. Baudino's criteria.

Q. What other inconsistencies argue for rejecting the proxy groups proposed by Mr. Baudino and Mr. Kahal?

A. Not surprisingly, the result of the subjective criteria proposed by Mr. Baudino and Mr. Kahal is a hodgepodge of conflicting recommendations as to what constitutes a "comparable" utility. For example, Mr. Baudino rejects SCANA, Vectren Corporation, and WPS Resources from consideration, while Mr. Kahal includes all of these firms in his proposed proxy group. Meanwhile, Mr. Baudino asserts (p. 26) that the bond ratings of the firms in his proxy group are comparable to FPL, while Mr. Kahal ignores credit ratings altogether. Indeed, one of the companies that Mr. Kahal includes in his proxy group – Westar Energy – is actually rated "BB+" by S&P. While Westar Energy has recently made progress in improving its finances, this below investment grade credit rating places it in the same category as speculative grade, or "junk" securities. Aside from the fact that Westar's credit rating is not at all comparable to FPL, the disruptions that accompany a speculative grade rating can hinder the application of quantitative methods, such as the DCF model, to estimate investors' required return. Given these errors and inconsistencies, the proxy groups proposed by Mr. Baudino and Mr. Kahal should be rejected.

RISK PREMIUM

Q. What is the fundamental problem associated with Dr. Woolridge's approach to applying the CAPM?

A. Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return the CAPM must be applied using data that reflects the expectations of actual investors in the market. However, while Dr. Woolridge concluded (p. 64-65) that "historic data does not provide a realistic or accurate barometer of expectations of the future," his application of the CAPM method was entirely premised on *historical* – not projected – rates of return. By failing to look directly at the returns investors are currently requiring in the capital markets, as I did on Document WEA-9, Dr. Woolridge's CAPM estimate significantly understates investors' required rate of return.

Q. Is there anything forward-looking about the academic studies referenced by Dr. Woolridge?

A. No. As Dr. Woolridge explained (p. 44), his CAPM analysis was based in part on a 4.0 percent risk premium determined from his review of an August 2003 working paper that summarized the risk premiums reported in various academic studies. Rather than looking directly at the returns investors might currently be requiring in the capital markets, Dr. Woolridge predicated his CAPM study on a summary of *historical* results from selected studies reported in the academic and trade literature.

These selected studies do not examine the forward-looking expectations of today's investors to estimate the required market rate of return in current capital markets. Instead of directly considering requirements in today's capital markets, Dr. Woolridge is implicitly asserting that events and expectations for the time periods covered by these selected studies are more representative of what is likely to occur going forward. This assertion runs counter to the assumptions underlying the use of the CAPM to estimate investors' required return. The primacy of current expectations was recognized by Ibbotson Associates in their *2003 Yearbook, Valuation Edition*:

> The cost of capital is always an expectational or forward-looking concept. While the past performance of an investment and other historical information can be good guides and are often used to estimate the required rate of return on capital, the expectations of future events are the only factors that actually determine cost of capital. (p. 23)

Moreover, even if historical studies were relevant in this context, there are any number of other such studies of equity risk premiums published in academic journals that imply required rates of return considerably in excess of those relied on by Dr. Woolridge. For example, a study reported in the *Financial Analysts' Journal* noted that the real risk premium for U.S. stocks averaged 6.9 percent over the period 1889 through 2000 and concluded that:

> Over the long term, the equity risk premium is likely to be similar to what is has been in the past and returns to investment in equity will

continue to substantially dominate returns to investments in T-bills for investors with a long planning horizon.[11]

Combining this 6.9% risk premium with a 3.0% inflation rate and Dr. Woolridge's 4.50% risk-free rate implies a current required rate of return on equity for the market as a whole of 14.4% – far in excess Dr. Woolridge's 8.2%, computed as the sum of his 3.7% market risk premium and 4.5% risk-free rate (p. 44).

Q. **Do the results of the underlying equity risk premium studies relied on by Dr. Woolridge all make economic sense?**

A. No. In fact, three of the studies included on Exhibit __ (JRW-8) as support for Dr. Woolridge's CAPM analysis reported *negative* equity risk premiums. In other words, these studies apparently concluded that investors' required rate of return on common stocks was *below* the return on risk-free debt. Similarly, other historical studies included in Dr. Woolridge's assessment found market equity risk premiums of 3.0% or below. But multiplying a market equity risk premium of 3.0% by Dr. Woolridge's beta of 0.78 for the electric utility proxy group, and combining the resulting 2.34% risk premium with his 4.5% risk-free rate, results in an indicated cost of equity of approximately 6.8%. By any objective measure, such results fall woefully short of required returns from an investment in common equity and confirm that Dr. Woolridge's CAPM cost of equity has little relation to the expectation of real-world investors.

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[11] Mehra, Ranjnish, "The Equity Premium: Why Is It a Puzzle?", *Financial Analysts' Journal* (January/February 2003).

Q. Are the results of Dr. Woolridge's "building block" approach (pp. 36-43) any more indicative of forward-looking, *ex-ante* expectations?

A. No. Dr. Woolridge noted (p. 32-33) that historical results are not the same as future expectations, and that the risk premium approach – including the CAPM – should be applied using forward-looking information. Meanwhile, Dr. Woolridge applied his "building block" approach based on backward-looking, historical data for certain key variables. For example, Dr. Woolridge noted (p. 41) that the "RG" component of his estimated market return was based on "the average of the *historic* S&P EPS real growth and the *historic* real GDP growth." Similarly, his conclusion that investors would not expect any further increases in the P/E ratios of common stocks going forward was based largely on his review of P/E ratios for the S&P 500 over the last 25 years (p. 41-42).

Q. What evidence demonstrates that Dr. Woolridge's "building block" approach rests on a weak foundation?

A. Dr. Woolridge based his "building block" analysis of the market equity risk premium on an article by Roger G. Ibbotson and Peng Chen, published in *Financial Analysts' Journal* ["Long-Run Stock Returns: Participating in the Real Economy," January/February 2003]. But Dr. Woolridge's conclusions differ markedly from those of the article on which his "building blocks" approach was based. Based on the results of their study, Ibbotson and Chen concluded that:

> Our forecast of the equity risk premium is only slightly lower than the pure historical return estimate. We estimate the expected long-term equity risk premium … to be about 6 percentage points arithmetically… (p. 88)

Meanwhile, Dr. Woolridge asserted that the methods outlined by Ibbotson and Chen currently suggest a market risk premium of 3.4%. In other words, Dr. Woolridge is contending that the market equity risk premium has decreased by approximately 2.6% -- a decline of over 43% -- since the time Ibbotson and Chen published their study in early 2003. Of course, there is no underlying capital market evidence for such a tremendous shift in the market equity risk premium. The fact that the results of Dr. Woolridge's "building blocks" approach cannot be reconciled to observable capital market trends or the results of the study on which it was based demonstrate the fatal flaws inherent in his method.

Q. Does the *Survey of Professional Forecasters,* cited repeatedly by Woolridge (p. 39, 41, 43, 74), provide any meaningful corroboration or guidance as to investors' required rate of return?

A. No. The *Survey of Professional Forecasters* is not an investment advisory publication; nor is this report focused on serving as a resource for stock market investors. Rather, this survey primarily targets broad indicators of macroeconomic performance, such as GDP and its components, unemployment rates, industrial production, and inflation. While the survey may provide a useful resource for policymakers and in general business planning, it is not widely referenced by investment professionals as a guide to stock market performance or routinely used in estimating investors' required rate of return.

Indeed, as Dr. Woolridge notes at pages 45-46, the *Survey of Professional Forecasters* apparently predicts that equity returns will exceed the yields on 10-year Treasury bonds by 200 basis points. But with 10-year Treasuries yielding an average of 4.13 percent in May 2005 (Moody's Credit Perspectives, June 20, 2005), this implies an expected return on the S&P 500 of 6.13 percent under Dr. Woolridge's paradigm. Meanwhile, Moody's reported that the average yield on triple-B corporate bonds was 6.05 percent during May 2005 (Credit Perspectives, June 20, 2005 at 63). Why would rational investors buy a basket of common stocks, and assume all the inherent risk, when they could earn almost the same expected return with certainty by buying a bond? The answer, of course, is that rational investors would not. Considering that this return falls over 250 basis points below even Dr. Woolridge's meager 8.80 percent cost of equity recommendation for an electric utility, it is clearly nonsensical.

Q. Do the risk premiums "of leading investment firms" cited by Dr. Woolridge at pages 44-45 provide any support for his conclusions?

A. No. Like the data from the *Survey of Professional Forecasters*, these observations provide no meaningful guidance as to a fair rate of return for FPL. Dr. Woolridge cites a market risk premium "in the 2.0 to 3.0 percent range" (p. 45) based on his two selected sources. Multiplying the 2.5% midpoint of this range by Dr. Woolridge's beta value of 0.78, and then adding the resulting 1.95% risk premium to his 4.5% risk free rate, results in an implied cost of equity for an electric utility of 6.45%. In light of the yields available on long-term debt and recent authorized rates of return, plain common sense tells us that this result is simply meaningless. Rather than confirming Dr. Woolridge's testimony, it provides one more indication of just how far his analyses and opinions are from those of investors in the capital markets.

Q. What about Dr. Woolridge's reference to the risk premiums of "leading consulting firms" (p. 46)?

A. Dr. Woolridge's reference to a 2002 Mckinsey & Co. study demonstrates the fallacy of his focus on selected historical information to apply the CAPM. As Dr. Woolridge noted, in an effort to explain their observations regarding the behavior of equity risk premiums, McKinsey & Co. concluded that equities had not become less risky. Rather, they surmised that investors' required returns on government bonds had increased due to concerns over the potential impacts of "inflation shocks." Over the past several years, however, long-term government bonds have been largely viewed as a safe haven as stock market volatility and a resulting "flight to quality" drove bond yields steadily lower. While investors recognize the potential for inflation to increase as the economy strengthens, there is no evidence that an anticipated "inflation shock" similar to those of the 1970s has led to a secular decline in the equity risk premium going forward. As Dr. Woolridge noted:

> The equity risk premium is based on expectations of the future. When past market conditions vary significantly from the present, historic data does not provide a realistic or accurate barometer of the future. (p. 70)

Considering that the historical premise underlying the conclusions of the McKinsey study does not reflect current capital market expectations, this reference provides no useful information in gauging investors' current required rates of return.

Q. Does Dr. Woolridge (pp. 6-7) accurately characterize the statements of Alan Greenspan?

A. No. Dr. Woolridge's selective quotation ignores both the context and the message of Mr. Greenspan's remarks. First, it is important to note that Mr. Greenspan's comments were made in October 1999, at a time of when sharply rising equity valuation were giving rise to concern over "irrational exuberance." Rather than predicting continued expectations for lower risk premiums, Mr. Greenspan's October 1999 speech warned his audience not to be complacent. Mr. Greenspan noted that any decline in equity risk premiums could prove to be temporary – an observation that was borne out by the subsequent collapse in equity values – and he specifically predicted that sharply rising risk premiums could lead to crisis if not addressed beforehand. As Mr. Greenspan noted:

> …history tells us that sharp reversals in confidence can occur abruptly, most often with little advance notice. These reversals can be self-reinforcing processes that can compress sizeable adjustments into a very short period. … The uncertainties inherent in valuations of assets and the potential for abrupt changes in perceptions of those uncertainties clearly must be adjudged by risk managers…[12]

Rather than supporting Dr. Woolridge's anemic ROE recommendation, Mr. Greenspan's cautions over the potential for swift and sharp reversals is entirely consistent with my testimony that adequate support for FPL's financial integrity is

[12] "Measuring Financial Risk in the Twenty-first Century," *Remarks by Alan Chairman Greenspan* (Oct. 14, 1999).

essential to ensure that customers continue to receive the high level of service they have come to expect from the Company.

Q. Is there anything wrong with the approach that you employed to determine the equity risk premium for your forward-looking CAPM analysis (Document WEA-9)?

A. No. As explain in my direct testimony, I estimated the current equity risk premium by first applying the DCF model to estimate investors' current required rate of return for the firms in the S&P 500 and then subtracting the yield on government bonds. Dr. Woolridge and Mr. Kahal contend that this CAPM analysis is flawed because of an alleged upward bias in the analysts' growth estimates used to estimate investors' expected return on the S&P 500.

The fallacy of these arguments was addressed earlier in my discussion of the DCF model. Moreover, Intervenors all rely on analysts estimates in applying the DCF model and the use of forward-looking expectations in estimating the market risk premium is well accepted in the financial literature. For example, in "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts" [*Journal of Applied Finance*, Vol. 11 No. 1, 2001], Robert S. Harris and Felicia C. Marston employed the DCF model and earnings growth projections from IBES – just as I did in Document WEA-9, to estimate the required rate of return on the S&P 500. Similarly, the table on page 33 of Dr. Woolridge's testimony noted that:

> Current financial market prices (simple valuation ratios or DCF-based measures) can give most objective estimate of feasible ex ante equity-bond risk premium.

Dr. Woolridge went on to note (p. 35) that "Fama and French conclude that ex ante equity risk premium estimates using DCF models and fundamental data are superior to those using ex post historic stock returns." In fact, this application of the DCF model to the S&P 500 using current financial market data is exactly the approach reflected in my forward-looking application of the CAPM presented in Document WEA-9.

Dr. Woolridge's complaints about my forward-looking CAPM approach seem to hinge on the fact that this method produces an equity risk premium for the S&P 500 that is considerably higher than the unrealistic benchmarks he cites. But as I explained earlier, the benchmarks cited by Dr. Woolridge fail even the most rudimentary tests of economic logic. Estimating investors' required rate of return by reference to current, forward-looking data, as I have done, is entirely consistent with the theory underlying the CAPM methodology. As noted earlier, the CAPM is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of required rates of return, the CAPM is best-applied using data that reflects the expectations of actual investors in the market. Rather than look backwards to a select subset of academic studies, or a "building blocks" risk premium based largely on historical data, as Dr. Woolridge advocates, my analysis appropriately focused on the expectations of actual investors in today's capital markets.

Q. Is there any basis for Mr. Kahal's characterization of your forward-looking CAPM analysis as "optimistic" (p. 36)?

A. No. Rather than citing a single "top-down" growth rate, such as those referenced by Mr. Kahal, my analysis relied on the individual consensus growth forecasts of securities analysts for each of the firms included in the S&P 500. This "bottom-up" approach results in a more all-encompassing growth rate that considers expectations for each of the individual firms making up the market index. Moreover, as noted earlier this very same approach has been adopted in recognized studies reported in the financial literature. Similarly, contrary to Mr. Kahal's suggestion that the 9.3 percent market risk premium estimated in my analysis is "optimistic", the results of the *Financial Analysts' Journal* study cited earlier implies a market risk premium of 9.9 percent.

Finally, I find it ironic that Mr. Kahal would advocate a "top-down" growth rate for the S&P 500 while ignoring comparable information for the electric utility industry. For example, Zacks Investment Research, which Mr. Kahal cites (p. 36) as a source of "top-down" growth estimates for the S&P 500, reports an expected 5-year growth rate for its "UTIL-ELEC PWR" industry of 7.2%. This growth rate, combined with Mr. Kahal's adjusted dividend yield of 4.3%, implies a cost of equity for an electric utility of 11.5%.

Q. Did Mr. Baudino employ a similar approach to apply the CAPM?

A. Yes. Using data for the companies followed by Value Line, Mr. Baudino (p. 35) combined an average growth rate of 12.70% with an average dividend yield of 1.18% to estimate a required rate of return on the market of 13.88%, which is identical to my forward-looking market return of 13.9% (Document WEA-9). Based on this market rate of return, Mr. Baudino concluded (p. 38) that the CAPM implied a cost of equity of 11.55% based on 20-year Treasury bond yields.

Q. Did Mr. Baudino present any meaningful basis for ignoring the results of his CAPM analysis?

A. No. Mr. Baudino's decision to ignore his CAPM results was based on his belief that 1) "historical betas are ... likely to fall from their current level" (p. 40); and 2) "the expected return on the market ... appears to be quite volatile" (p. 41). Neither of these assertions justifies Mr. Baudino's decision to ignore the results of the CAPM approach. First, as discussed in detail in my direct testimony, there is every indication that the electric utility industry will continue to face volatility and ongoing challenges associated with wholesale market restructuring. Additionally, there is no objective evidence to support Mr. Baudino's conclusion that beta values for electric utilities are on a decline. Similarly, considering the inherent uncertainties involved in estimating the cost of equity, the 50 basis-point shift in the estimated market rate of return cited by Mr. Baudino is hardly an indictment of the CAPM. Indeed, similar changes could just as easily occur when applying the DCF model to estimate the cost of equity for electric utilities. Mr. Baudino's observation (p. 34) that "a considerable amount of judgment must be employed" to use the CAPM applies just as readily to the DCF model.

Q. Do you agree with Intervenors that it is not appropriate to consider expected increases in capital costs when establishing the allowed ROE for FPL?

A. No. While Intervenors observe that the projected long-term bond yields referenced in my analysis have not yet been realized, they also grant that yields are currently at all-time lows compared with the recent past and that there is "uncertainty over the economy and interest rates" (Woolridge, p. 64). In fact, it is this very realization, and the general expectation that long-term capital costs will move higher, that warrants consideration of widely referenced forecasts of future bond yields.

On June 30, 2005 the Federal Reserve raised interest rates for the ninth time since June 2004 and has signaled it is likely to continue to act at a "measured" pace. Expectations remain that these actions will also translate into higher long-term interest rates. Indeed, the most recent edition of the *Survey of Professional Forecasters* [Second Quarter 2005] cited by Dr. Woolridge expects that 10-year Treasury bond yields will increase approximately 1.1 percent between 2005 and 2006. Value Line recently noted the impact that readjustments in capital market conditions – in the form of higher interest rates – would have on investors' assessment of utility stocks:

> [I]f interest rates continue to rise, as we are projecting, some positive attributes that come with owning an income stock may be reduced.[13]

Consideration of interest rate forecasts does not presume that financial markets are "wrong"; rather, it recognizes that investors' required returns can and do shift over time with changes in capital market conditions.

