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In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	**CASE NO. 2011-00162**

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1. Provide the names of each member of the KIUC that in fact is represented by KIUC in Case Nos. 2011-00161 and 2011-00162.

RESPONSE:

Arch Chemicals, Inc.
Cemex
Clopay Plastics Products Co., Inc.
Corning Incorporated
Dow Corning Corporation
E.I. DuPont de Nemours & Company
Ford Motor Company
Lexmark International, Inc.
GE – Appliance Park
MeadWestvaco
NewPage Corp.
North American Stainless
Schneider Electric USA
Toyota Motor Engineering & Mfg. NA, Inc.

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2. Please provide all data, assumptions and calculations in Excel format with formulas intact for each of the Baron Exhibits SJB-2 through SJB-6.

RESPONSE:

Please see attached compressed file: "Baron Workpapers.zip."

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3. Provide a detailed description of all changes that would need to be made to LG&E's [or KU's] tariff to implement Mr. Baron's proposal.

RESPONSE:

Please see response to Question No. 10. The tariff would be modified by adding additional steps to implement the additional calculations described in the response to Question No. 10. This would include calculations of E(m) values for the non-C&I and C&I rate groups using each rate group's (non-C&I and C&I) "Base Revenues," the calculation of the non-C&I Environmental Surcharge billing factor by dividing the non-C&I E(m) by the non-C&I base revenues and the C&I Environmental Surcharge billing factor by dividing the C&I E(m) by the C&I non-fuel base revenues.

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4. Provide a detailed description of all changes that would need to be made to the monthly ECR forms submitted by LG&E [or KU] to implement Mr. Baron's proposal.

RESPONSE:

Please see response to Question No. 10.

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5. Refer to Page 7, lines 12 through 15 of Mr. Baron's testimony where he says:

> "Because the majority of ECR revenue requirements are fixed costs that are unrelated to energy use or the level of the Companies' fuel expenses, it is not appropriate to apply the environmental surcharge to customers on the basis of fuel expenses."

Given this assertion, explain why it is appropriate to allocate ECR expenses between C&I customers and non-C&I customers based on total revenue rather than using net revenue for all classes?

RESPONSE:

From a pure cost of service perspective, Mr. Baron believes that it would be appropriate to use net revenues rather than total revenues for all classes. However, in consideration of gradualism and rate impact on smaller non-C&I customers, including residential customers, Mr. Baron is only proposing to modify the allocation of ECR expenses among C&I rate classes.

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6. Please provide any work papers or support documents for Mr. Baron's Table No. 1 at page 9 of his testimony.

RESPONSE:

Please see workpapers provided in response to Question No. 2.

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7. Please explain how Mr. Baron's proposal would affect high-load-factor customers served on the General Service Rate Schedule.

RESPONSE:

Since customers on the General Service Rate Schedule are not billed on a demand metered basis, but only on a kWh basis, there is no recognition of load factor differences among GS customers. Because, on average, GS customers have a lower load factor than all C&I customers as a group, Mr. Baron would expect that high load factor GS customers would pay a higher ECR charge under his proposal. Baron Exhibit__(SJB-6) provides typical bill impacts for GS customers.

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8. Refer to the Direct Testimony of Stephen Baron page 12. Please explain why Rate Schedule GS (which does not have a demand charge component) is being treated differently that the other rate schedules that do not have a demand charge component under the proposed methodology by the KIUC.

RESPONSE:

As explained in Mr. Baron's testimony, and in response to Question No. 5, it would be appropriate from a pure cost of service basis to allocate ECR revenue requirements to each rate schedule, including Schedule GS, on a non-fuel base revenue basis. Mr. Baron's proposal is to mitigate the impact on non-C&I customers (e.g., residential, all-electric schools, etc.). Since customers on Schedule GS are business customers, Schedule GS should be included in the "C&I" rate group.

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9. Given that there may be customers who are served on residential rate ("RS"), Volunteer Fire Department ("VFD"), Lighting ("LE, "St. LT and P.O. Lt."), Traffic Energy ("TE") and All Electric Schools ("AES") that have load factors similar to the above-average load factor C&I customers, should such customers also be allocated ECR charges by removing fuel revenue from the ECR allocator for such customers?

RESPONSE:

No. The purpose of Mr. Baron's proposal is to maintain the current ECR allocation among non-C&I customers, such that these customers would be unaffected by the KIUC proposal.

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10. Refer to the Direct Testimony of Stephen Baron page 13. Under the KIUC's proposals there would be two different ECR billing factors for each month.
    a. How would the KIUC propose to determine the two monthly ECR billing factors in the monthly ECR filings with the Commission?
    b. How would the KIUC propose to determine the actual over/(under) recovery position during the review periods?
    c. How would the KIUC propose to perform a roll-in to base rates during the 2-year review proceedings?

<u>RESPONSE</u>:

a. Separate ECR factors would be calculated each month following the methodology used in Mr. Baron's exhibits and workpapers. Step 1 would allocate the monthly ECR revenue requirement among the designated non-C&I and C&I rate groups using base revenues. Step 2 would separately remove the non-C&I and C&I "Revenue Collected through Base

Rates." The result would be a separate "Net Jurisdictional E(m)" for the non-C&I rate schedules and the C&I rate schedules. The resulting non-C&I ECR factor would be identical to the current factor produced by the Companies' ECR adjustment clause and be calculated in the same manner that is currently used by the Companies in their monthly ECR filings.

