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

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June 24, 2005

Director
Division of the Commission Clerk
FL PSC
2540 Shumard Oak Blvd
Tallahassee, Fl 32399-0850

Dear Sir or Madam,

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

Sincerely

Craig Paulson

CRAIG PAULSON, Major, USAF

AFCESA/ULT
139 Barnes Drive
Tyndall Air Force Base, Florida 32403
Ph: 850-283-6350; Fax: 850-283-6219
E-mail: craig.paulson@tyndall.af.mil
TX Atty #24030340
MN Atty# 0164823

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STATE OF FLORIDA
BEFORE THE
PUBLIC SERVICE COMMISSION

DOCKET NO. 050045-EI

RE: PETITIONS FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY

**DIRECT TESTIMONY OF
DR. DENNIS W. GOINS
ON BEHALF OF THE
FEDERAL EXECUTIVE AGENCIES**

June 27, 2005

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BEFORE THE
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INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Dennis W. Goins. I operate Potomac Management Group, an economics and management consulting firm. My business address is 5801 Westchester Street, Alexandria, Virginia 22310.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Ph.D. degree in economics and a Master of Economics degree from North Carolina State University. I also earned a B.A. degree with honors in economics from Wake Forest University. From 1974 through 1977 I worked as a staff economist at the North Carolina Utilities Commission. During my tenure at the Commission, I testified in numerous cases involving electric, gas, and telephone utilities on such issues as cost of service, rate design, intercorporate transactions, and load forecasting. While at the Commission, I also served as a member of the Ratemaking Task Force in the national Electric Utility Rate Design Study sponsored by the Electric Power Research Institute (EPRI) and the National Association of Regulatory Utility Commissioners (NARUC).

Since 1978, I have worked as an economic and management consultant to firms and organizations in the private and public sectors. My assignments focus primarily on market structure, planning, pricing, and policy issues involving firms that operate in energy markets. For example, I have conducted detailed analyses of product pricing, cost of service, rate design, and interutility planning, operations, and pricing; prepared analyses related to utility mergers, transmission access and pricing, and the emergence of competitive markets; evaluated and developed regulatory incentive mechanisms applicable to utility operations; and assisted clients in analyzing and negotiating interchange agreements and power and fuel supply contracts. I have also assisted clients on electric power market restructuring issues in Arkansas, New Jersey, New York, South Carolina, Texas, and Virginia.

I have participated in more than 100 proceedings before state and federal agencies as an expert in cost of service, rate design, utility planning and operating practices, regulatory policy, and competitive market issues. These agencies include the Federal Energy Regulatory Commission (FERC), the General Accounting Office, the Circuit Court of Kanawha County, West Virginia, the First Judicial District Court of Montana, and regulatory agencies in Arkansas, Arizona, Colorado, Georgia, Illinois, Kentucky, Louisiana, Maine, Massachusetts, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, and the District of Columbia. A summary of my professional qualifications and case participation is shown in Exhibit No.___(DWG-2).

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Federal Executive Agencies (FEA), which is comprised of all Federal facilities served by Florida Power & Light Company (FPL). Some of the largest FEA facilities include Patrick Air Force Base, Cape Canaveral Air Station, and the Kennedy Space Center. FPL currently serves these facilities under different commercial and industrial rate schedules.

Q. WHAT ASSIGNMENT WERE YOU GIVEN WHEN YOU WERE RETAINED?

A. I was asked to undertake two primary tasks:

1. Review FPL's proposed cost-of-service analyses and related rates.
2. Identify any major deficiencies in the cost analyses and proposed rates and suggest recommended changes.

Q. WHAT SPECIFIC INFORMATION DID YOU REVIEW IN CONDUCTING YOUR EVALUATION?

A. I reviewed FPL's application, testimony, exhibits, and responses to requests for information and production of documents. I also reviewed documents and information found on web sites operated by the Commission and FPL.