Competition for capital is intense, and electric utilities such as FPL must be granted the opportunity to earn an ROE comparable to contemporaneous returns available from alternative investments if they are to maintain their financial flexibility and ability to attract capital. Expected capital market conditions during the time when rates established in this proceeding will be in effect are certainly one very valid barometer in ensuring that this fundamental economic and regulatory test is met.

[13] The Value Line Investment Survey (Mar. 18, 2005) at 459.

Moreover, as I noted in my direct testimony, consideration of interest rate forecasts is also consistent with the methodology employed at the FPSC in the past. Indeed, Mr. Kahal granted (p. 34) that the FPSC "may wish to consider ... interest rate projections ... in selecting a final ROE award for FPL."

Q. Is Dr. Woolridge correct when he claims on page 67 that the arithmetic mean is "biased" so that the geometric mean should be the sole measure of average rate of return?

A. No, absolutely not. Both the arithmetic and geometric means are legitimate measures of average return; they just provide different information. Each may be used correctly, or misused, depending upon the inferences being drawn from the numbers. I am particularly sensitive to Dr. Woolridge's mischaracterization of these measures since my Ph.D. dissertation dealt with the proper use of the geometric mean by investors.

The geometric mean of a series of returns measures the constant rate of return that would yield the same change in the value of an investment over time. The arithmetic mean measures what the expected return would have to be each period to achieve the realized change in value over time. In estimating the cost of equity, the goal is to replicate what investors expect going forward, not to measure the average performance of an investment over an assumed holding period. Under the realized rate of return approach, investors consider the equity risk premiums in each year independently, with the arithmetic average of these annual results providing the best estimate of what investors might expect in future periods. *Regulatory Finance: Utilities' Cost of Capital* (1994) had this to say:

> One major issue relating to the use of realized returns is whether to use the ordinary average (arithmetic mean) or the geometric mean return. *Only arithmetic means are correct for forecasting purposes and for estimating the cost of capital.* When using historical risk premiums as a surrogate for the expected market risk premium, the relevant measure of the historical risk premium is the arithmetic average of annual risk premiums over a long period of time. (p. 275, emphasis added)

Similarly, Ibbotson Associates concluded in its *2004 Yearbook, Valuation Edition*, that:

> For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. … The geometric mean is more appropriate for reporting past performance, since it represents the compound average return. (p. 71)

One does not have to get deep into finance theory to see why the arithmetic mean is more consistent with the facts of this case. The FPSC is not setting a constant return that FPL is guaranteed to earn over a long period. Rather, the exercise is to set an expected return based on test year data. In the real world, FPL's yearly return will be volatile, depending on many economic and weather factors, and investors do not expect to earn the same return each year.

Q. What does this imply with respect to the conclusions of Dr. Woolridge's CAPM analysis?

A. As noted earlier, Dr. Woolridge based his market equity risk premium in part on a paper summarizing the risk premiums reported in various academic studies. Apart from the problems associated with the individual studies noted earlier, as indicated on Exhibit __ (JRW-8), page 3, almost one-half of the risk premiums reported by Dr. Woolridge were based on geometric means. For a variable series, such as stock returns, the geometric average will always be less than the arithmetic average. Accordingly, Dr. Woolridge's reference to studies based on geometric average rates of return provides yet another element of downward bias.

Similarly, this same downward bias is also reflected in the market return data Dr. Woolridge referenced from the *Survey of Professional Forecasters*, which is a *geometric* average return over the next 10 years.

Q. Do the 5-year Treasury bills rates referenced by Mr. Baudino (p. 37) provide an appropriate basis to estimate the cost of equity using the CAPM?

A. No. Common equity is a perpetuity and as a result, any application of the CAPM to estimate the return that investors require must be predicated on their expectations for the firm's long-term risks and prospects. This does not mean that every investor will buy and hold a particular common stock into perpetuity. Rather, it recognizes that even an investor with a relatively short holding period will consider the long-term, because of its influence on the price that he or she ultimately receives from the stock when it is sold. This is also the basic assumption underpinning the DCF model, which in theory considers the present value of all future dividends expected to be received by a share of stock.

Shannon P. Pratt, a leading authority in business valuation and cost of capital, recognized in "Cost of Capital, Estimation and Applications," (1998) that the cost of equity is a long-term cost of capital and that the appropriate instrument to use in applying the CAPM is a long-term bond:

> The consensus of financial analysts today is to use the 20-year U.S. Treasury yield to maturity as of the effective data of valuation for the following reasons:
>
> - It most closely matches the often-assumed perpetual lifetime horizon of an equity investment.
> - The longest-term yields to maturity fluctuate considerably less that short-term rates and thus are less likely to introduce unwarranted short-term distortions into the actual cost of capital.
> - People generally are willing to recognize and accept the fact that the maturity risk is impounded into this base, or otherwise risk-free rate.
> - It matches the longest-term bond over which the equity risk premium in measured in the Ibbotson Associates data series. p. 60

Similarly, in applying the CAPM Ibbotson Associates recognized that the cost of equity is a long-term cost of capital and the appropriate interest rate to use is a long-term bond yield:

> The horizon of the chosen Treasury security should match the horizon of whatever is being valued. ... Note that the horizon is a function of the investment, not the investor. If an investor plans to hold a stock in

a company for only five years, the yield on a five-year Treasury note would not be appropriate since the company will continue to exist beyond those five years.[14]

Accordingly, proper application of the CAPM should focus on long-term government bonds – not the 5-year Treasury notes reference by Mr. Baudino – in estimating the cost of equity for an electric utility.

Q. **Do these observations also apply to the risk-free rate used by Dr. Woolridge?**

A. Yes. Dr. Woolridge wrongly asserts (p. 29), that "the yield on 10-year Treasury bonds has replaced the yield on 30-year Treasury bonds as the benchmark long-term Treasury rate." In fact, however, this is simply not the case, with both Mr. Kahal and myself referencing the yields on 20-year Treasury bonds, not the 10-year notes relied on by Dr. Woolridge.[15] These medium-term securities are subject to the same criticisms outlined above with respect to Mr. Baudino's 5-year notes, and provide another example of the downward bias that infects Dr. Woolridge's analyses and conclusions.

Q. **Do Intervenors offer any meaningful criticisms of your risk premium approaches based on allowed ROEs and realized returns for electric utilities?**

A. No. Dr. Woolridge's major criticism is that these studies are based on historical information. While I would agree that the forward-looking CAPM study contained in Document WEA-9 is apt to provide a more direct reflection of future expectations, reference to allowed rates of return and realized rates of return for electric utilities

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[14] Ibbotson Associates, *2003 Yearbook* (Valuation Edition) at 53.

[15] Dr. Woolridge also incorrectly asserts (p. 63) that I used a 30-year Treasury rate , which is clearly not accurate.

provides a direct approach to estimate the cost of equity that does not require extrapolation from a market benchmark. Such approaches have been widely referenced in regulatory proceedings. Moreover, this "criticism" is ironic considering that Dr. Woolridge's CAPM was predicated almost exclusively on historical data. Further, Dr. Woolridge's reference to "survivorship bias" and the "peso problem" are not relevant, given that my studies focused directly on electric utilities and not on the S&P 500 Index.

Second, Dr. Woolridge wrongly claims that reference to allowed rates of return for electric utilities involves "circular reasoning." Similarly, Mr. Baudino (p. 53) mistakenly asserts that, by considering the risk premiums implied by past authorized returns, the FPSC would somehow lose its ability to evaluate evidence in this proceeding. In fact, however, the cost of equity findings reflected in Document WEA-6 and the FPSC's actions in this proceeding are entirely independent. Authorized rates of return presumably represent regulators' best assessment of investors' required rate of return at the time of the decision. While this is a valid approach that warrants consideration in the FPSC's deliberations, there is no "circularity" between the two. Under Dr. Woolridge's paradigm, it would be just as valid to argue that the use of projected earnings growth rates is "circular," since these are presumably impacted by expectations of regulatory actions. The fact that no credible analyst would make such an argument illustrates the fallacy of Dr. Woolridge's criticism here.

Similarly, Mr. Kahal's criticisms (p. 37-38) of the allowed rates of return used in this approach are without merit. First, he is incorrect to allege that the information regarding average allowed rates of return in each year is unreliable simply because every item of possible interest in each rate case is not also presented in my schedule. The allowed rates of returns are taken from a recognized and widely-used publication from a firm with a long history of accumulating and reporting the results of state regulatory commission decisions. Mr. Kahal and Mr. Baudino (p. 53) question the potential that authorized ROEs may consider "adjustment factors," such as flotation costs. But such criticisms miss the point. Under this approach, it is not necessary to examine the actual tools and techniques relied on by regulators to set allowed rates of return. Rather, what matters is that, after reasoned consideration of the evidence presented by all participants to a rate proceeding, regulators make an informed determination of a fair rate of return at the time they issue their decision. This determination is embodied in the authorized rates of return on equity that I used to apply the risk premium approach.

With respect to his remaining argument, Mr. Kahal is wrong to claim (p. 38) that the inverse relationship between equity risk premiums and interest rates is due to "behavior of the regulatory process" rather than "the requirements of financial markets." In fact, the inverse relationship between equity risk premiums and interest rates has been widely reported in the financial literature. As noted in *Regulatory Finance: Utilities' Cost of Capital*:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992), Arelton, Chambers, and Lakonishok (1983), McShane (1993) and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose. (p. 291)

In conclusion, my risk premium analyses based on authorized and realized rates of return for electric utilities represent sound approaches to estimating investors' requirements and Intervenors criticisms of these methods are unfounded.

OTHER ISSUES

Q. Does Dr. Woolridge's discussion of market-to-book ratios (pp. 14 & 49) provide any meaningful basis on which to evaluate the cost of equity for FPL?

A. No. The argument that regulators should set a required rate of return to produce a market-to-book value of approximately 1.0 is fallacious. As noted in *Regulatory Finance: Utilities Cost of Capital*:

> The stock price is set by the market, not by regulators. The M/B ratio is the end result of regulation, and not its starting point. The view that regulation should set an allowed rate of return so as to produce a M/B of 1.0, presumes that investors are masochistic. They commit capital to a utility with a M/B in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. This is not a realistic or accurate view of regulation. (p. 265)

Indeed, while Dr. Woolridge reports an average return on equity of 11.0% on common equity for the firms in the proxy group (p. 49), he suggests that regulators should allow them to earn no more than 8.8%. With market-to-book ratios above 1.0 times, Dr. Woolridge apparently believes that, unless book value grows rapidly, regulators should establish equity returns that will cause share prices to fall.

Within the paradigm of DCF theory, a drop in stock prices means negative growth, and if investors expect negative growth then this is the relevant "*g*" to substitute in the constant growth DCF model. In turn, a negative growth rate implies a DCF cost of equity for utilities less than their dividend yields. This, of course, is truly a nonsensical result, and a manifestation of the failings of Dr. Woolridge's arguments.

Q. Have regulators previously recognized the fallacy of relying on market-to-book ratios in evaluating cost of equity estimates?

A. Yes. For example, the Presiding Judge in *Orange & Rockland* concluded, and the FERC affirmed that:

> The presumption that a market-to-book ratio greater than 1.0 will destroy the efficacy of the DCF formula disregards the realities of the market place principally because the market-to-book ratio is rarely equal to 1.0.[16]

The Initial Decision found that there was no support in Commission precedent for the use of market-to-book ratios to adjust market derived cost of equity estimates based on the DCF model and concluded that such arguments were to be treated as "academic rhetoric" unworthy of consideration.

Q. Does Mr. Kahal accurately characterize the results of your analyses?

A. No. Mr. Kahal wrongly asserts (p. 32) that the results of my analyses actually support a return on equity of only 10.0%. However, Mr. Kahal arrives at his conclusion only after discarding the results of my risk premium analyses that incorporate expectations of higher interest rates and mechanically averaging risk premium and DCF cost of equity estimates. As noted earlier, in applying the risk premium approach, it is entirely appropriate to consider widely-anticipated increases in long-term interest

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[16] *Orange & Rockland Utilities, Inc.*, Initial Decision, 40 FERC ¶ 63,053, 1987 WL 118,352 (F.E.R.C.).

rates over the period when rates establishing in this proceeding will be in effect. Mr. Kahal's suggestion that the results of alternative quantitative methods should simply be averaged together, without the benefit of informed judgment, is similarly flawed. As discussed in detail in my direct testimony and earlier here, there is considerable evidence to suggest that DCF cost of equity estimates for electric utilities are downward-biased and should be accorded less weight. Mr. Kahal's interpretation ignores this reality and understates investors' required return. Finally, Mr. Kahal ignores the evidence presented in my direct testimony concerning the potential challenges facing FPL and the need to support FPL's ability to attract capital under adverse circumstances, which justify a return for FPL from the upper half of the proxy group results.

Q. Do you agree with Ms. Dismukes that Dr. Woolridge's cost of capital should be used as the basis for the costs charged to FPL by FiberNet?

A. No. First, Dr. Woolridge's cost of capital is not an acceptable estimate of the cost of capital for FPL for the reasons I have discussed above. Moreover, the services being priced are telecommunications services, not electric utility services. The cost of capital for telecommunications services is generally regarded as higher than for electric utility services, particularly for competitive local exchange companies such as FiberNet. For example, the FCC has been using a before-tax 11.25% benchmark rate of return for regulatory purposes since 1990.[17] I was a witness in the FCC case that originally established the before-tax 11.25% return and have participated in subsequent proceedings at the FCC to review the prescribed rate of return, which has been unchanged and remains effective for purposes such as universal service fund payments in Florida and elsewhere in the United States. Another benchmark for the return appropriate for telecommunications is the unbundled network elements cost of capital found by the FPSC. For example, in Order PSC-03-0058-FOF-TP issued on January 8, 2003, the FPSC found a cost of capital for Sprint unbundled network elements in Florida of 9.86%.[18] As shown on Document WEA-13, with the appropriate gross-up for taxes, the Sprint rate is 14.19% and the FCC rate is 15.89%. This gross-up is necessary because FiberNet does not charge separately for income tax expense. Accordingly, when either of these benchmark costs of capital approved by regulatory authorities is grossed up for taxes, the cost exceeds the 13.97% used by FiberNet in its billings to FPL. Therefore, the cost of capital used in FiberNet's billings for telecommunications services to FPL is reasonable.

Q. Did Intervenors recognize the need to consider flotation costs in setting a fair rate of return?

A. While Mr. Kahal included a 10 basis-point upward adjustment for flotation costs, Mr. Baudino ignored this component of a fair rate of return. Meanwhile, Dr. Woolridge

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[17] *In the Matter of Represcribing the Authorized Rate of Return for Interstate Services of Local Exchange Carriers (*CC Docket No. 89-624), Released December 7, 1990; Adopted September 19, 1990: As Corrected December 21, 1990). While the FCC did not specify the component costs and capital structure, it did suggest in footnote 311: "The implied return on equity is 13.2%. That is, a company with an embedded cost of debt of 8.8% and a capital structure of 44.2% debt/55.8% equity that earned 11.25% overall return on capital would have a return on equity of 13.2%."

[18] In re: Investigation into pricing of unbundled network elements (Sprint/Verizon track).

argued (p. 55) that flotation costs "are one-time expenses which are incurred when a Company sells additional stock," and should only be included on a prospective basis for new equity issues.

Q. Is Dr. Woolridge's position consistent with financial realities and the views of other practitioners?

A. No. The need for a flotation cost adjustment to compensate for past equity issues is recognized in the financial literature. In a *Public Utilities Fortnightly* article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[19] Similarly, *Regulatory Finance: Utilities' Cost of Capital* contains the following discussion:

> Another controversy is whether the underpricing allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation

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[19] Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly,* May, 2, 1985.

costs, which is an unlikely assumption, and certainly not applicable to most utilities. ... The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered. (p. 175)

Q. Can you provide a simple numerical example illustrating why a flotation cost adjustment is necessary to account for past flotation costs?

A. Yes. The following example demonstrates that investors will not have the opportunity to earn their required rate of return (*i.e.*, dividend yield plus expected growth) unless an allowance for past flotation costs is included in the allowed rate of return on equity. Assume a utility sells $10 worth of common stock at the beginning of year 1. If the utility incurs flotation costs of $0.48 (5% of the net proceeds), then only $9.52 is available to invest in rate base. Assume that common shareholders' required rate of return is 11.5%, the expected dividend in year 1 is $0.50 (*i.e.*, a dividend yield of 5%), and that growth is expected to be 6.5% annually. As developed below, if the allowed rate of return on common equity is only equal to the utility's 11.5% "bare bones" cost of equity, common stockholders will not earn their required rate of return on their $10 investment, since growth will really only be 6.25%, instead of 6.5%:

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$10.00	1.050	11.50%	$ 1.09	$ 0.50	45.7%
2	$ 9.52	$ 0.59	$10.11	$10.62	1.050	11.50%	$ 1.16	$ 0.53	45.7%
3	$ 9.52	$ 0.63	$10.75	$11.29	1.050	11.50%	$ 1.24	$ 0.56	45.7%
Growth			6.25%	6.25%			6.25%	6.25%	

The reason that investors never really earn 11.5% on their investment in the above example is that the $0.48 in flotation costs initially incurred to raise the common stock is not treated like debt issuance costs (*i.e.*, amortized into interest expense and therefore increasing the embedded cost of debt), nor is it included as an asset in rate base.