For the C&I rate schedules, a ratio would be developed of 1) the remaining "ECR revenue requirement less the amount collected through base rates" to 2) the non-fuel base revenues based on the average monthly base revenues ending with the current month of the rate schedules comprising the C&I rate group identified by Mr. Baron in his

Exhibit__(SJB-2). The resulting non-fuel base revenue ECR factor for C&I customers would be applied to each customer's monthly non-fuel base revenues.

b. Mr. Baron would propose that any necessary prior period adjustment by made to the total ECR revenue requirement each month, prior to the allocation between non-C&I and C&I customers.

c. Mr. Baron would recommend that the base rate roll-in follow the existing methodology except that an additional step would be added to the calculations to first allocate the roll-in amount to non-C&I and C&I rate schedule groups on the basis of total revenues excluding ECR revenues (the current method). For non-C&I rate schedules, the allocated

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roll-in total would be spread to rate schedules following the current methodology that use total revenues excluding ECR. For the C&I rate schedules, the allocated C&I roll-in amount would be allocated to rate schedules on the basis of total revenues excluding ECR and FAC in base revenues. The resulting roll-in would then be assigned to rate schedules and rate elements in the same manner as is currently used by the Companies.

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11. Refer to the Direct Testimony of Stephen Baron page 15 and Baron Exhibit SJB-6. Please provide the calculations for Rate Schedule FLS in the same manner as provided for all other Rate Schedules.

RESPONSE:

See attached file.

KU Billing Analysis
August 2011 Base Rates*

		Incremental ECR Charges											
Monthly kW	Monthly kWh	2012 KU As-Filed	2012 KIUC	2012 Difference $	2012 Difference % Total Bill	2014 KU As-Filed	2014 KIUC	2014 Difference $	2014 Difference % Total Bill	2016 KU As-Filed	2016 KIUC	2016 Difference $	2016 Difference % Total Bill
FLS		$ 22,766.50	$ 19,545.75	$ (3,220.75)	-0.2%	$ 128,700.44	$ 119,986.99	$ (8,713.45)	-0.5%	$ 189,411.12	$ 180,140.04	$ (9,271.08)	-0.6%

* Average Summer/Winter Demand Charge
FAC and ECR Surcharges Average for 12 Months Ended August 2011
Assumes Base Fuel is identical for all rate schedules

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12. Refer to the Direct Testimony of Lane Kollen page 4 line 20 through page 5 line 1. Provide the calculation of the referenced $161 million and $225 million in savings for KU and LG&E customers, respectively. Provide all data, assumptions and calculations in Excel format with formulas intact.

RESPONSE:

See the workpapers for these calculations provided on the attached CD.

The $161 million savings calculated for KU represents the difference in the Kentucky jurisdictional revenue requirement for all years depicted on the worksheet tabs entitled "Summary" for two files entitled "Revenue Requirement for KU-As Filed-No Retired" and "Revenue Requirement for KU-As Filed GCOC-STD During Const.-No Retired."

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The $225 million savings calculated for LG&E represents the difference in the Kentucky jurisdictional revenue requirement for all years depicted on the worksheet tabs entitled "Summary" for two files entitled "Revenue Requirement for LG&E-As Filed-No Retired" and "Revenue Requirement for LG&E -As Filed GCOC-STD Dur Const.-No Retired."

The calculations are also depicted in the data tables for the two graphs depicted in the two files entitled "Chart .16% STD During Construction - KU" and "Chart .16% STD During Construction - LG&E."

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13. Refer to the Direct Testimony of Lane Kollen page 5 lines 7 through 11. Provide the calculation of the referenced $75 million and $97 million in savings for KU and LG&E customers, respectively. Provide all data, assumptions and calculations in Excel format with formulas intact.

RESPONSE:

See the workpapers for these calculations provided on the attached CD.

The $75 million savings calculated for KU represents the difference in the Kentucky jurisdictional revenue requirement for 2016 depicted on the worksheet tabs entitled "Summary" for two files entitled "Revenue Requirement for KU-As Filed GCOC-STD During Const.-No Retired" and "Revenue Requirement for KU-Securitized COC-STD During Const.-No Retired."

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The $97 million savings calculated for LG&E represents the difference in the Kentucky jurisdictional revenue requirement for 2016 depicted on the worksheet tabs entitled "Summary" for two files entitled "Revenue Requirement for LG&E -As Filed GCOC-STD Dur Const.-No Retired" and "Revenue Requirement for LG&E –Securitized COC-STD Dur Const.-No Retired."

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14. Refer to the Direct Testimony of Lane Kollen page 5 lines 16 through 23. Provide all prior Commission decisions that includes "the allocation of all new tax-exempt pollution control debt" to environmental projects.

RESPONSE:

Mr. Kollen is proposing a refinement of the existing methodology to more directly tie the actual debt issued to finance the new environmental projects to the costs recovered through the ECR. The Commission has refined its methodology on several occasions to achieve this objective. Mr. Kollen is aware of the Commission's Order in Case No. 93-465 wherein the Commission used the 5.85% interest rate from a new tax-exempt pollution control debt issue as the rate of return for all costs pursuant to the 1994 Plan.