CONCLUSIONS

Q. WHAT CONCLUSIONS HAVE YOU REACHED?

A. On the basis of my review and evaluation, I have concluded the following regarding FPL's cost-of-service analyses and proposed interruptible service options:

1. Classification and allocation of demand-related generation and transmission costs. In this case, FPL has proposed classifying all generation and transmission plant costs (except for transmission pull-offs required to connect transmission customers to the grid) using the 12 CP and $1/13^{th}$ methodology. Under this methodology, FPL classifies approximately 92 percent (12/13) of these costs as demand-related costs and the remaining 8 percent (1/13) as energy-related costs. FPL allocates the demand-related costs to customer classes using the 12 CP methodology—that is, the contribution of each class to FPL's 12 monthly coincident system peaks during the test year. FPL allocates the energy-related costs to customer classes using kWh sales adjusted for losses. The Florida Commission has approved the 12 CP and $1/13^{th}$ methodology in prior FPL rate cases, and even requires utilities to use the methodology in filing a rate increase application under the Commission's Minimum Filing Requirements (MFRs).

2. Revenue Spread. FPL notes that in past cases the Commission has adopted a rule-of-thumb for revenue spread that limits a customer class' base rate increase to no more than 150 percent of the system average increase and restricts any class from receiving a rate decrease. In this case, FPL has abandoned this rule-of-thumb and instead proposed moving each class's rate of return to within 10 percent of the system average rate of return (that is, to a rate of return index between 90 and 110), but to ensure that the base rate increase to no class exceeds 25 percent. As a result of FPL's revenue spread decision, customers served under several of FPL's proposed rate schedules will receive base rate increases exceeding

the Commission's rule-of-thumb limiting increases to 150 percent of the system average increase.

3. Commercial/Industrial Load Control (CILC) Rate. Under FPL's CILC program, customers can buy interruptible[1] (nonfirm) service if they are willing to curtail (through active load reductions) or displace (through on-site generation) at least 200 kW of load during peak periods when requested by FPL. In exchange for agreeing to interrupt load during peak periods, customers pay a discounted price for their nonfirm (that is, Load Control) loads. Part of this price discount reflects FPL's demand-related unit cost of gas turbine production capacity assigned to each customer class. However, the price discount does not reflect the energy-related unit cost of gas turbine production capacity assigned to each customer class. In this case, FPL has proposed major increases in the Load Control On-Peak Demand charge in its CILC rates ranging from 52 percent to 58 percent.[2] At the same time, FPL has proposed reducing the energy charges for secondary and primary distribution CILC customers, while increasing the energy charge for CILC customers served at transmission.

RECOMMENDATIONS

Q. WHAT DO YOU RECOMMEND ON THE BASIS OF THESE CONCLUSIONS?

A. I recommend that the Commission:

1. Approve FPL's 12CP and 1/13th allocation methodology. As FPL notes, the Commission has approved the 12CP and 1/13th

[1] In my testimony I use *interruptible* and *curtailable* interchangeably in discussing nonfirm service.
[2] See MFR Schedule A-3, page 7.

methodology in previous rate cases for FPL and other utilities in Florida. I prefer an allocation methodology that reflects only the principal factors—coincident peak demands—driving the need for generation and transmission capacity. However, in this case I find no compelling reason to reject FPL's recommended 12CP and $1/13^{th}$ methodology, particularly given the Commission's past support.

2. Reject FPL's proposed revenue spread. Instead, the Commission should require FPL to spread its proposed revenue increase such that no rate receives an increase greater than 150 percent of the average system increase. This so-called rule-of-thumb revenue spread moves each class closer to cost of service without the unacceptably high base rate increases imposed on some classes under FPL's proposed spread.

3. Reject the proposed energy charges in FPL's proposed CILC rates. Instead, as shown later in my testimony, the proposed energy charges should be reduced by the appropriate energy-related unit cost of gas turbine production capacity assigned to CILC-1G, CILC-1D, and CILC-1T customers. This adjustment is necessary to:
   - Reflect the role of the CILC program in reducing capacity requirements during peak periods.
   - Be consistent with excluding demand-related unit costs of gas turbine production capacity in the CILC Load Control On-Peak demand charges.

COST OF SERVICE

Q. DID FPL CONDUCT A RETAIL CLASS COST-OF-SERVICE STUDY IN DEVELOPING ITS PROPOSED RATES?

A. Yes. In developing its proposed retail rates for this case, FPL first conducted a detailed cost-of-service study using data (adjusted in many cases) for the test year ending December 31, 2006. In this cost analysis, FPL allocated and/or directly assigned its retail jurisdictional costs to functional segments of its retail electric business, and then allocated and/or directly assigned these costs to its major customer classes. FPL then used these class costs to develop its proposed rates.