Q. **Can you illustrate how the flotation cost adjustment allows investors to be fully compensated for the impact of past issuance costs?**

A. Yes. As discussed in my direct testimony, one method for calculating the flotation cost adjustment is to multiply the dividend yield by a flotation cost percentage. Thus, with a 5% dividend yield and a 5% flotation cost percentage, the flotation cost adjustment in the above example would be approximately 25 basis points. As shown below, by allowing a rate of return on common equity of 11.75% (an 11.5% cost of equity plus a 25 basis point flotation cost adjustment), investors earn their 11.5% required rate of return, since actual growth is now equal to 6.5%:

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$10.00	1.050	11.75%	$ 1.12	$ 0.50	44.7%
2	$ 9.52	$ 0.62	$10.14	$10.65	1.050	11.75%	$ 1.19	$ 0.53	44.7%
3	$ 9.52	$ 0.66	$10.80	$11.34	1.050	11.75%	$ 1.27	$ 0.57	44.7%
Growth			**6.50%**	**6.50%**			**6.50%**	**6.50%**	

The only way for investors to be fully compensated for issuance costs is to include an ongoing adjustment to account for past flotation costs when setting the return on common equity. This is the case regardless of whether or not the utility is expected to issue additional shares of common stock in the future.

Q. Dr. Woolridge (p. 55) and Mr. Kahal (p. 40, lines 6-15) suggest that the FPSC adopt an accounting treatment for the recovery of flotation costs. Are there any concerns that the Commission should be aware of?

A. Yes. While expensing would be one way of going forward, it would ignore the costs already incurred in connection with past stock issuances. The only practicable means available to ensure that FPL has the opportunity to earn investors' cost of capital is to include an allowance for past flotation costs in arriving at the fair rate of return. This is consistent with treatment of flotation costs at the FPSC in past proceedings.

Q. Do you agree with Mr. Kahal's assessment of a reasonable flotation cost percentage?

A. No. As noted in my direct testimony, a review of the finance literature indicated that the flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, not the 3% advocated by Mr. Kahal. Moreover, the purpose of the flotation cost adjustment is not to amortize flotation costs over a predetermined schedule. While this is one approach to cost recovery that has been adopted for the financial reporting of debt issuance costs, an equity flotation cost adjustment recognizes that investors are unable to earn a rate of return on the portion of their capital paid out as flotation costs on an ongoing basis.

Q. Do you agree with Intervenors that changes in dividend taxation enacted in 2003 have led to a significant decline in investors' required rate of return on equity?

A. No. While dividend taxation is certainly one factor that may be considered by investors, the impact of changes in dividend taxation on the cost of equity for FPL is unclear. First, the important role that pension funds and tax deferred accounts play in the capital markets dilutes any effect that tax rate changes might have on investors' required rate of return. This is because the reduction in the taxation of dividends has no impact on the returns for tax-free investors. Moreover, as Mr. Kahal noted (p. 8), the current stock prices that formed the basis of my DCF analysis and forward-looking CAPM approach (Document WEA-9), already incorporate any effects of changes in tax policies. Indeed, Mr. Baudino observed (p. 9) that:

> The stock prices that I use in my cost of equity analyses fully incorporate the effects of the change in tax rates and on the expected returns for utilities.

Finally, while Intervenors' claim that changes in dividend taxation suggest that the equity risk premium has declined relative to those indicated by historical studies, this ignores other significant factors that influence required returns. In particular, as a result of events during the past several years, investors' risk perceptions for electric utilities shifted sharply upward, which would more than offset any decline in the equity risk premium due to changes in dividend taxation.

Q. Have Intervenors' considered the impact of their ROE recommendations on FPL's financial integrity and ability to attract capital?

A. No. As explained and documented in my direct testimony, in light of challenges in the electric utility industry, investors have refocused attention on regulatory policy. Mr. Baudino recognized the ongoing risks that investors associate with the electric utility industry (pp. 12-13), citing "continued erosion in financial credit measures, increasing business risk, aggressive financial policies, and uncertainty regarding funding of accelerating capital programs."

Investors recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity and it is critical to assure investors' confidence in a balanced approach if financial flexibility and access to capital is to be maintained. As Mr. Baudino specifically noted in his testimony (p. 14):

> S&P currently assigns a negative outlook to FPL Group and its subsidiaries due mostly to pending resolution of regulatory issues, such as the current rate proceeding.

However, as documented earlier, Intervenors' ROE recommendations are downward-biased and fall far below investors required rate of return. As a result, their recommendations would compromise investor confidence, as well as FPL's ability to meet the capital requirements and challenges associated with providing electric service in Florida.

Q. Do customers also benefit by enhancing the utility's financial flexibility?

A. Yes. 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 electric service. 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.

Given the social and economic importance of reliable electricity service in South Florida, which is one of the fastest growing areas in the nation, it is imperative that the FPSC continue to support recovery of reasonable capital costs such that FPL may invest in its system and maintain reliable and economical service to all customers. To his credit, Mr. Kahal specifically noted (p. 39) that "[p]rojections of increases in capital costs," would warrant an expansion of the ROE range. Financial flexibility is particularly crucial in today's electric power industry, where changes can come at a blistering pace or, literally, fall from the sky. Recent years are not the only time electric utilities have experienced changes that were both dramatic and unanticipated. In the early 1970's, electric utilities were generally viewed as the paragon of stability and few, if any observers foresaw a storm looming on the horizon. This favored position evaporated quickly for many electric utilities as the oil embargo, sky-rocketing natural gas prices, and federal legislation mandating conversion from natural gas to alternative fuels swept them from financial strength to crisis in a few short years. To continue to meet potential challenges successfully and economically, it is crucial that FPL receive adequate support for its credit standing.

CAPITAL STRUCTURE

Q. Do you agree with Intervenors that FPL's requested equity ratio results in a level of investment risk that is below that of the proxy group of utilities?

A. No. Dr. Woolridge argues that FPL's lower financial risk "allows for a lower allowed return (p. 11), while Mr. Kahal suggests (p. 13) that the Commission should "take into account the Company's very heavy equity ratio in setting the Company's authorized ROE." However, as I explained in detail in my direct testimony, FPL's equity ratio alone is not an indicia of investment risk. First, as Mr. Kahal granted (p. 13, lines 6-7), any evaluation of FPL's capital structure must consider the impact of off-balance sheet debt obligations. Second, a comparison of bond ratings, which provide a widely-referenced and objective guide to overall investment risks, indicates that investors consider FPL's risks to be comparable to those of the utilities in the proxy group. Moreover, FPL's capital structure reflects the Company's efforts to maintain its financial flexibility and preserve its ability to meet growth and respond to potential uncertainties, and Mr. Kahal agreed with me (p. 12) that the electric utility industry is moving towards higher equity ratios. Finally, the importance of maintaining a relatively conservative financial posture is reinforced by S&P's decision to maintain a "negative" outlook on FPL's ratings, indicating the potential for further declines in the Company's credit standing. Absent its relatively conservative 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.

Q. Do Dr. Woolridge or Mr. Kahal propose any specific adjustment to FPL's ROE related to the company's capital structure?

A. No. Ironically, while Dr. Woolridge criticizes me (p. 53-54) for "the lack of a financial risk adjustment," he concludes (pp. 47-48) that "I am not making any explicit downward adjustments to my equity cost rate to reflect the lower financial risk." Similarly, Mr. Kahal elected not to recommend any modification to FPL's capital structure or a specific adjustment to his recommended ROE.

Q. Is there any merit to Dr. Woolridge's criticism of your capital structure comparison (Document WEA-12)?

A. No. Dr. Woolridge wrongly asserts (p. 52) that a comparison of FPL's capital structure with the capitalization maintained by other electric utility operating companies is somehow "apples and oranges". In fact, however, reference to other electric utility operating companies provides an "apples to apples" basis for evaluating FPL's capital structure relative to similarly situated companies. In contrast to Dr. Woolridge's erroneous conclusions regarding FPL's capital structure and overall investment risks, my purpose was not to use this comparison to make inferences regarding FPL's relative investment risks vis-à-vis the proxy group, as Dr. Woolridge suggests. As discussed above and in my direct testimony, I looked to credit ratings for an objective measure of overall investment risk perceived by investors. However, in evaluating the reasonableness of FPL's capital structure, these operating electric utilities provide a useful benchmark as to the range of capitalization ratios maintained in the industry.

Q. Is there any justification for Mr. Kollen's recommendation to set FPL's equity ratio at the midpoint of S&P's benchmark range for a single-A rating?

A. No. First, investors and the rating agencies do not consider capital structure in isolation. Rather, an appropriate capitalization reflects the mix of capital sources required to accommodate the utility's business risks and maintain access to capital and financial integrity. As I noted earlier and in my direct testimony, despite its conservative financial policies, S&P retains a negative outlook on FPL, which indicates the potential for further degradation in the Company's credit standing going forward. If FPL were to lower its equity ratio to the level recommended by Mr. Kollen, the outcome would be swift and predictable – the Company's credit ratings would plunge along with investor confidence. Similarly, adopting such an extreme recommendation would send an ominous signal to investors that would undoubtedly cause them to reevaluate the risks of FPL and other Florida utilities and ultimately lead to significantly higher capital costs. While Mr. Kollen argues that his capital structure recommendation would result in a reduction to FPL's revenue requirements of $39.3 million, his assessment is short-sighted and fails to consider the damaging consequences that higher capital costs and weakened financial flexibility would have on customers over the longer-term.

Q. Does this conclude your rebuttal testimony?

A. Yes.

ERRATA SHEET

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

PAGE #	LINE #	CHANGE
4	ftnt 3	change date of report from "April 18, 2005" to "June 20, 2005"

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF MORAY P. DEWHURST

DOCKET NOS. 050045-EI, 050188-EI

JULY 28, 2005

Q. Please state your name and business address.

A. My name is Moray P. Dewhurst. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408-0420.

Q. Did you previously submit direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I will rebut assertions made by various witnesses on behalf of the Florida Office of Public Counsel (OPC), Federal Executive Agencies (FEA), AARP, Commercial Group, Florida Retail Federation (FRF) and the South Florida Hospital and Healthcare Association (SFHHA). My rebuttal testimony will focus on Florida Power & Light's (FPL or Company) appropriate ROE, the Company's request for a 50 basis point performance incentive, the appropriateness of FPL's capital structure, the Company's request for an additional base rate increase for Turkey Point 5, the Company's request for an increase in the storm accrual, and the need for the Company to maintain D&O insurance.

RETURN ON EQUITY

Q. Do you agree with the return on equity recommendations made by Dr. Woolridge, Mr. Baudino or Mr. Kahal?

A. No. I will defer discussion of the analytical flaws in their respective approaches to Dr. Avera. My rebuttal testimony discusses the reasonableness of the overall level of return on equity recommended by these witnesses and the general impact on the Company's financial strength, were the Commission to adopt any of their recommendations.

Q. What do you think the Commission's objectives should be in establishing the Company's authorized return on equity?

A. The return on equity should be set at a level that, if achieved by the Company, will induce the level of investment needed to provide reliable electric service and accommodate system growth at the lowest reasonable cost and fairly compensate equity holders for the utilization of their capital.

Q. In your opinion, if the Commission were to adopt the return on equity recommendations presented by Dr. Woolridge, Mr. Baudino or Mr. Kahal, would those objectives be met?

A. No. The Company must compete for investor capital by offering a reasonable return that is at least as large as the returns available on investments with similar risk profiles. The proposed allowed returns on equity suggested by Dr. Woolridge, Mr. Baudino and Mr. Kahal would be substantially below the returns available to investors on comparable investments and insufficient to maintain access to capital markets at reasonable prices. Both Dr. Woolridge's recommendation for an 8.8% return on equity and Mr. Baudino's recommendation for an 8.7% return on equity would result in the Company receiving the lowest authorized return out of the 700+ major electric, gas or telecommunications proceedings since at least 1990 (the most recent date summarized case data are available for comparison). Even Mr. Kahal's 9.5% recommended mid-point allowed return on equity is below the authorized return on equity for every major electric, gas, and telecommunications proceeding since 1990 except for one base rate proceeding for Jersey Power & Light (Final Order for Docket No. ER02080506, issued May 17, 2004) in which its regulator provided for a 9.5% return on equity. However, significantly, that return involved only the distribution assets of Jersey Power & Light, and reflected a 25 basis point penalty as a "regulatory incentive mechanism" until such time as "the Company provides sufficient evidence to the Board that they have made the necessary improvements required to maintain system reliability". It is quite clear, therefore, that the intervenors' ROE recommendations would <u>not</u> represent a fair and reasonable return opportunity for investors.

Q. **What would be the likely consequences for FPL's financial position if the intervenors' ROE recommendations were adopted?**

A. There would be several significant and adverse consequences to FPL's financial position, which would hurt customers' interests. The most immediate effect would be a significant reduction in operating cash flow and free cash flow. The three percentage point difference between FPL's recommended ROE (excluding the 50 basis point performance incentive) and the recommendations of Dr. Woolridge and Mr. Baudino translates to nearly a $200 million reduction in annual cash flow. For reference, this is more than 10% of projected 2006 operating cash flow for the entire business. This would increase the dependence of the business on access to external funding and would obviously exacerbate the challenge of meeting capital expenditure requirements.

A second effect would likely be dramatically reduced investor confidence in the Florida regulatory environment. Such a dramatic shift between a regulatory framework that promoted efficiency in operations and provided some measure of regulatory certainty to one that took a company that was operationally among the very best in the industry, and "rewarded it" by giving it the lowest return on equity awarded among any major utility since 1990 would seriously reduce investor confidence in the Florida regulatory environment and increase investor perceptions of regulatory risk with respect to other issues. Clearly, this would serve to *increase* the future cost of capital.

Third, FPL's credit standing would be weakened and credit ratings would likely be lowered. Credit spreads would widen, resulting in immediate losses to debtholders and decreased access to new capital, as well as increases in interest costs. Short-term credit capacity would be substantially decreased, significantly limiting the Company's ability to support the fuel hedging program it manages for the customer's benefit, reducing flexibility in the event of unexpected shocks, and raising costs.

Fourth, there would be an immediate loss in equity value as well as confidence, a related consequence of which would likely be pressure for an increase in dividends, because the shareholder trade-off between current return (dividend) and future return (capital gain) necessarily would be shifted towards the former. Of course, any increase in dividends needed to maintain equity investor confidence would obviously further exacerbate the cash flow shortfall.

Ultimately, all these effects would be very detrimental to long-run operating performance, undermining FPL's efforts to support its extensive capital building program while maintaining or improving reliability and customer service. The result would not be in customers' long-run interests.

Q. **Intervenors, as part of ROE testimony, have cited FPL's strong financial position as reason why FPL has lower risk and should have a lower ROE. Do you agree with this characterization?**

A. No. These assertions are circular in that a lower ROE would weaken the Company's financial position, thus undermining the very basis of such contentions. A strong financial position should be viewed as an asset rather than a liability. A strong financial position allows the Company to maintain the flexibility to raise capital when needed to meet our service obligations.

This position also provides security that provides the ability to absorb unexpected financial shocks. While our current financial position is strong, this is not a given. Adequate allowed return on equity and an appropriate equity ratio underpin our financial strength. Weakening in any of these areas would clearly be perceived by investors as a decline in our overall financial strength. A decline in financial strength introduces greater risk. In turn, investors will require a greater return on their invested dollar.

ROE PERFORMANCE INCENTIVE

Q. **Mr. Larkin and Ms. Brown assert that FPL's requested ROE performance incentive is based solely on past performance and, therefore, should be rejected. Do you agree with their assertions?**

A. No, I do not. FPL is not requesting a performance incentive based solely on past performance, although we certainly agree that past performance is one factor that the PSC can look to as an indicator of whether or not an incentive award may be justified. FPL's request is based in large part on its ***current*** operating and performance statistics. As described in the direct testimonies of others in this case, the Company is ***currently*** operating at levels significantly above its industry peer group in the areas of reliable service, customer service and overall cost, providing customers with past, present, and future benefits. Nevertheless, such achievements are not accomplished overnight; they reflect a steady record of improvement over many years. To that end, therefore, past performance cannot simply be ignored. A performance incentive that shifts the allowed ROE range up 50 basis points would serve as a positive incentive for the Company to continue its excellent performance as well as 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.

Clearly, both past and present performance is directly relevant in establishing a reasonable rate of return. A system that does not distinguish between superior and mediocre performance, over time will not tend to promote superior performance. Conversely, a system that recognizes superior performance will tend to improve performance and lower cost over the long-term.

Q. **Do you agree with Mr. Larkin's and Mr. Kollen's contention that the performance incentive is, in the words of Mr. Kollen, "the quintessence of improper retroactive ratemaking" and as Mr. Larkin states that the Commission, "cannot look to past performance and use that performance to enhance or increase future rates"?**

A. No. Mr. Larkin and Mr. Kollen appear to be suggesting that the Commission, as a matter of law, cannot approve FPL's requested ROE performance incentive. Regardless of what Mr. Kollen means by "retroactive ratemaking" and Mr. Larkin's frame of reference, my understanding is that the Commission has broad ratemaking authority granted by the legislature in setting just and reasonable rates, including the authority to adjust a company's

ROE in recognition of good performance. The Commission has used this authority on several separate occasions. In Order No. PSC-02-0787-FOF-EI, Docket 010949-EI, the Commission provided a 25 basis point ROE incentive to Gulf Power stating:

"We find that Gulf's past performance has been superior and we expect that level of performance to continue into the future. In recognition of this, we find that Gulf deserves to have 25 basis points added to the mid-point ROE of 11.75%. Thus, a 12% ROE shall be used for all regulatory purposes, including, for example, implementing the cost recovery clauses and allowances for funds used during construction."

In addition to providing a reward for good performance, the Commission has also used its authority to impose an ROE penalty for poor performance. In Order No. 23573, Docket 891345-EI, the Commission imposed a two year 50 basis point penalty on Gulf's ROE as a result of criminal and unethical conduct of one of its Vice Presidents. In Order Nos. 10557-EI and 9628-EI the Commission granted a 10 basis point adjustment to Gulf Power to reward Gulf's innovative efforts in the area of energy conservation and to send a message to other utilities to promote conservation.