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15. Refer to the Direct Testimony of Lane Kollen page 8 lines 1 through 4. Provide all supporting documentation that would indicate that "the proposed regulations may never be adopted."

RESPONSE:

Mr. Kollen's understanding is that a proposed regulation is not final and binding until such time as it becomes final. According to the EPA's website, a proposed regulation is one that is currently under development. At this stage, the proposed regulation could later become final as proposed, become final as modified, or withdrawn altogether.

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16. Refer to the Direct Testimony of Lane Kollen pages 11 and 12. Provide all data, assumptions and calculations in Excel format with formulas intact that support the two graphs.

RESPONSE:

See the workpapers for these calculations and graphs provided on the attached CD. See also the response to 1-12.

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17. Refer to the Direct Testimony of Lane Kollen page 12 lines 6 through 8. Provide a listing of all states that have authorized the use of securitization to finance the costs of assets that the utility currently owns and operates (excluding storm reconstruction assets).

RESPONSE:

Mr. Kollen is aware that Wisconsin and West Virginia have authorized the use of securitization financing for this purpose. Please refer to the presentation by Saber Partners at the NARUC Winter 2006 meeting attached and provided in electronic format on attached CD.

SABER PARTNERS, LLC
ADVISORS & INVESTORS

Utility Securitization: A Brief History

With New Uses to Lower Ratepayer Costs

Joseph S. Fichera, CEO
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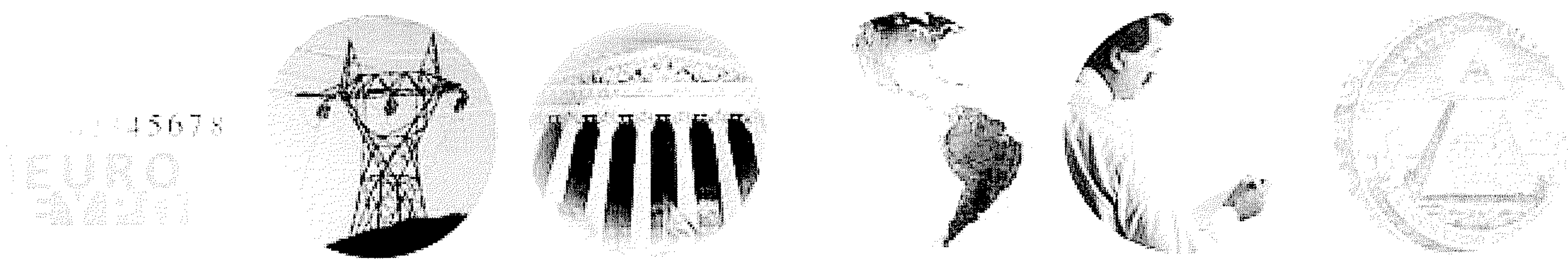
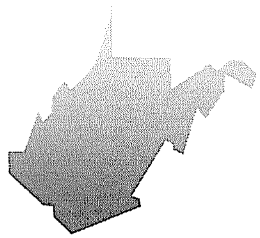
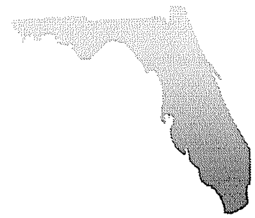


Saber Financial Advisor Securitization Assignments

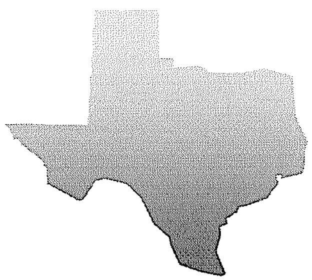
Wisconsin



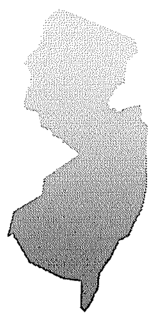
West Virginia



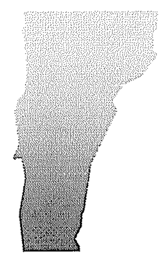
Florida



Texas



New Jersey



Vermont

Why does Securitization matter?

- **Public interest solution to slowing the rise in energy rates**
  - Benefits consumers and utilities
- **Mitigates long-term rate impact of investment decisions and government mandated costs**
  - Least cost alternative in global capital markets.
- **Creates economic value in capital markets from Commission's powerful regulatory authority**

Different Names; Same Technology

Also known as....

- Rate Reduction Bonds
- Stranded Cost Bonds
- Utility Fee Bonds
- Energy Recovery Bonds
- Environmental Trust Bonds
- Storm Recovery Bonds

What is Securitization?

It is not...

- ***Not*** **a bond by the Utility**
  - Non-recourse to utility, its shareholders and creditors, completely independent corporate bond
- ***Not*** **a Municipal Bond**
  - Not a charge against the state's taxing or budget authority
- ***Not*** **an Asset Backed Security**
  - No pool of receivables, financial assets or other complexities

What is Securitization?