Q. IS THE COST-OF-SERVICE STUDY THAT FPL CONDUCTED REASONABLE?

A. Yes. The cost study generally follows guidelines in the NARUC *Electric Utility Cost Allocation Manual*.[3]

Q. WHY IS THE REASONABLENESS OF A COST-OF-SERVICE METHODOLOGY IMPORTANT?

A. Cost of service identifies and assigns cost responsibility to customer classes. Specific rates can then be developed to recover each class' cost-based revenue requirement, resulting in prices that recover the utility's cost of service in an equitable and efficient manner. If the 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—thereby causing customers to make inefficient electricity investment and consumption decisions. In my opinion, FPL has employed a reasonable cost-of-service

[3] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation*

methodology in this case to allocate and assign its production and transmission plant costs to customer classes.

Q. HOW DID FPL CLASSIFY ITS PRODUCTION AND TRANSMISSION CAPACITY COSTS AND ALLOCATE THEM TO CUSTOMER CLASSES?

A. In this case, FPL classified its production and transmission plant costs (except for transmission pull-offs required to connect transmission customers to the grid) using the 12 CP and 1/13th methodology. Under this capital substitution methodology, most (approximately 92 percent or 12/13) of these costs was first classified as demand-related costs, while the remainder (8 percent or 1/13) was classified as energy-related costs. FPL then allocated the demand-related costs to customer classes using the 12 CP methodology, which reflects each class' contribution to FPL's 12 monthly coincident system peaks during the test year. FPL next allocated the energy-related costs to customer classes using kWh sales adjusted for losses.

Q. IS THE 12CP AND 1/13TH METHODOLOGY DISCUSSED IN THE NARUC COST MANUAL?

A. Yes. The method FPL chose to classify and allocate production and transmission capacity costs is one of several capital substitution methodologies discussed in the NARUC cost manual.[4]

Manual, Washington, DC, January 1992.

[4] For the specific discussion of the 12CP and 1/13th methodology, see the NARUC cost manual at pages 58-59.

Q. DO YOU SUPPORT FPL'S CHOICE OF THIS CLASSIFICATION AND ALLOCATION METHODOLOGY?

A. I do not support capital substitution classification and allocation methodologies—including FPL's 12CP and 1/13th methodology. I generally prefer a fixed/variable approach to classify production and transmission plant costs, and an allocation methodology that emphasizes coincident peak demands as the principal factors driving the need for generation and transmission capacity. However, the 12CP and 1/13th methodology is probably one of the least objectionable of the capital substitution methodologies, and it is recognized as an acceptable costing approach in the NARUC cost manual. In addition, according to FPL, the Commission has approved the 12CP and 1/13th methodology in past rate cases involving FPL and other utilities in Florida. As a result, replacing the 12CP and 1/13th methodology should be considered only if another costing approach clearly provides a more compelling linkage between customer demands and FPL's bulk power system costs.

Q. SHOULD THE COMMISSION ADOPT FPL'S 12CP AND 1/13TH METHODOLOGY?

A. Yes. In my opinion, FPL's recommended 12CP and 1/13th methodology provides a reasonable compromise for classifying and allocating demand-related generation and transmission costs. As I noted earlier, I prefer methodologies that focus on class contributions to system peak demands. However, FPL's 12CP and 1/13th methodology represents a middle ground between methodologies that emphasize peak demand (which I prefer) and those that rely primarily on energy measures to develop demand allocation factors. Because it recognizes both demand and energy factors, FPL's 12CP and 1/13th methodology can be seen as a reasonable compromise between peak demand costing advocates and energy-only costing advocates.

REVENUE SPREAD

Q. HOW DID FPL SPREAD ITS PROPOSED RATE INCREASE?

A. In this case, FPL has used a 2-step approach to spread its proposed rate increase:

- Move each class' rate of return to within 10 percent of the system average rate of return (that is, to a rate of return index between 90 and 110),
- Limit any class' maximum base rate increase to 25 percent.