Q. **Have Commissions in other jurisdictions employed similar performance incentive plans?**

A. Yes. FPL's request for a ROE performance incentive is not predicated on actions in other jurisdictions, but rather on this Commission's authority under

Florida law. Nevertheless, while we have not attempted to conduct a comprehensive search of ROE-based incentive plans in other jurisdictions, we have identified other instances in which retail regulators have provided recognition of good performance in the form of ROE adjustments such as FPL has requested in this proceeding. These instances include:

> West Penn Power Co: Docket No. R00942986
> *Pa. Public Utility Commission: Order Issued Dec. 15, 1994*
>
> The commission decided to add .25% to the company's allowed ROE "to compensate the company for its management performance," recognizing that the company "has promoted and accomplished cost efficiencies in several operations aspects."
>
> US West Communications, Inc: Docket No. RPU-93-9
> *Iowa Utilities Board: Order Issued June 17, 1994*
>
> Despite the ultimate finding which required a revenue decrease, the Iowa Utilities Board awarded the company a "management efficiency award of 75 basis points added to the return on equity." It claimed that the award was based upon performance related to the company's response to a flood, the merger of operating companies, and the reduction in the number of employees.

In addition to these specific circumstances, there have been other instances where a utility was awarded an authorized return on equity that was at the upper end of the range of reasonable returns for the purpose of rewarding the Company for its management performance.

Q. **Do you agree with Mr. Larkin's and Mr. Dismukes' contentions that the Company has already been rewarded through the revenue sharing mechanism as a result of increasing revenues and that the Company benefited by approximately $113 million dollars due to refunds of revenues?**

A. No. Mr. Larkin either misunderstands or has mischaracterized the revenue sharing agreement. The revenue sharing plans approved in 1999 and 2002 provided customers with two substantial base rate reductions totaling $600 million and will have resulted in more than $3.6 billion in savings to customers by the end of this year. In exchange for the ability to enhance its earnings through efficient management, the Company gave up the opportunity for additional earnings potential from unanticipated positive revenue growth - earnings potential that would have been available to it under traditional ratemaking. Revenues above certain thresholds were refunded to customers, thus lowering their effective cost of electricity even further. These refunds amounted to approximately $226 million of additional customer savings during the terms of the two agreements - revenues that would otherwise have resulted in higher earnings for the Company.

Far from benefiting from the revenue sharing refund provision, FPL was disadvantaged by it. FPL was willing to agree to this provision only because of other provisions in the agreements – namely the absence of an authorized range for return on equity and the incentive therefore to manage the business for long-run efficiency. In the present circumstances FPL does not enjoy the prospect of operating without an ROE cap and it is as a substitute for the incentives built into the prior agreements that we are proposing the ROE performance incentive.

Furthermore, what Mr. Larkin's and Mr. Dismukes' positions fail to acknowledge is that many of the efficiencies and productivity improvements will provide savings and value to customers well into the future. Over the long-term, the customer benefits from an operation that can deliver efficient electrical service at a cost that is lower than it otherwise would have been. The 50 basis point performance incentive has been proposed to promote and encourage ongoing high levels of performance.

Q. Is it relevant whether or not the Company has realized any benefits under prior revenue sharing agreements?

A. No. Whether or not the Company realizes a benefit through productivity efficiencies achieved during the terms of the revenue sharing plans is not relevant for purposes of determining whether to grant the Company's ROE performance incentive request. FPL's request in the present case is based on its recent and current levels of performance, which translate into direct benefits to customers, and the prospect of motivating continued efforts to improve performance and maintain or improve the Company's relative position. As I stated in my direct testimony, FPL does not dispute that traditional ratemaking regulation provides strong incentives for *adequate* performance. The policy question that we believe the Commission should consider is how to motivate sustained efforts to move beyond "good" or "adequate" and deliver the superior levels of performance that FPL has been able to achieve.

Q. Does the existing regulatory structure that provides for an authorized range of return consisting of a band of ± 100 basis points provide an effective performance incentive as argued by Mr. Larkin?

A. No. The ± 100 basis point band reflects acknowledgement of an inherent amount of variability within a utility's earnings through the normal business cycle, and allows the regulator some flexibility in determining whether to adjust rates, thereby promoting regulatory efficiency. As a practical matter, a 100 basis point band above the midpoint provides very little incentive for superior performance, though it may promote some "fine tuning" of the cost structure. It is relevant to note that normal weather variability will cause swings in excess of ± 80 basis points of ROE. To the extent it does provide any incentive it is, from a policy perspective, a relatively poor one for at least two reasons. First, because it is a normal part of the traditional ratemaking process it is not contingent upon a demonstration of superior performance; therefore, it does not distinguish between average performers and superior performers – it is equally available to both, and therefore does nothing to promote superior performance. Second, perversely, it may actually serve as a disincentive to superior performance, since a company performing well on the cost dimension (operating at or close to the top of its allowed range), or one that has just made some improvement, has no incentive to improve further. As my earlier testimony notes, there are strong incentives built into the traditional ratemaking framework promoting good, average, prudential performance. What is lacking (relative to the incentives inherent in unregulated markets) is the positive incentive to seek to be well above average. Yet the long run benefit to the customer from promoting superior performance can be very large. The ROE performance incentive, awarded at the discretion of the Commission on the basis of superior overall performance, taking into account cost, reliability and customer service, can serve to provide this incentive.

Q. Mr. Larkin argues that FPL's declining cost per customer is due to customer growth rather than particular steps taken by the utility. Do you agree with his statement?

A. No. While there are modest scale effects in the industry, these are not the principal driver of FPL's excellent unit cost position. Mr. Landon's testimony clearly shows that FPL has a lower cost per customer when compared to other large utilities that enjoy similar scale. Mr. Larkin contends that with the exception of fuel, the cost of providing electric service is essentially fixed, although he provides no data, studies or analysis to support his position. This simply is not the case. Indeed, today in many parts of its service territory FPL faces structurally increasing unit costs to serve new customers. For example, redevelopment in heavily urbanized areas of Miami-Dade and Broward counties necessitate new facilities installed at much higher cost than embedded rates. These challenges are not faced by many utilities with lower growth rates, yet FPL's unit cost performance is superior in spite of the additional handicap.

Q. How are customers benefited by the Commission providing an ROE performance incentive?

A. There is no doubt that superior performance produces customer benefits in the form of reliable electric service at lower costs. However, the question that intervenor witnesses all seem to raise is whether there is any correlation between superior performance and the performance incentive requested by the Company. Certainly this is a matter for the Commission's judgment. However, I would note that the Commission has previously endorsed the principle of providing incentives, has approved rate agreements incorporating incentive mechanisms, and has utilized an ROE performance incentive such as FPL is proposing here. Presumably, therefore, the Commission has found that there is such a correlation. Ultimately, the Commission must decide whether as a matter of policy in exercising its ratemaking function it will distinguish between a poor performer, an average performer, and a superior performer. It has done so in the past, and I believe it should do so in this instance for the reasons I have described above.

CAPITAL STRUCTURE

Q. Do you agree with Mr. Kollen's statement on Page 36, lines 2 through 4, that "The Commission should consider FPL on a standalone regulated utility basis. On a standalone basis, the FPL common equity ratio should be set within the range for a single 'A' utility pursuant to the S&P guidelines"?

A. Not entirely. I agree that the Commission should establish a capital structure for FPL that reflects the specific conditions of the utility. However, I do not agree that this should translate mechanically to setting an equity ratio based on the S&P guidelines for a single 'A' rated utility. Rather, I believe the Commission should take into account the totality of FPL's circumstances and set an equity ratio that will allow the company to maintain roughly the same level of financial strength as it and its customers have enjoyed for the past several years. Continuation of the current 55.83% equity ratio will achieve this objective.

Q. Do you agree with Mr. Kollen's assertion that FPL's equity ratio is excessive?

A. No. FPL's equity ratio, as adjusted for purchase power obligations, is 55.83%; this is only slightly outside the range of 48% to 55% for an S&P 'A' rated utility with a business position of "4." An equity ratio in the upper end of the range is appropriate given FPL's substantial continuing financing requirements to support growth and the necessity of maintaining continuous access to capital, even during times of adverse industry and market conditions.

Q. Do you agree with Mr. Kollen's statement that "...FPL Group Capital is extremely highly leveraged" (Page 34, Line 8)?

A. No. Mr. Kollen appears to be basing his statement on a naïve assessment of Generally Accepted Accounting Principles (GAAP) capitalization ratios, which is quite inappropriate for FPL Group Capital's specific circumstances and which fails to take into account several adjustments made by the rating agencies and investment community to FPL Group Capital's capital structure when evaluating credit strength. Similar to the purchase power obligation adjustment made to FPL's capital structure, the investment community and the rating agencies make certain adjustments to FPL Group Capital financial statements when evaluating balance sheet strength. The two largest adjustments are for nonrecourse debt and equity-linked securities. Nonrecourse debt is project debt whose repayment is secured solely by the particular asset financed and the cash flows generated by the project, with no obligation to repay in whole or in part from corporate funds. Consequently, the rating agencies and investment community distinguish and exclude nonrecourse project debt from FPL Group Capital's capital structure in their credit evaluation. Equity-linked securities are issued in conjunction with a forward equity purchase commitment providing for common equity to be issued on a specific date into a variable number of shares of the common stock of the company, with the number of shares depending on the market price at the time specified. These adjustments have a material effect on FPL Group Capital and FPL Group's capitalization. For example, Standard and Poor's deducted approximately $900 million of project debt in 2004 and assumed the conversion of $1.1 billion of equity linked debentures to equity when evaluating FPL Group's credit strength. In fact, making appropriate adjustments reduces FPL Group's effective leverage to a level close to FPL's capital structure.

Q. Is FPL Group Capital's leverage at all relevant for the Commission to consider in determining a capital structure for FPL?

A. No. Florida Power and Light and FPL Group Capital are two very different businesses. FPL maintains an equity ratio appropriate for its own needs, while FPL Group Capital faces different and in some ways easier circumstances. FPL has an obligation to serve, with substantial near-term unavoidable capital requirements to meet the needs of FPL's rapidly growing customer base. Furthermore, FPL must maintain a strong balance sheet to support its fuel hedging program and ensure quick access to capital and the ability to absorb the temporary balance sheet deterioration caused by items such as fuel under-recoveries and storm fund deficiencies.

In contrast, FPL Group Capital's portfolio consists of businesses with no similar obligation to serve and operating in markets where credit requirements are quite different. The absence of the obligation to serve provides significant flexibility and management discretion, particularly in the timing of capital expenditures. While FPL is likely to be free cash flow negative for the next several years at least, with little flexibility to delay or defer capital expansion, FPL Group management has the flexibility to increase or decrease FPL Group Capital's commitments to meet changing circumstances. In addition, FPL Group Capital has the further ability to isolate and "walk away" from many of its projects were they to become financially distressed. The failure of one specific project would have no necessary connection to the performance of others within the portfolio; in contrast, FPL is a single, integrated system, the failure of one part of which would necessarily entail devastating consequences for other parts.

Q. What should the Commission conclude from the similarities and differences between FPL and FPL Group Capital?

A. FPL Group Capital's circumstances and capital structure is different from FPL's and not relevant to FPL's situation. The Commission should determine a capital structure for FPL that is appropriate for its unique circumstances.

Q. Do you agree with Mr. Kollen's proposed adjustment to FPL's capital structure?

A. No. The capital structure that is currently in place at FPL is appropriate: it is well received by the capital markets, as evidenced by FPL's current credit ratings and overall credit profile, as well as the tight trading spreads of FPL bonds; and it provides the financial flexibility and resilience needed for FPL's rapidly growing peninsula service territory. It would be unwise for the Commission to weaken the Company's financial strength in a period where liquidity and capital access are more important than ever. It is important for the Company to maintain a strong equity ratio given its high growth service territory and exposure to temporary funding requirements for fuel costs and storm expenses which creates more variability in capital requirements. It has been and continues to be appropriate for FPL's circumstances.

Q. Is an adjustment necessary to reflect the effect of parent debt on federal corporate income tax in accordance with Rule 25-14.004(3)?

A. No. Rule 25-14.004 contemplates tax benefits generated by the parent company of a utility subsidiary that has issued debt and invested equity in its subsidiary. FPL Group, Inc., the parent company of FPL, has not issued any such debt. In addition, Rule 25-14.004(3) does not contemplate making an adjustment to a consolidated capital structure. This section specifically excludes the retained earnings of subsidiaries from the capital structure of the parent. This required exclusion results in a non-consolidated equity value for the parent company. Therefore, any debt related to this rule must be debt of the non-consolidated parent company.

COST OF DEBT

Q. Both Mr. Kahal and Mr. Woolridge suggest an adjustment to the cost rate to be applied to prospective long-term debt issues during the forecast period. Do you agree with their adjustments?

A. No. Mr. Kahal cites "current market data and recent cost of debt experience," and Mr. Woolridge cites "current yields on these bonds (30-year A-rated public utility bonds) as well as the recent trends in interest rates," as the basis of their cost of debt assumptions.

The problem with their approach is that setting debt cost assumptions at current rates in a rising interest rate environment will ensure that the Company does not fully recover its financing costs. FPL based its interest rate assumptions for the test year on the projected rates in the December 2004 edition of Blue Chip Financial Forecasts (Blue Chip). Blue Chip is an independent survey that polls approximately 50 of the top economists' projections for U.S. and foreign interest rates, currency values and various economic indicators. Projections are presented for each contributor as well as a top 10 average, bottom 10 average and consensus. FPL utilizes the consensus forecast for long-term corporate bonds as the best estimate of future debt cost rates. This provides the best estimate of what actual financing costs are likely to be in the test year.

While the Company's original cost of debt projections were based on projections from the Blue Chip December 2004 edition, the June 2005 edition continues to anticipate bond yields will rise significantly over the 2005-2006 period covered by its projections.

2007 ADJUSTMENT FOR TURKEY POINT UNIT 5

Q. Mr. Selecky has testified that the Commission should not approve an adjustment for the revenue requirements for Turkey Point 5 because FPL's projected return on equity for 2007 of 11.5% is within the range of return on equity requested in this proceeding. Do you agree?

A. No. One of the outcomes of a rate proceeding is the establishment of revenue requirements that will enable the Company to recover the cost of providing electric service and provide the Company with the opportunity to earn a fair rate of return on its investment. If rates are set to meet these conditions in

2006 then they cannot possibly meet that condition in 2007 and beyond, since the addition of Turkey Point 5 will add to the revenue requirements such a large, discrete amount as to push the earned return down to the bottom end of the proposed range, *ceteris paribus*. If, for example, x% is determined to be a fair and reasonable rate of return for the rate effective year, then building a rate structure knowing that in the following year the earned rate of return will drop by over 60 basis points due solely to the addition of only a partial year of the revenue requirements associated with the commercial operation of a new low cost generating facility, in my view does not provide a meaningful opportunity to earn a fair and reasonable rate of return. The fact that the outcome might still be within the ± 100 basis point band is not relevant because the band is established with the expectation that currently unknown factors are as likely to be positive as negative. In this case, there is an immediate and known bias toward the bottom of the range.

Systematically handicapping this relationship such that the only way the Company can hope to reach its allowed rate of return is through the fortuitous development of currently unknown but positive factors is not consistent with the purpose of ratemaking. The addition of Turkey Point 5 is a significant known and measurable investment with substantial operating and financing costs that are not reflected in FPL's projections for 2006. Further, Turkey Point 5 will have an immediate, substantial, negative impact on FPL's earnings in 2007. A material reduction in ROE in the year following a rate case should not be the result of the successful completion of the least cost generation alternative approved by the Commission to meet the needs of FPL's customers.

Q. If the Company is still earning within its authorized range for return on equity, how would it be harmed?

A. FPL's earned return on equity in 2007 will be materially lower due to the construction of Turkey Point 5 than it would have been had the 2007 need been met through purchased power. If the 2007 need were meet through power purchases, the Company would seek recovery of capacity payments through the Capacity Clause and earned returns would not be impacted. Failure to provide an adjustment to base rates in 2007 for Turkey Point 5 effectively penalizes the Company for delivering to customers the least cost alternative for meeting their needs. The ±1% range around the established ROE is to accommodate unknown or unpredictable factors that may affect future results. The impact of Turkey Point 5 is known and predictable.

Q. Mr. Larkin suggests at page 6 of his direct testimony that the costs of additional capacity can be added through a capacity adjustment clause and thus not affect FPL's average base rate cost per customer. Do you agree with his statement?

A. There is no debate that capacity costs recovered through the fuel and purchased power cost recovery clause do not affect the average base rate cost per customer and would not require a base rate increase. They still, of course, affect the total rate that the customer sees. But unless Mr. Larkin is suggesting that the cost of self build options, determined by the Commission to be the low cost option, also could be recovered through the fuel and purchased power cost recovery clause, his point only emphasizes the bias that could exist in favor of purchased power if the Commission fails to properly reflect the costs of a low cost self-build resource option in the Company's base rates in timely fashion. While I agree that purchasing power is an option, it is not always the best available option, as has been confirmed in the last two Commission Need Determination proceedings, resulting in capital expenditures by FPL in excess of $1.4 billion that are not being recovered through the fuel and purchased power cost recovery clause. The majority of additional capacity added by FPL consists of lower cost repowerings and the construction of new plants that the Commission agreed were more cost-effective from the customers' perspective than any available power purchases. These capacity additions all require significant investment. Mr. Larkin's theory simply does not apply to FPL's actual circumstances.

Q. How will customers benefit from the construction of Turkey Point 5?

A. Turkey Point 5 was determined by the Commission to be the least cost option to satisfy the increased need for generation for FPL's customers. In Order No. PSC-04-0609-FOF-EI, the Commission found that "Final cost comparisons from the RFP evaluation demonstrated that Turkey Point 5 offered a $271 million (cumulative present value revenue requirements, CPVRR) advantage compared to the next most competitive proposal. An independent evaluation confirmed FPL's conclusions. Turkey Point 5 is FPL's best, most cost-effective alternative for meeting the 2007 needs of FPL's customers." Among other benefits, Turkey Point 5 will reduce the fuel component of customers' bills by displacing older, less efficient units for many hours of the year.