It is:

- Direct borrowing on rate base – "ratepayer-backed" bond
- Guaranteed by State's regulatory authority over rates – an R.O. (regulatory obligation) not G.O. (general obligation)
- AAA rated, top quality
- Lowest cost way to raise investment funds in debt capital markets today

What Makes a Successful Securitization

- **Specific state statutory authorization (Generally) which includes a "State Pledge" of non-impairment (Always)**
- **Irrevocable financing order which includes an automatic adjustment mechanism (true-up/true-down)**
- **Active Commission oversight of, and involvement in, financing process**

Debt Structure

- **Issued by a special purpose entity, owned by utility and responsible to the Commission – "bankruptcy remote"**

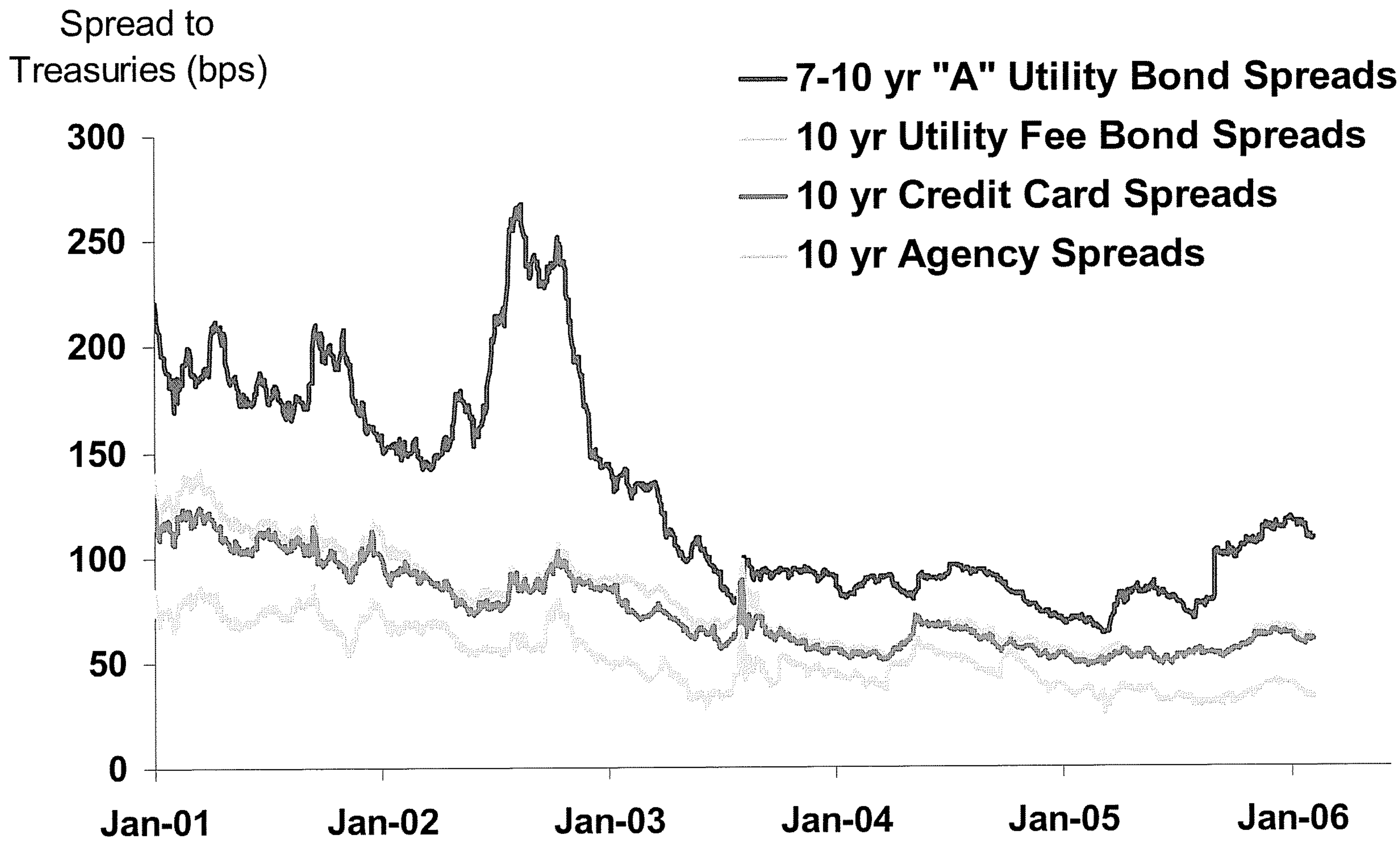
- **Secured by and payable from a dedicated component of the retail rate**
  - Broadly based
  - Non-bypassable
  - Not more than 20% of the total bundled rate

Any Credit Risk Effectively Eliminated

"The broad-based nature of the true-up mechanism and the State Pledge will serve to effectively eliminate for all practical purposes and circumstances any credit risk associated with the Bonds."