Q. IS FPL'S PROPOSED REVENUE SPREAD CONSISTENT WITH PAST COMMISSION PRACTICE?

A. No. FPL notes that in past cases the Commission has adopted a rule-of-thumb for revenue spread that limits a customer class' base rate increase to no more than 150 percent of the system average increase and restricts any class from receiving a rate decrease.

Q. DOES FPL'S PROPOSED REVENUE SPREAD PRODUCE UNACCEPTABLE RATE INCREASES FOR SELECTED CUSTOMERS?

A. Yes. As a result of FPL's revenue spread decision, customers served under several of FPL's proposed rate schedules will receive base rate increases exceeding the Commission's rule-of-thumb limiting increases to 150 percent of the system average increase. More specifically, under

FPL's proposed revenue spread, seven rates are increased more than 20 percent, while three rates get the maximum 25-percent increase.[5]

Q. IS FPL'S PROPOSED REVENUE SPREAD NECESSARY TO MOVE RATES SIGNIFICANTLY CLOSER TO COST OF SERVICE?

A. No. FPL's witness Rosemary Morley's testimony demonstrates that rates for all classes can be moved significantly closer to cost of service simply by using the Commission's 150 percent rule-of-thumb revenue spread.[6] In my opinion, moving rates closer to cost of service without resorting to 25-percent rate increases for some classes limits the chance of rate shock and is consistent with the generally accepted ratemaking principle of gradualism.

Q. SHOULD THE COMMISSION REJECT FPL'S PROPOSED REVENUE SPREAD?

A. Yes. FPL's proposed revenue spread reflects a good faith effort to move rates closer to cost of service. However, FPL's revenue spread produces unacceptably high rate increases for selected customers. I recommend a more gradual—but significant—movement toward this cost-of-service goal using the Commission's 150 percent rule-of-thumb revenue spread.

INTERRUPTIBLE SERVICE

Q. WHAT IS INTERRUPTIBLE OR NONFIRM SERVICE?

A. Interruptible service is a separately identifiable utility product that allows a supplier to interrupt or curtail customer loads when reliability is impaired. Interruptible load enables a supplier to maximize the value of its existing

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[5] See MFR Schedule E-8.

[6] Rosemary Morley, direct testimony, Document No. RM-6, page 1.

reserve capacity and to avoid installing new capacity. The available supply of interruptible service depends on the relationship between available capacity and firm service demands. That is, if firm demands command all available generating capacity, the supply of interruptible service falls to zero. When firm demands are significantly less than available capacity, the supply of interruptible service is significantly greater. Interruptible service can only be produced and sold by the utility supplier. End-use customers are the buyers of interruptible service—not the suppliers.

Q. DOES FPL OFFER INTERRUPTIBLE SERVICE TO COMMERCIAL AND INDUSTRIAL CUSTOMERS UNDER ITS CURRENT RATES?

A. Yes. FPL currently offers interruptible service to customers that can interrupt at least 200 kW of load when requested by FPL. FPL's interruptible service options include Rate Schedules CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, and CILC-1, plus Rider CDR. These rates and rider incorporate either explicit billing demand discounts (the CS, CST, and CDR options) or implicit discounts reflected in a reduced price for interruptible demand (the CILC option).

Q. DOES FPL DERIVE BENEFITS FROM INTERRUPTIBLE CUSTOMERS?

A. Yes. By excluding interruptible load from its peak-load capacity requirements, FPL achieves capacity-cost savings by not having to build capacity to serve the interruptible load. The avoided capacity includes not only capacity required to serve the interruptible load, but also reserve capacity that would have been built to provide reliability if interruptible customers had chosen firm service.[7] Capacity-cost savings attributable to interruptible load break down into two major categories associated with the avoided capacity:

- Avoided fixed costs. These include capital costs (including return), insurance, interest, taxes, and fixed nonfuel operation and maintenance (O&M) expense.
- Avoided variable costs. These include fuel and variable O&M expense.

Q. DOES INTERRUPTIBLE LOAD OFFER BENEFITS RELATIVE TO COMBUSTION TURBINE CAPACITY?

A. Yes. First, environmental impacts of constructing and operating combustion turbines are avoided if interruptible load displaces the need for such capacity. Second, selling interruptible service reduces a utility's short- and long-term financial investment risk relative to building capacity to serve an equivalent amount of firm service. For example, remaining customers may be forced to absorb stranded generation investment costs associated with the loss of a large firm-service load. Such costs cannot occur if an interruptible customer leaves the system.