Q. Mr. Larkin argues that the adjustment for Turkey Point 5 is not consistent with ratemaking principles in general and, specifically, principles applied in Florida. Do you agree with this assessment?

A. No. I have indicated above why it is obviously inconsistent with ratemaking principles in general not to include the adjustment. In addition, my understanding is that the Florida Legislature has specifically provided for such an adjustment. Section 366.076, F.S. (2003) explicitly provides that the Commission may consider adjustments to base rates in limited scope proceedings. The Commission has exercised that authority in the past. For example, the Commission has allowed for incremental rate increases for Florida Power & Light in 1982 (Docket No. 820097-EU) and 1983 (Docket No. 830465-EI). On page 39 of Order No. 11437, Docket No. 820097-EU, the Commission reasoned that requiring the utility to initiate another full revenue requirements case merely to place this plant in rate base would involve significant regulatory lag detrimental to the utility and substantial amounts of unnecessary rate case expense to be borne by customers. The Commission also previously has approved an additional base rate increase for Florida Progress Energy, then Florida Power Corporation, 30 days after the commercial operation of its Crystal River Unit 5 plant. Docket No. 830470-EI, Order No. 13771.

Q. Messrs. Selecky and Kollen suggest that FPL should be directed to file for a rate increase closer to the time that Turkey Point 5 is placed into service. Why is FPL filing for this limited scope adjustment now?

A. Addressing Turkey Point 5 within the context of the current base rate proceeding is much more efficient. FPL's 2006 test year, which permits a thorough and detailed review of all FPL's costs, ends only six months from the projected in-service date of Turkey Point 5. A subsequent rate proceeding so close to the conclusion of the current proceeding will provide little new information. Given the cost and resources necessary to prepare for a full requirements rate proceeding, we believe it is prudent to address the Turkey Point 5 adjustment within the current proceeding. Additionally, by Order No. 11437, the Commission recognized that a limited scope adjustment is more efficient, as a full revenue requirements case would involve substantial amounts of unnecessary rate case expenses.

Q. Mr. Kollen argues that the 2007 adjustment for Turkey Point 5 should be denied because the projected data for 2007, "fails to consider the effect of the Commission's decisions on the various issues related to the 2006 test year and the Company's real-world responses to those decisions." Do you think that this is a reasonable basis for disallowing the adjustment?

A. No. Mr. Kollen states that "if the Commission determines that the Company's requested O&M expense is excessive in the 2006 test year and the Company responds by reducing O&M expense, then that benefit also would be achieved in 2007 and the twelve months ending May 31, 2008, thus reducing the revenue requirements in those two periods." While I agree with Mr. Kollen's statement that revenue requirements would be lower in those two periods, he fails to recognize the obvious fact that base revenues will also be lower in those two periods if O&M costs were to be excluded in determining revenue requirements for 2006, with no net impact on FPL's expectations of earnings or ROE. The projected return on equity for 2007 assumes the 2006 rate request is approved. If a portion of O&M is disallowed in this proceeding and FPL's base revenue request is reduced, earned returns in 2007 will be lower, all other things equal. The best outcome for the Company if it does lower costs is an 60 basis point drop in earnings due solely to implementing the lowest cost resource option in the form of Turkey Point 5. The issues Mr. Kollen has raised are quite simply irrelevant to the Turkey Point decision.

Q. Messrs. Larkin and Kollen have questioned the reliability of the projected data for the Turkey Point 5 adjustment. What evidence have they provided to support this assertion?

A. None. Messrs. Larkin and Kollen have made broad statements regarding the reliability of the projections. They have not provided any relevant testimony as to why the projections are unreliable. Certainly they did not participate in the Commission's Determination of Need proceeding for Turkey Point 5. The costs and associated revenue requirements for Turkey Point 5 can be, and have been, reasonably estimated. As discussed by Mr. Yeager, there is a high degree of certainty regarding the projected cost of Turkey Point 5 since FPL has contracts in place for major equipment and Engineering, Procurement &

Construction, and it is highly unlikely the costs associated with these contracts will change. These contracts represent the vast majority of construction costs associated with the new unit.

Q. **Is Mr. Larkin's claim that the 2007 adjustment for Turkey Point should be denied because the addition will generate $289 million of additional revenue reasonable?**

A. No. Generally speaking, Mr. Larkin's analysis is flawed because revenue is not derived by taking the maximum output of the unit adjusted by a capacity factor and multiplied by an average rate. Revenue is a function of the number of customers and their usage. Those factors are reflected in the Company's forecasts sponsored by Dr. Green and are included in the overall revenue requirements analysis of this case. By itself, the addition of Turkey Point 5 adds no revenue. Instead, it ensures that FPL can meet its commitment to maintain a 20% reserve margin and sustain high system reliability. Mr. Larkin's analysis also fails to recognize that there are transmission, distribution and administrative costs associated with serving incremental customer load.

STORM ACCRUAL

Q. **Are you surprised that each of the intervenors had a different recommendation regarding the annual storm accrual amount and a target reserve?**

A. No, not at all. It is likely that if five more witnesses had offered testimony, we would have received five additional recommendations that differed. As I indicated in my direct testimony, there is no precisely correct level either for the annual accrual or the reserve. However, I believe the appropriate annual accrual amount and target reserve level should be set so that they are consistent with the Commission's long-standing policies. For reasons explained in my direct testimony, FPL's proposal is consistent with the Commission's past approach to storm cost recovery.

Q. Please summarize your understanding of the Commission's policy on the appropriate reserve balance and annual accrual.

A. The Commission's policy, as articulated in Order No. 95-0264-FOF-EI, is to determine a target reserve balance that is sufficient to protect against most years' storm restoration costs but not the most extreme years. Such a level should reduce FPL's dependence on a relief mechanism such as a special customer assessment. The annual accrual should be set large enough to allow the reserve to build modestly in year's of "normal" hurricane activity, yet low enough to prevent unbounded storm fund growth.

Q. Do you agree with Mr. Kollen's recommendation to recover the expected annual storm damage expense of $73.7 million and to target an average $0 storm damage reserve amount?

A. No. This would be inconsistent with prior Commission orders. The Commission explicitly considered and rejected this approach in Order No. 95-0264-FOF-EI. If a storm fund reserve balance did not exist, the Company would have to rely on emergency relief mechanisms in the event of every major weather event. Emergency relief mechanisms, such as a special customer assessment, tend to create volatility in a customer's bill. The Commission has previously recognized that this is undesirable, since tropical storms and hurricanes are a regular hazard of life in Florida.

Q. **Mr. Stewart performs an analysis to determine the impact on the Storm Reserve Fund if a $120 million annual storm accrual had been implemented in 1990. Do you agree with his analysis?**

A. No. Mr. Stewart's analysis is fundamentally flawed and irrelevant to FPL's current circumstances. The circumstances today are so different compared with 1990 that any analysis that assumes a $120 million accrual commencing in 1990 is meaningless. First, no one would have suggested a $120 million accrual at that time. T&D insurance coverage was still available at a reasonable cost, and the reserve balance was not $0. Second, it is highly unlikely that FPL's reserve balance would ever have gotten as high as $1.48 billion in 2003 as Mr. Stewart suggests. Both the fund level and annual accrual are the subject of annual reports and would have been reconsidered in the intervening years. In any event, a hypothetical and counter-factual re-casting of history is irrelevant to today's circumstances and FPL's current proposal, particularly in light of the Commission's ability to continue to monitor the level of the fund.

Q. **A few of the intervenors (Ms. Brown, Mr. Stewart, and Ms. Merchant) recommend an annual accrual ranging from $20 million to $40 million to**

recover the smaller Category 1 or 2 storms, and they propose that storm securitization or a surcharge could be used to recover any negative balances in the storm reserve. Do you agree with their recommendations?

A. No. With an annual accrual of $120 million, as proposed by FPL, and assuming five years of "good" storm loss experience (storm costs averaging $15 million - $20 million per year) the target reserve level of $500 million would be reached in approximately five years. Consistent with prior Commission orders, FPL believes that a reserve balance is appropriate, as it would not be good public policy to continually recover negative balances through special customer assessments, since they create volatility in customer bills. While FPL is pleased with the passage of the Securitization Bill, that potentially will provide the Commission with another alternative to fund storm costs, it cannot yet be relied upon as a viable option.

Q. **Why do you feel securitization cannot yet be relied upon as a viable option?**

A. First, the funding of securitization bonds is a lengthy process. The Company needs a plan in place now to alleviate future storm costs. At a minimum, the securitization process takes approximately six to nine months, so it will not be completed this year. Second, there is a major unresolved tax issue for securitization. Appropriate tax treatment from the Internal Revenue Service is necessary to make recovery through securitization an economically viable option for FPL and its customers. Specifically, the IRS must confirm that the issuance of the financing order will not be a taxable event. FPL cannot predict whether the IRS will grant the necessary tax treatment. Third, the Commission would have to act on a financing petition filed by FPL. While we are confident the Commission would look favorably on a prudent financing petition, we are not yet in a position where we can submit one. Accordingly, FPL believes it is appropriate to set an annual accrual assuming the existing regulatory framework and modify this value if and when securitization is a reality.

Q. Assuming the Company receives the necessary tax treatment, the Company completes the whole process, and securitization becomes a reality in a year or so, do you feel you still need to collect a $120 million annual accrual?

A. If securitization becomes a reality, and assuming the securitization charges were reflected as a separate line item on the customers' bills and a target reserve level of approximately $500 million were re-established, it would be appropriate to reduce FPL's proposed accrual to some degree. However, I believe this can be addressed if and when the occasion arises in a limited scope proceeding. For now, FPL and this Commission must deal with today's reality, which is that the storm reserve is essentially depleted and must be rebuilt through accruals from base rates. FPL and the Commission must implement rates today that allow FPL to begin to replenish the storm damage reserve, while moving toward a reasonable target given current expected annual losses, as there are no guarantees that the funding of securitization bonds will be completed.

DIRECTOR'S AND OFFICER'S LIABILITY INSURANCE

Q. **Do you agree with Ms. DeRonne's recommendation to remove the cost of Directors and Officers (D&O) liability insurance from FPL's jurisdictional O&M costs?**

A. No. Subsequent to the 2002 passage of Sarbanes Oxley and in light of changing court standards, it is more important than ever for public companies to maintain adequate D&O coverage. D&O liability insurance is a necessary cost of doing business and as such should be reflected in FPL's base rates. Simply stated, by law a corporation must have directors and officers. In today's environment of increased scrutiny and exposure with respect to corporate governance, the risk of liability to directors and officers has increased considerably. Practically speaking, a company could not attract competent, capable officers or directors without D&O liability insurance. Thus, D&O insurance is a cost of business for any corporation. According to a 2004 D&O Liability Survey, done by the Tillinghast business of Towers Perrin, 99 percent of U.S. participants reported purchasing D&O insurance coverage. Certainly, no company of FPL's size would be without such coverage.

Q. **On page 18 of her direct testimony, Witness DeRonne states, "The purpose of D&O liability insurance is to protect shareholders from the**

shareholders' own decisions...The cost associated with the protection of the shareholders' investment should be born by shareholders." Do you agree with her claim?

A. No. The purpose of D&O insurance is to enable the Company to attract and retain qualified, capable directors and officers, without which FPL's performance would surely not be as good as it is and without which it might literally be unable to function over time. This is clearly of direct benefit to customers. Unfortunately, the cost of providing reasonable protection to ensure that directors and officers who prudently and faithfully fulfill their obligations are protected adequately is greater today than it was a few years ago.

Q. Please explain why FPL's directors' and officers' insurance (D&O insurance) premiums increased substantially between 2002 and 2003 and again from 2003 to 2004?

A. In 1998, FPL was successful in negotiating a 3-year fixed cost program with a 3-year single aggregate limit, at rates which we believe were well below market at the time. The three-year single aggregate limit meant that only a single limit would be available for all claims arising during that 3-year period as compared to the normal situation where a new limit is purchased for each year, which helped keep the premium low. In both 2001 and 2002, FPL was successful in extending the 1998 program for additional years. By the end of this program in 2003, there had been a single limit available for all claims arising during the 5-year period of 1998 through 2002. The total premium for this period was about $3.6 million, or an average of a little over $700,000 a year.

With the 2003 renewal, two things occurred. First, the market for D&O insurance changed sharply from its unprecedented low pricing of the prior 5 years or so and there were very significant price increases. Secondly, the market ceased offering multi-year aggregate limit programs and insisted on selling only a new fresh limit in each of the years since.

The result of these two changes was that FPL went from paying below-market rates to a position much more typical of others in the industry, paying $6 million for its D&O program which renewed in 2003 for single year limits of $170 million. In contrast, for limits of $190 million applicable to the prior 5-year period mentioned above, FPL had paid a total of $3.6 million. In 2004, the premium increased again to $8 million reflecting a continuing worsening of the general D&O market.

While the large percentage increase is unfortunate, the current actual cost of D&O is more in-line with the longer term record than was the abnormally low cost of the 1998-2002 period. For example, in 1987, the premium was $6.0 million, or $10.0 million in current dollars, even though the company was then much smaller (size is a major driver of overall D&O cost). In 1993, the premium was $3.7 million or $4.8 million in current dollars- again, for a much smaller company. Adjusted for size and inflation, today's D&O rates are comparable to 1993 and well below those of 1987.

With each insurance renewal, FPL seeks the most competitive insurance pricing available. With a volatile market like D&O, this will inevitably translate into large fluctuations in insurance premiums. The overall D&O market is much tighter today for cyclical reasons and, just as important, has experienced secular increases due to changing legal standards and the effects of the Sarbanes-Oxley Act of 2002 and related changes in corporate governance. FPL has been affected by these changes, but we believe the premiums we are now paying are competitive with those incurred by other comparably sized companies in our industry.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF ROSEMARY MORLEY

DOCKET NOS. 050045-EI, 050188-EI

JULY 28, 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. Did you previously submit direct testimony in this proceeding?

A. Yes.

Q. Are you sponsoring an exhibit to your rebuttal testimony?

A. Yes. I am sponsoring an exhibit consisting of seven documents, RM-11 through RM-17, which is attached to my rebuttal testimony.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address testimony from the following witnesses: Mr. Stephen J. Baron on behalf of the South Florida Hospital & Healthcare Association (SFHHA), Mr. James T. Selecky on behalf of the Commercial Group, and Dr. Dennis W. Goins on behalf of the Federal Executive Agencies (FEA). I also discuss, to a lesser extent, the panel testimony of Ms. Teresa Civic and Mr. Jess Galura on behalf of the Commercial Group. The issues discussed in my rebuttal testimony include the cost of service methodology, the allocation of the revenue increase, the rate treatment for the GSD-1, GSLD-1, and GSLD-2 rate classes, the

Commercial/Industrial Load Control (CILC) rate design, the Optional High Load Factor rate design, and the 2007 Turkey Point Unit 5 adjustment. I also address certain claims made regarding the Company's rates, particularly in terms of the rates available to commercial customers. I will begin by addressing the cost of service methodology.

COST OF SERVICE METHODOLOGY

Q. Please summarize FPL's cost of service methodology and its results as presented in your direct testimony.

A. FPL consistently followed Commission precedent and sound ratemaking principles in developing its cost of service study. As I discuss in my direct testimony, the results of this study clearly indicate that the rates for many classes, particularly those applicable to medium and large commercial/industrial (C/I) customers, are below their cost to serve. Mr. Baron and Mr. Selecky have proposed alternative cost of service methodologies intended simply to shift costs away from their clients in these medium and large C/I rate classes and onto other customers. The intervenors have failed, however, to make a compelling case for replacing the cost of service methodologies presented in my direct testimony.

Q. What cost of service methodology did FPL propose for allocating production plant?

A. FPL used the 12 CP and 1/13th methodology in allocating production plant.

Q. What does Mr. Baron propose in terms of production plant?

A. Mr. Baron proposes to use the average of the single highest monthly summer peak ("Summer Peak") and the single highest monthly winter peak ("Winter Peak") in allocating production plant.

Q. What do you conclude as a result of your review of Mr. Baron's proposal to use an average Summer/Winter Peak in allocating production plant?

A. The Commission should reject Mr. Baron's proposed use of an average Summer/Winter Peak for the following reasons:

- The average Summer/Winter Peak allocation methodology mischaracterizes the generation planning process;
- The Summer Peak and Winter Peak are not consistently the highest two monthly peaks of the year;
- The data fail to confirm the patterns in coincident peak demands by rate class that Mr. Baron claims supports an average Summer/Winter Peak allocation methodology;
- The average Summer/Winter Peak allocation does not send a better price signal than the 12 CP and 1/13th methodology;
- The average Summer/Winter Peak allocation methodology would allocate no production costs to certain rate classes even though all rate classes receive the benefit of FPL's generating capacity.

Q. Why does the average Summer/Winter Peak allocation mischaracterize FPL's generation plan?

A. Mr. Baron states that "the requirement to meet the summer and winter peak demand is driving the capacity resource addition on the system." (Direct Testimony page 29, lines 2-3). This characterization of the generation plan, however, is faulty on three counts. First, Mr. Baron completely ignores the influence fuel savings has on the type of generating units added. While the decision to add additional MW of generation capacity is driven by load requirements, the type of generation capacity added - and thus the total cost of the unit additions - is influenced by the number of hours the units are expected to run. Indeed, if MW capacity were the only consideration in the generation plan, the Company's resources would consist solely of gas turbine peaking units. This is clearly not the case, nor should it be.

Q. What is the second way in which an average Summer/Winter Peak allocation methodology mischaracterizes the generation plan?