Source: SEC Prospectus: TXU Electric Delivery

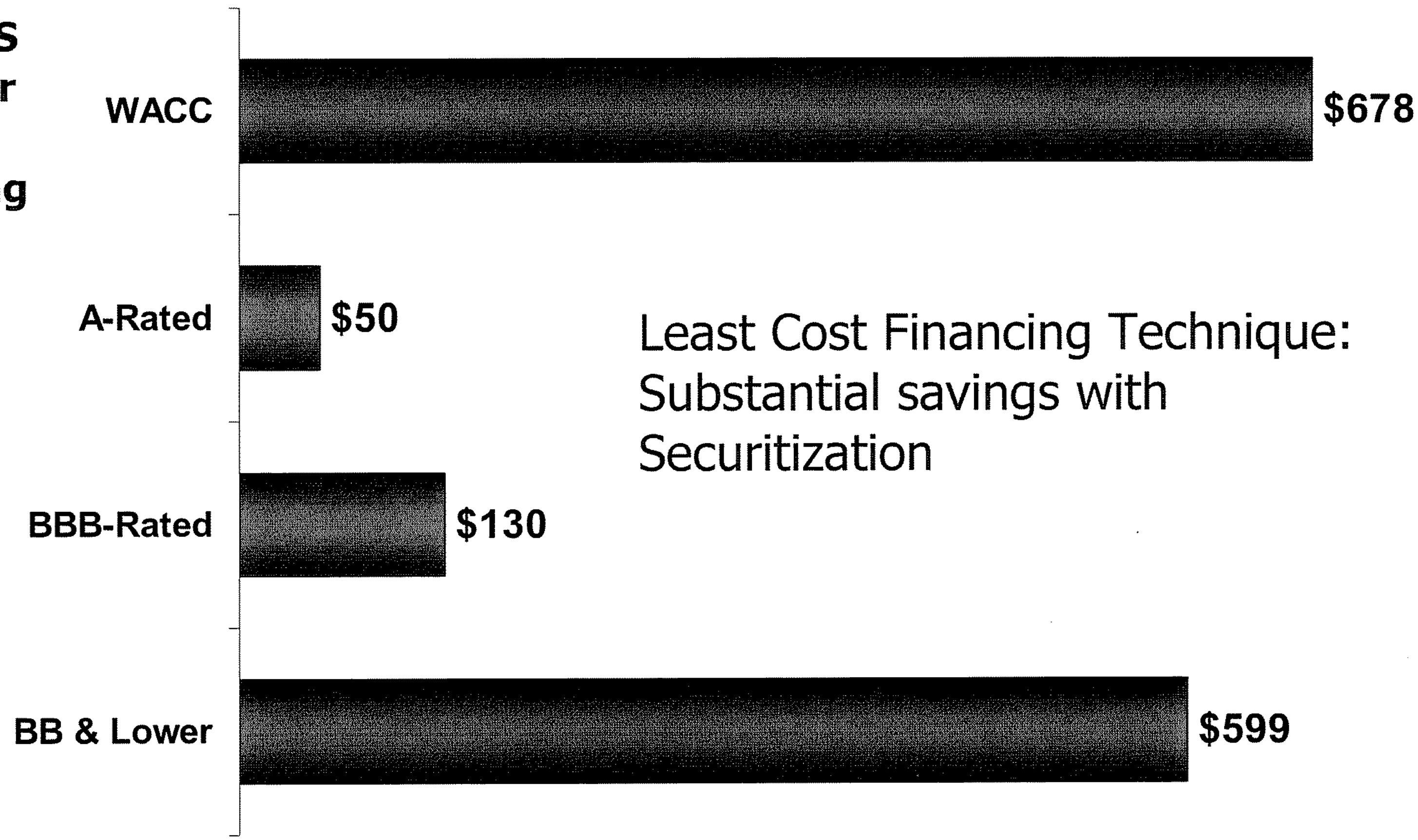
Lower/Less Volatile Rates than Utility bonds



Source: Citigroup

With Large Benefits to Ratepayers: e.g., $1 billion 10-Year Average Life Financing