Q. SHOULD AN INTERRUPTIBLE RATE RECOVER ANY EMBEDDED OR FIXED PRODUCTION AND TRANSMISSION COSTS?

A. No. Fundamental economic theory demonstrates that interruptible customers do not cause the utility to incur embedded production and bulk transmission costs. For example, Professor James C. Bonbright, a

[7]Under certain conditions, a utility can use interruptible load to meet not only part of its installed reserve requirement, but also part of its operating reserve requirement.

recognized pricing authority, advocated pricing interruptible service to reflect no capacity-related cost of service:

> Interruptible service has been used by both gas and electric companies for peak shaving. The costs cannot be accurately determined because it is a byproduct resulting from generating and bulk transmission facilities built and operated for firm service (see Nissel, 1983). As a result, only the customer cost (e.g., customer-connected spur lines and substations) and energy costs (e.g., fuel and incremental maintenance cost) actually incurred and ***no capacity pricing cost should be included in pricing interruptible service***.
>
> While some feel that it is an impropriety to treat interruptible customers as if they were firm customers, they still opine that it would be fair and reasonable to obtain a small contribution from them for capacity costs. This is debatable.[8] (Emphasis added.)

Q. ARE INTERRUPTIBLE CUSTOMERS "FREE RIDERS" IF THEY PAY NO DEMAND-RELATED PRODUCTION COSTS?

A. No. As noted by Professor Bonbright, eliminating all or most embedded fixed-cost recovery may raise fallacious but politically attractive "free rider" arguments. As a result, most electric rates for interruptible service are designed to recover a portion of the utility's fixed production and bulk transmission costs. However, under an efficient pricing scheme, customers should only pay for costs attributable to their demands. Since a utility is not required to build or acquire generating or transmission capacity to serve interruptible load, only firm service customers should pay

[8] James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, *Principles of Public Utility Rates*, Arlington, Virginia: Public Utilities Reports, Inc., 1988, page 502.

for the demand-related costs of this capacity. If interruptible rates recover part of the fixed costs of capacity built to serve only firm loads, then interruptible customers cannot be "free riders."

Q. DOES FPL PRICE ITS INTERRUPTIBLE SERVICE ON THE BASIS OF EMBEDDED OR MARGINAL COST OF SERVICE?

A. Prices reflected in FPL's current rates are based on embedded costs used in its cost-of-service analyses, and reflect either explicit billing demand discounts or implicit discounts reflected in a reduced price relative to firm service. Because the discounts are below stated billing demand charges for firm service, FPL ensures that interruptible customers make a major contribution to recovery of its fixed production and/or transmission costs.

Q. IS THE VALUE OF INTERRUPTIBLE LOAD REDUCED IF FPL DOES NOT INTERRUPT ALL INTERRUPTIBLE CUSTOMERS DURING SYSTEM PEAKS?

A. No. Interruptible load has both long- and short-term value. As I noted earlier, its long-term value is reflected in the capacity-cost savings (including the cost of planning reserves) that a utility avoids. Its short-term value is reflected in the operating reserve and system reliability benefits, fuel cost savings, variable O&M savings, and system losses that a utility avoids. The relevant issue is FPL's right to interrupt load—not whether the load is actually interrupted.

Q. ARE ANY FEA CUSTOMERS SERVED UNDER FPL'S INTERRUPTIBLE SERVICE OPTIONS?

A. Yes. At least one account for each of the major FEA customers I noted earlier is served at transmission voltage under Rate CILC-1T. These FEA customers began taking service under Rate CILC-1T before FPL closed the rate to new customers in 2000.

Q. UNDER WHAT CONDITIONS CAN FPL INTERRUPT CILC CUSTOMERS?

A. Under Rate CILC, FPL can interrupt load whenever an interruption is necessary to:

- Alleviate a power supply or transmission emergency condition or capacity shortage.
- Keep FPL from operating its generators above their continuous rated output.