The peak demands driving the decision to add additional generation capacity are not based on an average of the Summer Peak and Winter Peak. While it is true that FPL must maintain a 20% reserve margin on both the annual Summer and annual Winter Peaks, the impact each peak has on the planning process is far from equal. Dr. Sim, FPL's Resource Assessment and Planning Supervisor, noted in Docket No. 040206-EI, "For a number of years now, FPL's projected need for additional resources has been driven by the Summer reserve margin criterion." (Direct Testimony, page 7, lines 19-20). Indeed, Mr. Baron indirectly, and perhaps inadvertently, acknowledged this in a footnote on page 30 of his testimony which states, "However, based on the Company's resource plan, FPL is generally adding capacity that maintains a 20% reserve margin in the *Summer* [emphasis added]." Dr. Green provides additional support on this issue in his rebuttal testimony.

Q. Did the Winter Peak drive the need to add the Turkey Point Unit 5?

A. No. As clearly outlined in Docket 040206-EI, the need for the Turkey Point Unit 5 addition was based on the summer reserve margin criterion, not on some average of the summer and winter reserve margins.

Q. If the summer reserve margin criterion has been driving the Company's need for additional capacity why does Mr. Baron propose an allocation based on the average Summer/Winter Peak?

A. Quite simply, by using the average Summer/Winter Peak, Mr. Baron allocates significantly less costs to the customers he is representing and more costs to the residential (RS-1) customers. As shown in Document No. RM-11, for many of the larger rate classes, an allocation based on the Summer Peak methodology generally approximates the allocation based on a 12 CP methodology. For example, the share of production costs allocated to RS-1 is 59.8% under both the 12 CP and the Summer Peak allocation methodologies. Likewise, the share of production costs allocated to GSLD-1 is 8.5% under the 12 CP methodology and 8.3% under a Summer Peak methodology. Under the average Summer/Winter Peak methodology, however, RS-1 share of costs increases to 65.5%. The opposite pattern is found in the larger commercial/industrial rate classes. With an allocation based on the average Summer/Winter Peak methodology, GSLD-1's share of costs declines to 7.3%.

Q. Why does the Winter Peak have such a dramatic impact on the cost allocation by rate class under the average Summer/Winter Peak allocation methodology?

A. Under the average Summer/Winter Peak allocation methodology, the Winter Peak determines 50% of the allocation by rate class. This undue emphasis on the Winter Peak has a dramatic impact on the allocation by rate class because the timing and characteristics of the Winter Peak are so different than that of the other eleven monthly peaks. Most of FPL's monthly peaks tend to occur around the 3:00 PM to 6:00 PM window year round. This is not the case, however, when the Company experiences a cold weather peak, which is usually limited to one monthly peak a year and defines the Winter Peak. The Winter Peak typically happens in the early morning hours, a time when many businesses are closed and the heating requirements of residential customers are at their highest. Hence, residential customers are responsible for a larger share of the Winter Peak than they are of the Summer Peak or the other monthly peaks of the year.

Q. What is the third way in which the average Summer/Winter Peak methodology mischaracterizes the generation plan?

A. In addition to the reserve margin, another criterion in the generation plan is maintaining a loss-of-load probability (LOLP) of 0.1 days per year or less. The LOLP criterion considers peak loads year round and therefore, would not be consistent with a method which considers only two peak hours per year.

Q. What other arguments does Mr. Baron make in support of the average Summer/Winter Peak allocation?

A. Mr. Baron argues that the magnitude of FPL's Summer Peak and Winter Peak are substantially higher than that of the other ten monthly peaks. In support of this, Mr. Baron presents two charts, one based on 2003 and another based on 2005, designed to suggest that the Summer and Winter Peaks are always head and shoulders above the other monthly peaks (Direct Testimony, page 31, Figure 3). A longer view, however, suggests a different story. While the Summer Peak is almost always the highest or second highest monthly peak of the year, the magnitude of the Winter Peak relative to other monthly peaks is much more variable over time. For example, in 2004 the Winter Peak was lower than six of the monthly peaks for the year. A similar pattern was experienced in 2002 and 1998. Mr. Baron's methodology ignores these other monthly peaks which are in many cases higher than the Winter Peak. In total, the Winter Peak was the highest or second highest monthly peak in only four out of the last ten years. This is shown in Document No. RM-12.

Q. What does the analysis shown in Document No. RM-12 suggest in terms of the method used to allocate production plant?

A. The analysis in Document No. RM-12 shows that selectively including certain peak months while excluding others can become an arbitrary exercise. In addition, picking and choosing among monthly peaks is unlikely to produce results that consistently reflect cost causation over time. One of the advantages of the 12 CP and 1/13th methodology is that it does not require arbitrary judgments as to which monthly peaks are important and which are not.

Q. **What patterns in coincident peak contributions by rate class does Mr. Baron allege?**

A. Mr. Baron provides a chart on page 26 of his testimony which allegedly shows that residential customers (RS-1) have experienced disproportionate increases in their average Summer/Winter Peak contributions relative to their 12 CP contributions. Mr. Baron then presents a chart on page 27 designed to suggest that GSLD-1's average Summer/Winter Peak contributions have consistently lagged behind its 12 CP contributions. It appears that Mr. Baron is seeking to demonstrate that the incremental coincident peak demands of residential customers are driving capacity additions while the incremental coincident peak demands of GSLD-1 customers are occurring in off-peak months which, Mr. Baron claims, have no impact on generation costs (Direct Testimony, page 28, line 4-10.)

Q. **What is your assessment of the patterns in coincident peak demands by rate class that Mr. Baron alleges?**

A. As with any graphic analysis of a trend, the starting point, if not selected carefully, can influence the results. In this case, Mr. Baron has selected 1998 as the starting point in an effort to demonstrate an alleged pattern of increasing Summer/Winter Peak demands on the part of RS-1 customers. One might assume that the Summer and Winter Peaks of 1998 were typical of past peaks, but that was not the case. The 1998 Winter Peak, which accounts for 50% of the average Summer/Winter Peak, was an anomaly. Indeed, the 1998 Winter Peak was not a cold weather peak at all, but was the result of a bizarre November heat wave. If a more typical Winter Peak is selected, the trend that Mr. Baron alleges all but evaporates. As shown in Document No. RM-13, the relationship between RS-1's 12 CP versus its average Summer/Winter Peak contribution in the 2006 test year is generally the same as it has been historically based on data since 1995. More importantly, RS-1's contribution to the critical Summer Peak has generally tracked its 12 CP contributions.

Q. What does Document No. RM-13 suggest in terms of the GSLD-1 rate class?

A. Document No. RM-13 shows that the GSLD-1's contribution to the critical Summer Peak is typically higher than its 12 CP contribution - sometimes by a significant margin. This fact clearly contradicts Mr. Baron' claim that GSLD-1's incremental coincident peak demands have been concentrated in the off-peak months (Direct Testimony, page 28, lines 4-10).

Q. Does the average Summer/Winter Peak allocation send a better price signal than the 12CP and 1/13th methodology?

A. No. The 12 CP and 1/13th methodology more accurately reflects the generation plan than does the average Summer/Winter Peak allocation because 1) it recognizes that the type of generation unit selected is influenced by the kWh the unit is expected to run, 2) it better reflects the influence of the summer reserve margin, and 3) it recognizes that capacity must be available throughout the year to meet peak demand consistent with the use of the LOLP criterion in the planning process. Accordingly, the 12 CP and 1/13th methodology will send a more appropriate price signal than an average Summer/Winter Peak allocation methodology.

Q. **Are there any other factors which should be considered in determining the appropriate method of allocating production plant?**

A. Yes. The Commission has long recognized that one of the advantages of the 12 CP and 1/13th methodology is that it ensures that each rate class pays some portion of the production plant it uses (Docket No. 820097-EU, Order No. 11437.) By contrast, methods such as the average Summer/Winter Peak allocation which are limited to one or two hours a year can result in some rate classes contributing nothing towards production plant even though such rate classes clearly benefit from – and rely on – the system's production resources. This is evident in Document No. RM-11 which shows that three rate classes are allocated no production plant costs using an average Summer/Winter Peak allocation.

Q. **Do you have any other comments regarding Mr. Baron's proposed use of the average Summer/Winter Peak allocation?**

A. Yes. The use of a 12 CP and 1/13th methodology has an extensive history of regulatory approval in Florida and over the years the Commission has clearly articulated why it believes the methodology is appropriate. Accordingly, it would be reasonable to expect that consideration of an alternative method would be made only to the extent that a clear and compelling case is made for that alternative method. After all, Mr. Baron himself found the 12 CP and 1/13th method "reasonable" for FPL's use as recently as 2002 (Docket 001148-EI, Direct testimony of Stephen Baron, page 6, line 20). After reviewing the arguments Mr. Baron now presents in support of an alternative methodology, one based on an average Summer/Winter Peak, it is obvious that a clear and compelling case has not been made. The Commission should approve the 12 CP and 1/13th methodology as proposed by the Company.

Q. Are there any other cost of service issues raised in the intervenors' testimony to which you would like to respond?

A. Yes. I would like to respond to Mr. Baron's and Mr. Selecky's advocacy of the minimum distribution system (MDS) or zero intercept system method for allocating distribution plant.

Q. How does the MDS method compare with the Company's proposed method of allocating distribution plant?

A. FPL's methodology classifies meters, service drops, and primary pull-offs as customer-related and classifies the remaining balance of distribution plant as demand-related. Thus, under FPL's methodology substations, poles, conductors (excluding primary pull-offs) and transformers are classified as demand-related and are allocated among the rate classes using various measures of peak demand. The MDS method classifies a portion of poles, conductors and transformers as customer-related and allocates these costs among the rate classes based on the number of customers. The MDS method determines the customer-related portion of these facilities on the basis of a hypothetical distribution system constructed to serve the minimum load requirements of customers. Under the MDS method, minimally sized transformers, poles, and conductors are used as the basis for constructing this minimum load requirements system. A variant of the MDS method, the zero intercept method uses statistical extrapolation to determine a hypothetical customer-related portion of poles, conductors and transformers.

Q. What impact would the MDS method have on the allocation of costs by rate class?

A. By reclassifying demand-related costs as customer-related, the MDS method would increase the amount of distribution plant allocated to residential and very small commercial customers. Larger customers, such as those in the GSLD-1 rate class, would benefit through a reduced allocation of costs.

Q. What do you conclude from your review of Mr. Selecky's and Mr. Baron's testimony on the MDS method?

A. The Commission should reject the use of the MDS method for the following reasons:

- The Commission has consistently rejected the use of the MDS method for investor owned utilities and a compelling case for ignoring that precedent has not been made in this case;
- The MDS method presumes a type of electric system and a method of planning which is not reflective of FPL's distribution system;
- The MDS method assumes unique characteristics on the part of the electric utility, including low customer density, highly sporadic

loads, a high ratio of accounts per customer location, and an inability to adequately recover costs absent the use of the MDS method, none of which are applicable to FPL;

- The economies of scale argument made by Mr. Baron ignores the impact of density, diversity and double-counting;
- Mr. Baron has inappropriately estimated the impact of the MDS method.

Q. Has the MDS method ever been approved for an electric investor owned utility (IOU) in Florida?

A. No. The issue has been considered by the Commission numerous times and has been consistently rejected, most recently in 2002 (Docket No. 010949, Order No. PSC-02-0787-FOF-EI). Moreover, the Commission's findings regarding the MDS method in that order are applicable in this case, as I address in the discussion below.

Q. Why does the MDS method presume a type of electric system and a method of planning which is not reflective of the FPL distribution system?

A. The MDS method assumes that a certain investment in transformers, conductors and poles is required solely as a result of connecting customers to the electric system. Consequently, the MDS method is based on a set of distribution facilities designed to service the zero or minimum load requirements of customers. As the Commission states in Order No. PSC-02-0787-FOF-EI, "The concept of a zero load cost is purely fictitious and has no grounding in the way the utility designs its systems or incurs costs because no utility builds to serve zero load." Moreover, the Commission's analysis is consistent with FPL's distribution planning. The central criterion used in planning the FPL distribution system is kW load requirements, not customers served.

Q. Does this mean that the need to serve individual customers never influences distribution plant additions?

A. No. There are certainly cases where line extensions are required to serve specific customers. This is where a strong and consistently enforced contribution in aid of construction (CIAC) policy comes into play. As outlined in the Florida Administrative Code (FAC 25-6.064), customers are required to pay for the cost of any line extension to the extent that the expected revenues do not offset the cost of the line extension. In this manner, customers with "minimum load requirements" must pay for the cost of any line extensions required to service them. This is a far more equitable outcome than the cost allocation resulting from the MDS method since the specific customers necessitating the line extension bear the cost.

Q. Would the requirement to pay a line extension CIAC be limited to large commercial/industrial customers?

A. Not at all. A CIAC would be required in any case where the expected load and revenue does not offset the required investment. In fact, the CIAC line extension formula is routinely applied to new residential subdivisions.

Q. Has a MDS method ever been approved for any electric utility in Florida?

A. The sole case in which the MDS method was approved involved an electric cooperative, the Choctawhatchee Electric Cooperative, in 2002.

Q. Does the Commission decision with regard to the Choctawhatchee Electric Cooperative in any way alter its policy against the MDS?

A. No. The Commission decision (Docket No. 020537-EC, Order No. 02-1169-TRF-EC) made it clear that the Choctawhatchee Electric Cooperative possessed "unique characteristics" which justified this departure from precedent.

Q. Are these "unique characteristics" shared by FPL?

A. No, they are not. First, the Commission cited Choctawhatchee Electric Cooperative's low customer density. The Commission noted that the Cooperative has a customer density of 10 customers per square mile while most IOUs have a density of 54 customers per square mile or greater. As I present in Document No. RM-14, FPL's density is 149 customers per square mile or roughly 15 times greater than that of Choctawhatchee Electric Cooperative.

Q. Why is customer density a consideration in evaluating the appropriateness of the MDS method?

A. Pockets of geographically isolated customers could require a greater number of poles and a longer span of conductors to provide service than would be the case in more urban settings. Thus, a rural utility could find that the MDS method adequately reflects their planning process. FPL, on the other hand, has a high customer density. As shown on Document No. RM-14, the Company's customer density is dramatically higher than that of a rural cooperative. In fact, the Company's customer density is even high relative to other IOUs. Moreover, FPL's customer density has increased significantly over time and is projected to continue increasing over time as our load grows.

Q. Does customer density influence any distribution facilities besides poles and conductors?

A. Yes. The MDS method assumes that there is some minimally sized transformer required to connect customers regardless of their load. In utilities with very low customer density, the notion of a minimal load transformer may have some validity because in sparsely populated rural areas there is usually one transformer per customer. By contrast, in more urban areas several customers may be served from one transformer. This is certainly the experience at FPL where serving 5-6 residential customers or more from a single transformer is standard.

Q. What other "unique characteristics" did the Choctawhatchee Electric Cooperative have?

A. The Commission noted that the Cooperative's rural service territory experiences greater seasonal variability than is typically found in more urban electric utilities. The Commission noted that the cooperative supplies service to "a significant number of barns, stock tanks, electric fences, hunting cabins, and vacation homes." Proponents of the MDS method suggest that highly sporadic loads may support the use of this method because a rate design based on relatively low customer charges and high energy charges may not adequately recover costs.

Q. Are FPL loads highly sporadic in this manner?

A. No. Less than 5% of residential accounts consume a minimal amount of electricity, i.e. 100 kWh or less, in any given month.

Q. Are highly sporadic loads cited as a reason in this case for adopting the MDS method?

A. Yes. Mr. Baron states that there are a significant number of vacation homes in the Company's service territory (Direct Testimony, page 47, lines 14-16). Mr. Baron cites a hypothetical example of a single family home used 50 days a year and claims that this type of customer would not be allocated any distribution plant costs under the Company's cost of service methodology unless the customer happens to be on at the time of the rate class's group peak. Mr. Baron, however, offers no evidence whatsoever for the alleged significance of vacation homes in FPL's service area. In fact, the data show that less than 5% of FPL's residential accounts have minimal loads (i.e. 100 kWh or less) in any given month. The percentage of accounts with consistently minimal loads (i.e. under 100 kWh per month for all but 50 days per year) would, by definition, be even less.

Q. Did the Commission offer other examples of the "unique characteristics" of the Choctawhatchee Electric Cooperative that made the MDS method appropriate?

A. Yes. The Commission noted that the ratio of accounts per customer location was quite high. The cooperative's rural customer base was cited as the reason for this high ratio. For example, a farm could have a residence, a barn and an electric fence all on different meters. Assuming such a configuration, a customer's total load would be divided among multiple accounts, thus increasing the utility's connection costs. Lastly, the MDS method was approved in part because of the cooperative's financial hardships under the assumption that higher customer charges would help stabilize revenues. Again, neither of these two reasons would be applicable to FPL.

Q. **Given the background on the MDS method you've provided, what arguments do Mr. Baron and Mr. Selecky make for advocating such a dramatic change in the Commission policy regarding the allocation of distribution plant?**

A. Mr. Baron states that the MDS is necessary because of what he refers to as the economies of scale in certain distribution facilities (Direct Testimony, page 41, lines 3-4). The economies of scale argument also appears to be the rationale behind the schematic diagram Mr. Selecky presents on page 16 of his testimony.

Q. **Do you find this argument convincing?**

A. No, I do not. The MDS method shifts all benefits from economies of scale to the larger customers even though there are economies of scale in serving residential customers. In dense urban areas not only are multiple residential customers frequently served off the same transformer but the size of such a transformer is frequently comparable to that used for commercial customers. The diversity of residential customers' loads also creates economies of scale. Because each residential customer's maximum demand will not coincide exactly with other customers' on the same transformer engineering procedures dictate that transformers serving multiple residential customers need not be sized to serve the sum of every customer's maximum demand. Mr. Selecky's schematic on page 16 of his testimony would suggest that a new transformer is required for every three residential customers added to the system. In reality, distribution planners can and do routinely add new customers to existing transformers because of the diversity of residential loads. By contrast, no such diversity is applicable to a large commercial customer served from a single transformer.