SAVINGS vs. Other Utility Financing Options



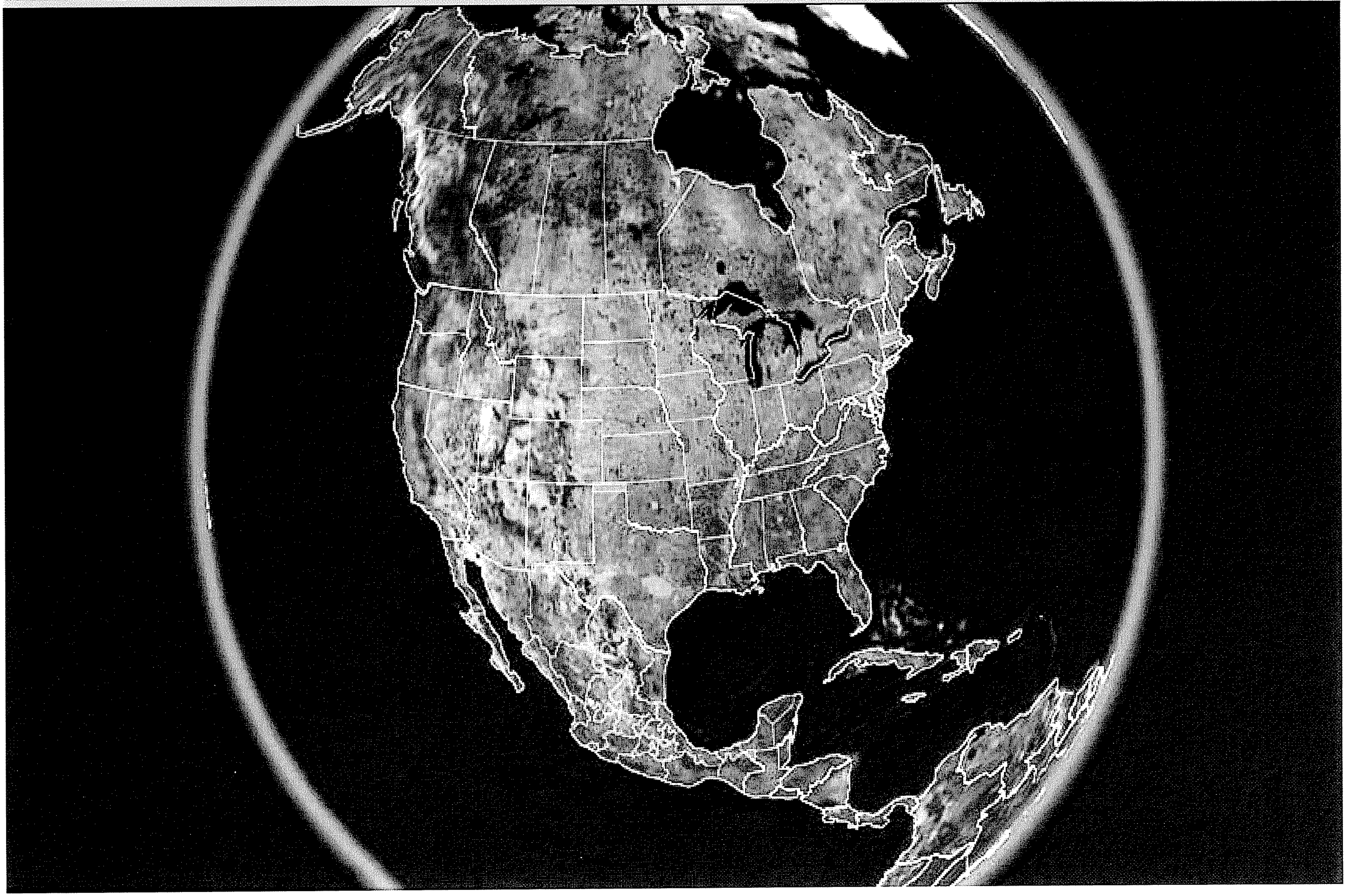
Total Nominal Savings from Securitization, $ millions

Least Cost Financing Technique: Substantial savings with Securitization

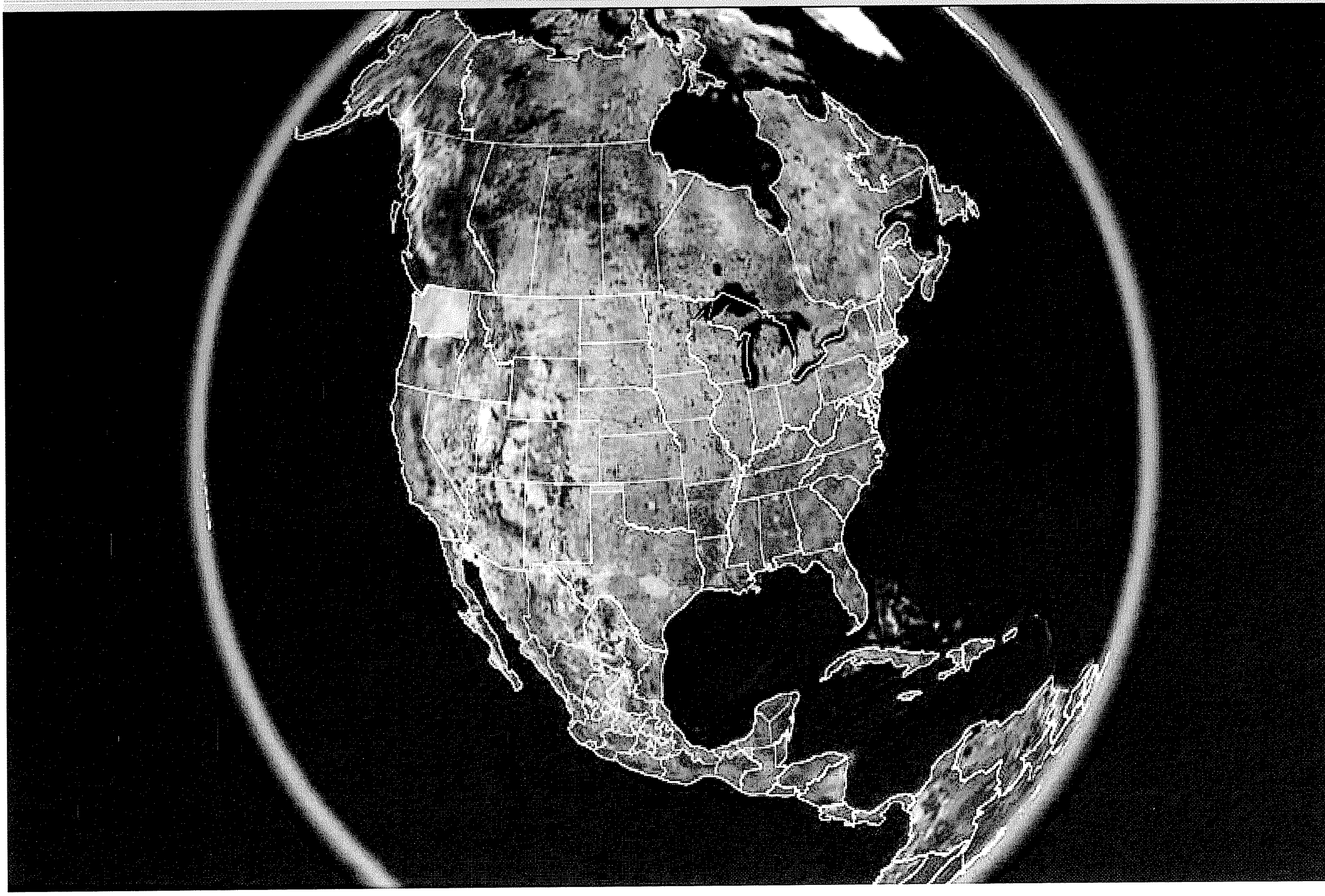
Based on Citigroup utility bonds spreads versus securitization spread 2001-2006