Q. HAS FPL PROPOSED A MAJOR INCREASE IN THE CILC RATES?

A. Yes. In this case, FPL has proposed major increases for Rates CILC-1D and CILC-1T. These increases are due primarily to FPL's proposed increases—ranging from 52 percent to 58 percent—in the Load Control On-Peak Demand charge in its CILC rates.[9] At the same time, FPL has proposed reducing the energy charges for secondary and primary distribution CILC customers, while increasing the energy charge for CILC customers served at transmission.

Q. DO YOU AGREE WITH HOW FPL HAS PRICED CILC INTERRUPTIBLE SERVICE?

A. In general, I do agree. In particular, FPL's decision to exclude demand-related unit production costs from Rate CILC's Load Control On-Peak demand charge is consistent with Professor Bonbright's recommended interruptible pricing strategy. However, under FPL's 12CP and 1/13th

methodology, part of the capacity costs of gas turbine production capacity is classified as energy and reflected in the unit energy costs for the CILC rates. As a result, CILC customers avoid paying demand-related gas turbine production costs incurred to meet peak loads, but are required to pay the energy-related gas turbine production costs through the CILC energy charges.

Q. SHOULD THE ENERGY-RELATED COMPONENT OF GAS TURBINE PRODUCTION COSTS BE EXCLUDED FROM THE CILC ENERGY CHARGES?

A. Yes. 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 from the CILC Load Control On-Peak demand charges.

Q. WHAT CILC ENERGY CHARGES WOULD RESULT IF YOUR RECOMMENDATION WERE ADOPTED?

A. The CILC energy charge applicable to a customer's firm load would remain unchanged from FPL's proposed energy charge.[10] However, the energy charge applicable to CILC nonfirm loads would be reduced by the estimated energy-related gas turbine production costs included in FPL's proposed energy charge. The resulting energy charges following this adjustment to Rates CILC-1G, CILC-1D, and CILC-1T are shown in Exhibit No.___(DWG-1).

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[9] See MFR Schedule A-3, page 7.

[10] This statement assumes that the Commission approves FPL's requested revenue level and cost allocation to CILC customers.

Q. HOW WOULD FPL IMPLEMENT YOUR RECOMMENDED ENERGY CHARGE MODIFICATION IN BILLING CILC CUSTOMERS?

A. If a CILC customer's total load is interruptible, the CILC energy charge would simply be the applicable adjusted energy charge shown in Exhibit No.___(DWG-1). If a CILC customer has a specified firm load, the firm component of a customer's monthly kWh usage would equal the firm demand at a 100 percent load factor. This firm kWh component would be billed at FPL's proposed CILC energy charge. All remaining kWh would be considered Load Control (nonfirm) kWh and billed at the applicable adjusted energy charge.

Q. WHAT WOULD BE THE MAXIMUM REVENUE IMPACT OF YOUR RECOMMENDED ENERGY CHARGE MODIFICATION?

A. As shown in Exhibit No.___(DWG-1), the maximum revenue impact would be approximately $2 million. However, this impact would be significantly less since the recommended energy charge modification would only be applicable to the nonfirm component of a CILC customer's monthly kWh usage.

Q. SHOULD THE COMMISSION APPROVE RATE SCHEDULE CILC AS FILED?

A. No. The Commission should require FPL to implement my recommended adjustment to the CILC energy charge applicable to a customer's nonfirm load.

Q. SHOULD THE SAME ENERGY CHARGE MODIFICATION BE MADE IN FPL'S OTHER INTERRUPTIBLE RATE OPTIONS?

A. I am not sure that such a modification is necessary. Unlike Rate CILC, FPL's CS and CST rates and CDR rider incorporate explicit demand charge discounts to applicable firm service rates. FPL's filing contains no information showing how these explicit demand charge discounts were derived. As a result, at this time I am not recommending modifications to energy charges in the CS, CST, and CDR options similar to the energy charge modification I have recommended for the CILC option.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

Docket No. 050045-EI
Witness: Dennis W. Goins
Exhibit No._____(DWG-1)
Page 1 of 1