Q. **Are these the only problems with the MDS method as it is applied to transformers?**

A. No. Another problem with the MDS method as espoused by Mr. Baron and Mr. Selecky is that it would double count the kW loads of residential and the smallest commercial customers for the investment in transformers associated with their so-called minimal load requirements.

Q. **Why does this double counting occur?**

A. This double counting occurs because the RS-1 and the smallest commercial rate class (GS-1) are first allocated the cost of the so-called minimum load transformers based on the number of customers. The remaining cost of transformers is then allocated to RS-1 and GS-1 on the basis of their maximum customer peaks, with no adjustment for that portion of the maximum customer peaks which is provided under the minimum load transformer.

Q. **Do Mr. Baron and Mr. Selecky offer any other arguments for applying the MDS method in this case?**

A. Mr. Selecky claims that a number of other jurisdictions are using the MDS method (Direct Testimony, page 16, lines 3-7). The use of a cost of service methodology in a different jurisdiction should not be interpreted as the decisive factor supporting its application in Florida. Accordingly, the use of the MDS method by Gulf's sister company was not found to be a compelling factor in Order No. PSC-02-0787-FOF-EI. Mr. Baron and Mr. Selecky also claim that the NARUC Electric Manual endorses, if not requires, the use of the MDS method. However, as the Commission has already observed, the NARUC manual states that the choice of methodology will depend on the unique circumstances of the case (Docket No. 010949-EI, Order PSC-02-0787-FOR-EI, page 66).

Q. Do you have any other comments regarding the intervenors' support for the MDS method?

A. Yes. Mr. Baron has quantified the impact from the MDS method by applying the classification between demand and customer costs developed for Gulf Power Company to FPL's cost of service study (Direct Testimony, page 49, lines 2-5). Under the best of circumstances assuming that two electric utilities have an identical cost structure is problematic. In this case, using Gulf Power Company to illustrate the impact of the MDS method is particularly inappropriate. As discussed earlier, customer density has been recognized as a factor in evaluating the MDS method. As shown in Document No. RM-14, FPL's density of 149 customers per square mile exceeds Gulf's 54 customers per square mile by a factor of almost 3 to 1.

Q. Do you have any other comments regarding Mr. Baron's cost of service analysis?

A. Yes. On Table 6, page 51 of his testimony Mr. Baron shows the parity figures resulting from the average Summer/Winter Peak treatment of production plant combined with the MDS method for distribution plant. I am unable to confirm Mr. Baron's calculation and in no way endorse the use of either an average Summer/Winter Peak treatment of production plant or the MDS method for distribution plant. Nevertheless, I think it is important to point out that, even with the dramatic methodology changes Mr. Baron is advocating, a number of the larger commercial rate classes (GSLD-1, GSLD-2, and CS-2) remain below parity.

ALLOCATION OF THE REVENUE INCREASE

Q. Can you briefly summarize the Company's proposal on allocating the revenue increase?

A. Yes. As I discussed in my direct testimony, the Company proposes to move the majority of rate classes to within +/- 10% of parity. Because the Company's rates have not been adjusted to improve parity in more than twenty years there are widely disparate parities by rate class. For example, two rate classes, outdoor lighting (OL-1) and the standby service to customers below 500 kW (SST1-DST), are not even earning positive rates of return. In other words, these rate classes are not even earning enough to offset the operating expenses allocated to them, much less make any contribution to capital costs. Likewise, two other specialty service rates, namely street lighting (SL-1) and sports field lighting (OS-2), are earning less than 50% of the average rate of return. At the other end of the spectrum, other rates are earning 50% more than the average rate of return. The largest group in this regard is the GS-1 rate class which consists of the smallest commercial customers. The Company's proposal would provide an important – and necessary – step in addressing these discrepancies.

Q. What positions have the intervenors taken on this issue?

A. Each of the intervenors filing testimony on this issue, Mr. Baron, Mr. Selecky, and Dr. Goins, acknowledge the goal of moving rate classes closer to parity. However, the intervenors advocate a limit of 150% of the system average be applied to any rate class's increase. The intervenors argue that in past cases the Commission has relied on a rule-of-thumb that limits the increase to any rate class to no more than 150% of the system average increase.

Q. Does the Commission's past use of this rule-of-thumb dictate its use in this case?

A. No. The Commission has recognized that there may be circumstances in which the rule-of-thumb should not be applied. Specifically, in Docket 810136-EU, Order No. 10557, pages 29-30 (the "Gulf Case") the Commission rejected the use of the 150% rule-of-thumb. In that case the Commission ruled "we are departing from our policy in previous cases of limiting the increase to any one class to no more than 1.5 times the system average increase. Were we to apply that policy in this case, some classes whose present rates of return are above parity would receive an increase.

Thus, the greater equity lies in allocating the increase to those rate classes with substantially lower rates of return."

Q. **What meaning do you ascribe to the Commission's reference to "the greater equity"?**

A. That it is inherently fair and equitable to align each rate class's revenues with its cost of service. Limiting the revenue increase to any individual rate class to a certain threshold may appear to be equitable, but the benefits of doing so should be balanced against the added revenue burden other customers would be required to bear and the disparities in parity by rate class which would continue to perpetuate as a result. As the Commission found in the Gulf case, the revenue burden on other customers and the disparities in parity by rate class can be such that the use of the rule-of-thumb is inequitable.

Q. **How did the parities by rate class in the Gulf case compare with FPL's in this filing?**

A. The parity by rate class in the Gulf case ranged from 81% to 145%. By contrast, the FPL's cost of service study shows parities by rate class ranging from less than zero to in excess of 150%. Thus, the inequity resulting from the use of the rule-of-thumb would be far greater in this case than would have been in the Gulf case.

Q. **If the rule-of-thumb were applied in this case which rate classes would have to shoulder a revenue increase in excess of their cost of service?**

A. The RS-1 class, by virtue of its size and the fact that it is above parity, would end up shouldering a revenue increase in excess of its cost of service if the rule-of-thumb were applied in this case. The use of the rule-of-thumb would increase the target revenues required from RS-1 by $18 million or 8.4% more than the $214 million proposed in the Company's filing. Moreover, under the conventional rule-of-thumb the total base revenue increase for RS-1 would be only a fraction below the system average increase requested even though RS-1 parity at 106% is substantially higher than that of most other classes. In other words, under the rule-of-thumb there would be little effort to align costs and revenues in the RS-1 rate class, a class that represents almost 90% of our customers.

Q. Are there any other compelling reasons why the rule-of-thumb should not be applied in this case?

A. Yes. In past circumstances reasonable progress toward parity may have been achievable using the rule-of-thumb. For example, in Docket No. 830465-EI when the rule-of-thumb was last applied to FPL's rates, only one rate class was left with a parity index below 90%. By contrast, in this case, half of all rate classes would be left with a parity index below 90% if the rule-of-thumb were used.

Q. Do you have any other comments regarding the allocation of the revenue increase by rate class?

A. Yes. Mr. Baron advocates a uniform revenue increase across all rate classes (Direct Testimony, page 51, lines 6-8). The suggestion is based on the application of cost of service methodologies which I do not support and have already addressed. Nevertheless, even Mr. Baron's calculations show parity indices ranging from -54% to 618%. How such widely disparate parity indices "support the allocation of approved revenue increases on an equal percentage increase for all rate schedules" as Mr. Baron claims, is difficult to comprehend.

GSD-1, GSLD-1, AND GSLD-2 RATE CLASSES

Q. Have the intervenors raised any issues in terms of the treatment of specific rate classes?

A. Yes. Mr. Selecky objects to the Company's proposed rates for GSD-1, GSLD-1, and GSLD-2 rate classes. (Direct Testimony, page 23, lines 3-6).

Q. What are the GSD-1, GSLD-1 and GSLD-2 rate classes?

A. Currently, the Company has three different distribution-voltage demand meter general service rate classes depending on the customer's kW. They are GSD-1 (21-499 kW), GSLD-1 (500-1999 kW), and GSLD-2 (above 2000 kW). As ordered by the Commission, each of these rate classes has the same demand charge while the energy charges vary inversely with the rate class's kW threshold.

Q. How have customers reacted to this rate structure?

A. In certain cases, customers have attempted to circumvent the rate structure by artificially inflating or "spiking" their kW demand so as to qualify for the lower energy charges associated with the GSLD-1 rate class. (See Document No. RM-15, Docket No. 030623-EI, Hearing November 4, 2004, Witness George Brown, transcript pages 194-199). Other customers have merely complained that "the 500 kW demand level does not have any 'magic' that reduces FP&L costs of providing service." (Direct Testimony of Sheree L. Brown on behalf on Publix Super Markets, Inc, Docket No. 001148-EI).

Q. What does the cost of service study show in terms of the cost of serving customers below the 500 kW threshold and those above it, in other words those in the GSD-1 and GSLD-1 rate class?

A. As shown in the figures below, the energy unit costs are nearly identical for both classes while the demand unit cost is considerably higher for the GSLD-1.

Rate Class	GSD-1	GSLD-1	difference
Energy Unit Costs, cents/kWh (1)	.504	.503	0%
Demand Unit Costs, $/Billing kW (2)	8.96	11.15	24%

Sources:

(1) Energy revenue requirements from MFR E-6b divided by kWh sales

(2) Demand revenue requirements from MFR E-6b, divided by billing kW without the 10kW exemption

In addition, as I discuss later in my testimony, production and transmission demand costs are more appropriately recovered on an energy basis than through billing kW. Thus, the proposed unit costs for rate design are as follows:

Rate Class	GSD-1	GSLD-1	difference
Energy Unit Costs, cents/kWh (1)	2.09	1.97	-6%
Demand Unit Costs, $/Billing kW (2)	3.40	4.30	26%

Sources:

(1) Energy revenue requirements plus production and transmission demand revenue requirements from MFR E-6b divided by kWh sales

(2) Distribution demand revenue requirements from MFR E-6b, divided by billing kW without the 10 kW exemption

Q. What did you conclude from this?

A. I conclude that there is no basis for the assumption that the cost to serve customers automatically reduces when a customer moves from 499 kW to 500 kW. Indeed, *whether one follows my suggested unit cost calculation or the method advocated by Mr. Selecky, the cost of GSLD-1 is, if anything, higher than the cost of serving GSD-1 customers.* In short, the current rate structure which artificially reduces a customer's bill upon reaching 500 kW is flawed.

Q. How should this problem be addressed?

A. One option would be to increase both the GSD-1 and GSLD-1 rate classes to their full cost of service. However, this proposal would likely result in GSLD-1 customers paying *more* than GSD-1 customers. As a compromise, it is reasonable to evaluate whether the demand and energy charges for GSD-1 and GSLD-1 should be made equal. There are numerous cases where existing rate classes have been combined for ratemaking purposes (Docket No. 910890-EI, Order No. PSC-92-1197-FOF-EI; Docket No. 810002-EU, Order No. 10306). The Commission offers guidance on evaluating whether rate classes should be collapsed for ratemaking purposes. Specifically, the Commission has used the ratio of load factor to coincidence factors to evaluate whether rate classes should be combined

(Docket No. 820150-EU, Order No. 11498). The ratio of load factor to coincidence factor for the GSD-1 and GSLD-1 classes is as follows:

GSD-1: 76%

GSLD-1: 81%

Thus, the rate classes' ratios of load factor to coincidence factor are comparable. This suggests that the load characteristics of the rate classes are reasonably close and the use of a single set of demand and energy charges is appropriate.

Q. Does FPL propose applying the single set of demand and energy charges to other rate classes?

A. The Company proposes to include GSLD-2 in the combined rate treatment since its unit costs are comparable to those of GSLD-1. The corresponding curtailable (CS) rate classes would also be included in this proposal since the only difference between the otherwise applicable GSLD rates and the CS rate classes is the curtailable credit. At the same time, separate customer charges would be set for each rate class.

Q. How have the intervenors reacted to this proposal?

A. As previously referenced, Mr. Selecky on behalf of the Commercial Group suggests that there is no basis for combining the GSD-1, GSLD-1, GSLD-2, CS-1, and CS-2 rate classes. The above analysis, however, supports the Company's proposal. Mr. Selecky also implies that the revenue increases for GSLD-1 and GSLD-2 are somehow inflated because of the Company's proposal to have a single set of demand and energy charges for GSD-1, GSLD-1 and GSLD-2. The opposite is true. While the Company would prefer to move all rate classes to within +/- 10% of parity, the parity targets for the GSLD-1 and GSLD-2 were reduced from 90% to 80% and 82% respectively in order to: 1) achieve a standard set of demand and energy charges; and 2) to account for the revenue loss associated with the Optional High Load Factor rate the Company is offering.

Q. Did Mr. Selecky raise any other issues regarding the GSD-1, GSLD-1, and GSLD-2 rate classes?

A. Yes. Mr. Selecky disagrees with the specific energy and demand charges proposed for GSD-1, GSLD-1, and GSLD-2 rate classes (Direct Testimony, page 25). Under the Company's proposal the demand charge would recover all distribution demand-related costs and a portion of production and transmission demand-related costs while the energy charges would recover the remaining portion of demand-related production and transmission costs as well as all energy-related costs. Mr. Selecky, on the other hand, opposes the recovery of any production or transmission demand-related costs through the energy charges.

Q. Why is the Company proposing to recover a portion of its demand-related production and transmission costs through the energy charge?

A. The decision on which billing determinant should be used to recover a particular cost should be based on an evaluation of which billing determinant best tracks those costs. In the case of demand-related production and transmission costs the costs are allocated on the basis of 12 CP contributions. Thus, to the maximum extent possible, the billing determinant used to recover production and transmission demand-related costs should track a customer's 12 CP contributions. Since customers are not billed on the basis of their 12 CP contributions, this becomes a question of whether kWh sales or billing kW better mirrors a customer's 12 CP contribution.

The data clearly show that kWh sales more closely track customers' 12 CP contributions than billing kW does. Over time, increases in billing kW within the GSLD-1 rate class have fallen short of increases in either kWh sales or 12 CP contributions.

Cumulative Increases (1984-2006) - GSLD-1

kWh Sales	153%
Billing kW	117 %
12 CP	162%

In addition, a statistical analysis shows that the correlation between kWh sales and 12 CP contribution is greater than that between billing kW and 12 CP contributions.

Correlation Coefficient with 12 CP - GSLD-1 Sample Points

kWh Sales (1) 97%

Billing kW (2) 93%

Notes (1) – annual kWh sales

Notes (2) – maximum monthly kW demands

Q. Is the use of a correlation analysis a common technique for determining how demand-related production and transmission costs should be recovered?

A. Yes, it has been used in a number of Commission decisions, including Docket No. 830470-EI, Order No. 13771 and Docket No. 840086-EI, Order No. 14030.

Q. Are the results of the correlation analysis consistent with past experience?

A. Yes. The Commission has long recognized that there is an inherent mismatch between billing kW and the 12 CP demands which are used to allocate production and transmission demand costs. In Docket 930759-EG, Order No. PSC-93-1845-FOF-EG, the Commission determined that it was not appropriate for FPL to recover demand-related costs on a billing kW basis because of the mismatch between billing demand and coincident peak demand. The Commission specifically recognized that "for billing purposes, an individual customer's maximum demand (billed kw) is determined by the customer's greatest amount of continuous use during any 30 minute time period. The customer's billed kW may or may not occur when the system is at its peak."

The Commission has also recognized this "mismatch" in approving the rates for other utilities. In Docket No. 830470-EI, Order No. 13771, pages 46-47, the Commission concluded that "increasing the proportion of demand-related costs recovered through demand charges is inequitable to low load factor customers when KWH's are as highly or even more correlated with coincident demand than billing demand and when there is a wide variation of coincidence factors within a class." Thus, the Commission has approved recovering costs allocated on a 12 CP basis on a kWh energy basis.

Q. **Does Mr. Selecky perform any statistical study indicating that billing kW tracks 12 CP demands better than kWh sales does?**

A. No.

Q. **Then what basis does Mr. Selecky offer for opposing the recovering costs allocated on the basis on 12 CP on the basis of kWh sales?**

A. Mr. Selecky claims that all demand-related costs, including those allocated on the basis of 12 CP, should be recovered through the demand charges in order to send the right price signal to customers (Direct Testimony, page 25). Yet, Mr. Selecky does not explain why the recovery of 12 CP costs through the demand charge sends an appropriate price signal when kWh sales clearly does a superior job of tracking these costs.

CILC RATES

Q. **Please discuss the testimony of Federal Executive Agencies witness Goins relating to the CILC rate schedules.**

A. In his direct testimony, Dr. Goins proposes an adjustment to exclude the "energy-related gas turbine production costs included in FPL's proposed energy charge" for the CILC-1G; CILC-1D; and CILC-1T rate schedules (Direct Testimony, page 17, lines 18 – 21).

Q. What do you conclude as a result of your review of Dr. Goins' proposed adjustment?

A. The Commission should reject Dr. Goins' proposed adjustment to the CILC energy charges for the following reasons:

- It is inconsistent with the cost of service methodology proposed by FPL and supported by Commission precedent;
- It is inconsistent with FPL's resource plan;
- It would be costly and impractical to implement;
- It has not been calculated correctly.

Q. Why is Dr. Goins' proposed adjustment to the CILC energy charges inconsistent with the cost of service methodology proposed by FPL and supported by Commission precedent?

A. As I have previously discussed, the Commission, in evaluating the appropriate method of allocating production plant, has recognized that a portion of these costs should be allocated on the basis of kWh. Consistent with Commission precedent, FPL is proposing a 12 CP and $1/13^{th}$ methodology which classifies approximately 8% of production plant as energy-related. The adjustment proposed by Dr. Goins is clearly at odds with the 12 CP and $1/13^{th}$ methodology because under his proposal CILC rates would not recover their share of gas turbines classified as energy-related.

Q. What basis does Dr. Goins offer for proposing rates which do not follow the 12 CP and $1/13^{th}$ methodology?

A. The basis for the adjustment as proposed by Dr. Goins is described as follows:

FPL's CILC interruptible service option is primarily used to reduce peaking (that is, gas turbine) capacity requirements. Requiring CILC customers to pay energy-related nonfuel gas turbine production costs is inconsistent with excluding demand-related gas turbine production costs form the CILC Load Control On-Peak demand charges. (Direct Testimony, page 17, lines 11 – 14)

Q. Do you find Dr. Goins' argument compelling?

A. No, I do not. Implementing Dr. Goins proposed adjustment to the energy charges for the CILC rate schedules, is inconsistent with the cost of service methodology proposed by FPL and supported by Commission precedent. As I observed in my direct testimony, "all generating units under the 12 CP and 1/13th methodology are treated consistently." (page 17, lines 4-5). Dr. Goins' proposed adjustment would isolate the cost of one type of generating unit, gas turbines, and exempt certain rate classes from the cost of those units appropriately allocated to them on the basis of the 12 CP and 1/13th methodology.

Q. Is Dr. Goins' proposed adjustment to the energy charge for the CILC rate schedules inconsistent with Dr. Goins' own conclusions regarding the 12 CP & 1/13th methodology?

A. Yes. His proposed adjustment is particularly surprising given his recognition of the "Commission's past support" (Direct Testimony, page 6, lines 6 – 7), and his own assessment and conclusion regarding FPL's filed cost of service study. In numerous points in his testimony Dr. Goins assesses FPL's cost of service study as "reasonable." (Direct Testimony, page 7, line 25 through page 8, line 2, page 9, lines 19 – 21, page 9, line 26 through page 10, line 2).

Q. What impact does exempting certain rate classes from the costs appropriately allocated to them on the basis of the 12CP and 1/13th methodology have?

A. Dr. Goins appropriately observes that, if a "cost-of-service methodology does not allocate and assign cost responsibility in a reasonable manner, then interclass revenue subsidies are created and specific class rates are either over- or under-priced." (Direct Testimony, page 7, lines 20 – 23). Unfortunately, such interclass subsides are certain to result from Dr. Goins' proposed CILC energy adjustment. Dr. Goins calculates a maximum revenue impact of approximately $2 million from his proposal, but he makes no recommendations as to how this revenue shortfall is to be recovered. The effect of Dr. Goins' failure to address the recovery of the $2 million revenue impact of his proposed adjustment raises the near-certainty that "interclass revenue subsidies are created and specific class rates are either over- or under-priced."

Q. Why is Dr. Goins' proposed adjustment inconsistent with FPL's resource plan?

A. From an FPL resource planning perspective the net kWh energy reduction from the CILC program is negligible. This is because FPL's resource plan makes the following assumptions: 1) the number of CILC load control events is limited, 2) load control events typically call on only a portion of CILC's interruptible load, and 3) the majority of any unserved energy resulting from a load control event will be served later. Thus, implementing an adjustment to the energy charge for the CILC rate schedules on the basis of their non-firm peak load characteristics is inconsistent with FPL's resource plan. Dr. Green's testimony also addresses this point.

Q. Why is Dr. Goins' proposed adjustment costly and impractical to implement?

A. Dr. Goins' proposed adjustment requires that the energy charge for the CILC rate schedules distinguish between firm and non-firm usage based on an assumed load factor and the level of controllable versus firm demand contractually specified by the CILC customers in their agreement for CILC service. (Direct Testimony, page 18, lines 4 – 11) Dr. Goins ignores the significant revision to the billing system that would be necessary for these CILC rate schedules in order to implement his proposed adjustment. The existing billing system for these CILC rate schedules has no capability to distinguish firm versus non-firm energy usage and apply separate energy charges to each. This revision is also significant because the implementation of Dr. Goins' methodology requires an assumption concerning load factor and the customers' contractual designation of controllable versus firm load which must also be reflected in the billing system for these CILC rate schedules. While I have not determined a specific estimate, my experience in implementing other rate revisions suggests that significant time and resources would be required. Given the commitment of resources required to implement the revised rates FPL is proposing in this docket, implementing the change Dr. Goins is proposing in 2006 as well would be extremely difficult. The time and resources required to make the billing changes Dr. Goins is proposing should also be evaluated in light of the fact that the CILC rate schedules have been closed to new customers for a number of years.

Q. **Please describe the calculation of Dr. Goins' proposed adjustment.**

A. As described by Dr. Goins, this adjustment is implemented by excluding the cost of "gas turbine production capacity" expressed on a cents/kWh basis from the energy charge for the CILC rate schedules. Dr. Goins specifies "gas turbine production capacity" in numerous references in his testimony (Direct Testimony, page 17, lines 10-14 and lines 18-21).

Q. **Was Dr. Goins' proposed adjustment calculated correctly?**

A. No.

Q. **What problem did you find with the calculation of Dr. Goins' proposed adjustment?**

A. Dr. Goins intended to base his adjustment to the CILC energy charge on the cost of gas turbine production but instead used the costs for both gas turbines and combined cycle production units. As shown in the cost of service study filed in this docket, there are three production cost categories: Steam; Nuclear; and Other. These three categories are shown in MFR E-1, E-3a and E-4a. Additional detail on the composition of "Other Production" plant was provided in MFR B-8. MFR B-8 shows that the Other Production cost category includes the cost of gas turbines at Ft. Myers, Ft. Lauderdale, and Port Everglades. That category, however, also includes the combined cycle units at Ft. Myers, Manatee, Martin, Putnam, and Sanford power plants. MFR B-8 shows that less than 10% of the Total Other Production cost category is attributable to gas turbine units. Combined cycle units, which clearly represent the bulk of FPL's Other Production resources, were not intended to be included in Dr. Goins' proposed adjustment and, indeed, given their substantially different operating characteristics during periods other than the system peak, should not be included in any such adjustment. Thus, Dr. Goins calculations drastically overstate the impact from excluding the energy-related portion of gas turbines because he excludes both gas turbines and combined cycle units in his calculation.

Q. Why did Dr. Goins assume that the Other Production cost category consisted strictly of gas turbines?

A. In MFR E-6 a row heading which should have read "combined cycle and gas turbines" was inadvertently truncated as "gas turbines." While I regret any confusion this may have caused, it in no way altered the results of the cost of service study because the treatment of both gas turbines and combined cycle units is identical under FPL's proposed cost of service methodology. Given that there is no reason in that methodology for isolating the cost of gas turbines for a unique cost treatment, there was no way to predict that MFR E-6 would have been interpreted and used in the manner that Dr. Goins has interpreted it.

Q. **What impact did excluding the cost of combined cycle units have on Dr. Goins' proposed CILC energy charges?**

A. As I mentioned earlier, gas turbine units account for approximately less than 10% of Other Production plant in service. Thus, an adjustment designed to reflect the exclusion of gas turbine units would be only a small fraction of the amount Dr. Goins calculates.

Q. **Please summarize your conclusions regarding the testimony of Dr. Goins.**

A. My review of Dr. Goins' testimony has highlighted numerous inconsistencies and has shown how the proposed adjustment to the energy charge for the CILC rate classes has not been calculated correctly. Dr. Goins proposed adjustment should be rejected.

HIGH LOAD FACTOR TIME-OF-USE (HLFT) RATE

Q. **Please address Mr. Selecky's comment on page 26 of his testimony that a high load factor customer will generally be cheaper to serve than a customer with a lower load factor.**

A. Higher load factor customers may or may not be cheaper to serve than other customers depending on the type of cost in question. If we are looking at costs driven by localized peaks, such as distribution costs, then yes, high load factor customers are less expensive to serve on a per kWh basis. On the other hand, if we are considering costs driven by the system peak, then the cost of serving a customer depends on *timing* of their load. Many lower load factor customers contribute less to the system peak than do higher load factor customers by virtue of the fact that they are simply using electricity in fewer hours and therefore may not have substantial usage at the time of the system peak. In fact, a positive relationship between load factor and coincidence factor has long been recognized in ratemaking. In other words, higher load factor customers are more likely to be consuming at the time of the system peak than are lower load factor customers.

Q. How does the relationship between load factor and coincidence factor support FPL's proposed HLFT rate?

A. While there is the positive relationship between load factor and coincident factor, above a certain threshold increases in load factor are likely to be associated with progressively smaller increases in a customer's coincident factor. As illustrated in Document No. RM-16, this threshold occurs around a load factor of 70%. In addition, because the timing of a customer's load is critical, it is important that the HLFT rate encourage customers to maintain or increase their load factor only to the extent that kWh are added during the off-peak period. This is why the on-peak energy charge under the HLFT rate is significantly higher than the off-peak energy charge.

Q. On page 27 of his direct testimony, Mr. Selecky asserts that FPL's choice of a 70% load factor break-even calculation was arbitrary. Do you agree?

A. No. As described above, the decision to use a 70% load factor to calculate the break-even point was based on the load characteristics of the eligible rate classes. By contrast, the 65% load factor break-even calculation advocated by Mr. Selecky represents the average load factor for the rate class. Rather than recognizing higher than normal load factor usage, Mr. Selecky's proposed rate would reward customers with nearly average load factors.

Q. **Has the Commission previously approved optional rates based on load factor?**

A. Yes. There are numerous examples (Docket No. 74437-EU, Order No. 6650; Docket No. 920821-EM, Order No. PSC-92-1006-FOF-EM; Docket No. 020883-EC, Order No. PSC-02-1630-TRF-EC). In past cases, rates based on a threshold load factor of 70-75% have also been approved.

Q. **Do you agree with Mr. Selecky's assertion that FPL's choice of a 70% load factor break-even calculation was limiting?**

A. No. MFR E-13c shows 28% of the kWh sales from the eligible rate classes will qualify for the HLFT rate. In total, customers qualifying for and saving under the HLFT rate will represent 9.9 billion kWh. By any measure, this is far from limiting.

Q. **What is the revenue impact of providing a high load factor rate with a 70% break-even point?**

A. Use of a 70% break-even point results in total annual customer savings of approximately $17 million. Again, this is not the revenue impact one would associate with an offering of "limited" applicability.

Q. How would this revenue impact be altered by Mr. Selecky's proposed 65% load factor break-even point?

A. Use of a 65% break-even point would increase the revenue loss associated with the HLFT rate by almost 60%, to $27 million.

Q. Does Mr. Selecky suggest which customers should offset this additional revenue loss?

A. No.

Q. How would the added revenue loss – approximately $10 million – be recovered?

A. Clearly, the rates paid by other customers would have to increase to offset this revenue loss.

TURKEY POINT UNIT 5 ADJUSTMENT

Q. Please summarize your direct testimony with regard to the Turkey Point Unit 5 adjustment.

A. Consistent with the treatment of production plant in the 2006 test year I have allocated the plant cost of the Turkey Point Unit 5 on the basis of 12 CP and 1/13th and proposed an adjustment to the energy charges of each rate schedule to recover these costs.

Q. Have the intervenors addressed the proposed rate adjustments for Turkey Point Unit 5?

A. Yes. Mr. Baron (Direct Testimony, page 52, lines 4-11) and Mr. Selecky (Direct Testimony, page 29, lines 3-8) oppose the recovery of Turkey Point Unit 5 through kWh energy charges. However, as I have already demonstrated, kWh sales do a better job of tracking 12 CP than does billing kW. The vast majority of Turkey Point Unit 5 costs are allocated on the basis of 12 CP. Accordingly, the recovery of Turkey Point Unit 5 costs through the kWh energy charges is appropriate.

OVERVIEW OF COMMERCIAL RATES

Q. Are there any other issues regarding the Company's proposed rates you would like to address?

A. Yes. Mr. Selecky claims that electric rates are a significant measure of performance and that, by this measure, the Company's performance is not superior (Direct Testimony, page 5, lines 20-33). In support of this contention, Mr. Selecky manipulates data from the Edison Electric Institute (EEI) Typical Bills and Average Rates Reports for Summer 2004 (Summer Survey) and Winter 2005 (Winter Survey) to allegedly demonstrate that the Company's electric rates are in the top quartile of its peers.

Q. Do you believe Mr. Selecky's analysis is valid?

A. No. First of all, Mr. Selecky's analysis is based on total bill calculations which include fuel, clauses and taxes, items which are not at issue in this proceeding. In addition, Mr. Selecky limits his comparisons to electric utilities in the South, a region which according to EEI possesses among the lowest electric rates in the country. To further skew the analysis, Mr. Selecky does not simply average the results of the Summer Survey and Winter Survey but instead disproportionately weights the Winter Survey results.

Q. Please explain.

A. EEI reports a typical FPL 1,000 kWh residential bill of $86.43 and $89.92 for the Summer and Winter Surveys respectively. The arithmetic average of these two figures is $88.18 or 8.82 cents per kWh. Mr. Selecky, however, uses a figure of 8.88 cents for FPL. This figure appears to be the result of a seasonal weighting that places a 67% weight on the Winter Survey and a 33% weighting on the Summer Survey. Because FPL's sales during the summer months substantially exceed its winter sales, an argument could be made that if any weighting of the results is to be done, the heavier weight should be placed on the results of the Summer Survey. The only rationale for placing undue emphasis on the Winter Survey appears to be an effort to deflate the figures for other utilities, such as Progress North Carolina, which offer lower seasonal rates in the winter.

Q. What information can be drawn from the EEI reports in terms of the Company's rates versus those of other electric utilities?

A. Bear in mind that total bill comparisons, such as those reported by EEI, include fuel and other clauses which are not at issue in this proceeding. Nevertheless, the Company's residential rates are comparable to national averages based on the EEI reports. As shown in Document No. RM-17, the typical bills reported in the Summer Survey and the Winter Survey are, on average, less than the national typical bills reported for the same period. In light of the fact that almost 90% of the Company's customer base is residential, this is the most significant bill comparison that can be drawn from the EEI reports.

Q. What about the rates for commercial and industrial customers?

A. Following the same procedure of averaging the Winter Survey and Summer Survey results, the Company's typical commercial bills are comparable to the national averages while typical industrial bills are slightly higher.

Q. Does this mean that FPL's industrial customers are paying more on average than customers nationally while commercial customers are paying about the same as customers nationally?

A. I think it would be premature to draw that conclusion based strictly on the typical bill surveys. Because of the diversity of rate options available to them, typical bill comparisons are not as meaningful for commercial and industrial customers as they are for residential customers. For example, 20 out of FPL's 30 rate schedules are designed for commercial and industrial customers. The typical bill calculations reported for FPL in the EEI reports, however, are based strictly on standard general service demand rates. Customers taking advantage of time-of-use, curtailable service, and load control options would pay lower rates. In fact, a substantial percentage of FPL's eligible customers are doing just that. For example, 37% of commercial customers with demands of 500 kW or higher are on rate options not incorporated into the EEI typical bill calculations. The percentage of industrial customers with demands of 1,000 kW or higher is even more dramatic with 83% of those on rate options not incorporated into the EEI survey.

Q. What impact would these rate options have on the typical bill calculations of commercial and industrial customers?

A. As shown in Document No. RM-17, I have recalculated the typical bills reported for FPL using one of the rate options commercial and industrial customers are taking service under, CILC-1D. Based on the CILC-1D rate, FPL's typical bills for both commercial and industrial are lower than the national averages.

Q. CILC is sometimes viewed as an option limited to industrial customers. Do any commercial customers take service on CILC?

A. Absolutely. In fact, three quarters of FPL's CILC customers are commercial.

Q. Has anyone raised the rate options available to commercial customers as an issue in this case?

A. Yes. Ms. Civic and Mr. Galura in panel testimony for the Commercial Group claim that there have been few rate schedules tailored to the needs of their facilities.

Q. Is this assessment accurate?

A. No. The only way that their testimony would be accurate is if one focused exclusively on rate schedules tailored to the specific needs of the Commercial Group as a special discount which is available only to their members. On the other hand, however, if one defines a rate schedule "tailored to their needs" as an optional rate which similarly situated customers may elect, then FPL offers several rate schedules tailored to the needs of customers in the retail sector. Customers operating in the retail sector are taking service under a variety of FPL's rate options, including time-of-use, CILC, the Commercial/Industrial Demand Reduction (CDR)

Rider, and curtailable service. Moreover, the optional HLFT rate proposed by FPL will provide savings for a substantial number of customers in the retail sector, including those in the Commercial Group.

Q. Will all of the facilities represented by the Commercial Group qualify for the optional HLFT rate?

A. No. The facilities represented by the Commercial Group are not a homogeneous group, at least in terms of their load characteristics. Nonetheless, three of out four of the Commercial Group's members will have qualifying facilities. In fact, it appears that in some cases the vast majority of the customer's facilities will qualify based on the 70% load factor proposed by the Company. The facilities associated with the fourth customer within the Commercial Group have substantially lower load factors and will not qualify for the HLFT rate - nor would they qualify even based on the 65% load factor breakeven proposed by the Commercial Group. Given the lack of homogeneity within the Commercial Group's facilities it appears that designing a rate "tailored to the needs" of every facility they represent is not possible.

CONCLUSION

Q. Please summarize your rebuttal testimony.

A. The intervenors representing larger C/I customers have filed testimony proposing to allocate costs away from the customers they are representing and onto the residential and smaller commercial customers. The price tag for their proposals is high. Consider, for example, just two of the recommendations of the Commercial Group, the use of the 150% rule-of-thumb and a 65% load factor threshold for the HLFT rate. In combination, these two proposals alone would allocate an additional $28 million to smaller customers. The use of cost of service methodologies not supported by Commission precedent, but advocated by intervenors in this case, would surely add to this figure. The Commission should reject the proposals by intervenors to alter the cost of service methodologies and rate design as proposed by FPL.

Q. Does this conclude your testimony?

A. Yes

ERRATA SHEET

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

PAGE #	LINE #	CHANGE
47	8	The first "of" should be moved after the word "out."

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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