Remove Energy-Related Gas Turbine Production Costs

		Rate Schedule		
		CILC-1G	CILC-1D	CILC-1T
Proposed	Peak-kWh	$ 0.007760	$ 0.006300	$ 0.005400
	Off-kWh	$ 0.007760	$ 0.006300	$ 0.005400
GT Unit Cost	Peak-kWh	$ (0.000435)	$ (0.000431)	$ (0.000417)
	Off-kWh	$ (0.000435)	$ (0.000431)	$ (0.000417)
Adjusted Energy Chrg	Peak-kWh	$ 0.007325	$ 0.005869	$ 0.004983
	Off-kWh	$ 0.007325	$ 0.005869	$ 0.004983
kWh	Peak-kWh	62,066,865	808,142,709	374,002,543
	Off-kWh	167,578,073	2,236,311,862	1,099,026,134
Base Rev Adj	Peak-kWh	$ (26,999)	$ (348,310)	$ (155,959)
	Off-kWh	$ (72,896)	$ (963,850)	$ (458,294)
	Total	$ (99,896)	$ (1,312,160)	$ (614,253)
	Total Adj	$(2,026,308)		

Sources:
MFR E-6b
MFR E-13c

Docket No. 050045-EI
Witness: Dennis W. Goins
Exhibit No._____(DWG-2)

QUALIFICATIONS OF

DENNIS W. GOINS

DENNIS W. GOINS

PRESENT POSITION

Economic Consultant, Potomac Management Group, Alexandria, Virginia.

AREAS OF QUALIFICATION

- Competitive Market Analysis
- Costing and Pricing Energy-Related Goods and Services
- Utility Planning and Operations
- Litigation Analysis, Strategy Development, Expert Testimony

PREVIOUS POSITIONS

- Vice President, Hagler, Bailly & Company, Washington, DC.
- Principal, Resource Consulting Group, Inc., Cambridge, Massachusetts.
- Senior Associate, Resource Planning Associates, Inc., Cambridge, Massachusetts.
- Economist, North Carolina Utilities Commission, Raleigh, North Carolina.

EDUCATION

College	Major	Degree
Wake Forest University	Economics	BA
North Carolina State University	Economics	ME
North Carolina State University	Economics	PhD

RELEVANT EXPERIENCE

Dr. Goins specializes in pricing, planning, and market structure issues affecting firms that buy and sell products in electricity and natural gas markets. He has extensive experience in evaluating competitive market conditions, analyzing power and fuel market operations and transactions, developing product pricing strategies, setting rates for energy-related products and services, negotiating power supply and natural gas contracts for private and public entities, and forecasting power requirements and fuel prices. He has participated in more than 100 cases as an expert on competitive market issues, utility restructuring, power market planning and operations, utility mergers, rate design, cost of service, and management prudence before the Federal Energy Regulatory Commission, the General Accounting Office, the First Judicial District Court of Montana, the Circuit Court of Kanawha County, West Virginia, and regulatory commissions in Arkansas, Arizona, Colorado, Georgia, Illinois, Kentucky, Louisiana, Maine, Massachusetts, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, and the District of Columbia. He has also prepared an expert report on behalf of the United States regarding pricing and contract issues in a case before the United States Court of Federal Claims.

PARTICIPATION IN REGULATORY, ADMINISTRATIVE, AND COURT PROCEEDINGS

1. Arkansas Electric Cooperative Corporation, before the Arkansas Public Service Commission, Docket No. 04-141-U (2005), on behalf of Nucor Steel and Nucor-Yamato Steel, re cost-of-service and rate design issues.
2. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 412 (2005), on behalf of Nucor Steel-Hertford, re cost-of-service and rate design issues.
3. Public Service Company of Colorado, before the Colorado Public Utilities Commission, Docket No. 04S-164E (2004), on behalf of the U.S. Air Force (United States Executive Agencies), re cost-of-service and rate design issues.
4. PacifiCorp, before the Utah Public Service Commission, Docket No. 04-035-42 (2004), on behalf of the U.S. Air Force (United States Executive Agencies), re cost-of-service and rate design issues.
5. CenterPoint Energy Houston Electric, LLC, *et al.*, before the Public Utility Commission of Texas, PUC Docket No. 29526 (2004), on behalf of the Coalition of Commercial Ratepayers, re stranded cost true-up balances.
6. Idaho Power Company, before the Idaho Public Utilities Commission, Case No. IPC-E-03-13 (2004), on behalf of the United States Department of Energy (Federal Executive Agencies), re retail cost allocation and rate design issues.
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