Differing uses in States…expanding over time

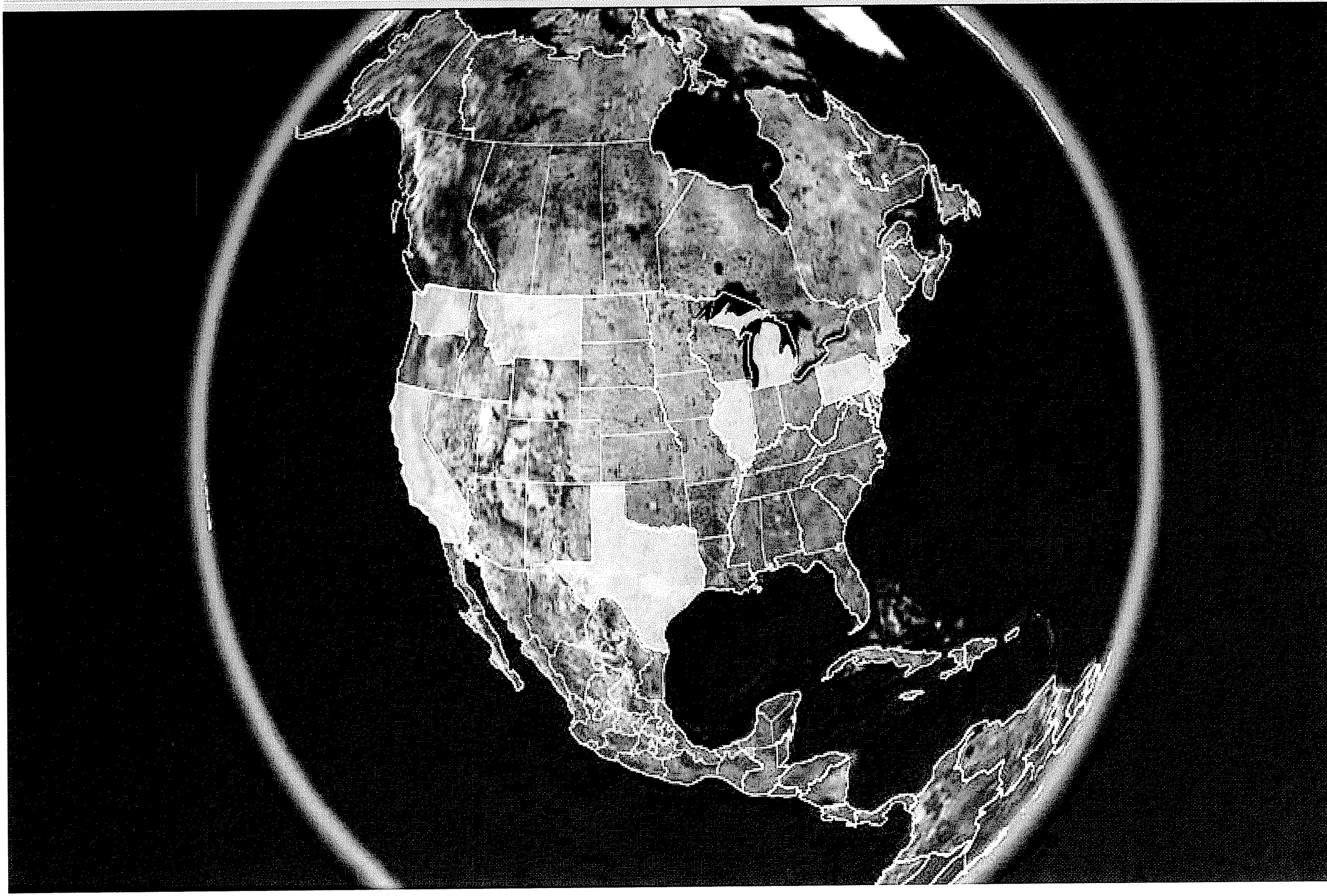
Expanding Use of Securitization



Expanding Use of Securitization

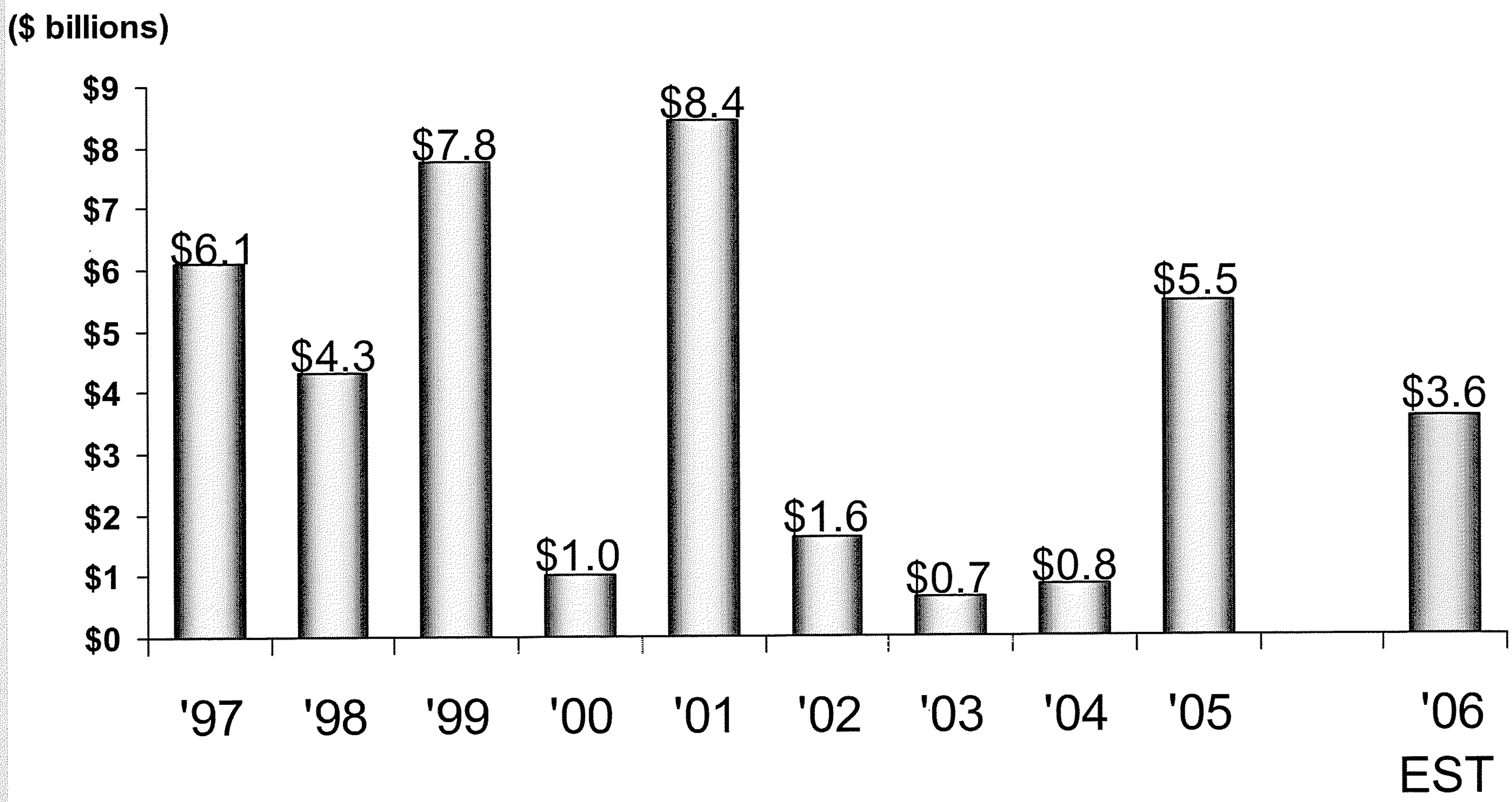


Expanding Use of Securitization



Expanding Use of Securitization

$33.5 Billion Issued; $3.6 billion Expected '06



Sources: Bloomberg, Transition Bond prospectuses, and other SEC filings.

1994 - 1997

- **Introduced by Puget Power**
  - Demand side management
- **Followed by several issuances from California**
  - Finance 10% rate reduction facilitating deregulation
  - Consumer groups oppose

Date	Issue	State	Size ($mm)	Purpose
Jun-95	Puget Power, Series 1995-1	Washington	202.3	Demand Side Management
1997	Puget Power, Series 1997	Washington	35.2	Demand Side Management
Nov-97	PG&E, Ser. 1997-1	California	2,901.0	Rate Reduction
Dec-97	SCE, Ser. 1997-1	California	2,463.0	Rate Reduction
Dec-97	SDG&E, Ser. 1997-1	California	658.0	Rate Reduction
		Total	$ 6,259.5	

Source: SEC Documents, Fitch.

1998 - 2000

- **Financing method quickly embraced for stranded costs by utilities**
- **Securitization becomes synonymous with deregulation and stranded costs**

Date	Issue	State	Size ($mm)	Purpose
Dec-98	Montana Power	Montana	62.7	Stranded Costs
Dec-98	ComEd, Ser. 1998	Illinois	3,400.0	Stranded Costs
Dec-98	Illinois Power, Ser. 1998-1	Illinois	864.0	Stranded Costs
Mar-99	PECO, Ser. 1999-A	Pennsylvania	4,000.0	Stranded Costs
Apr-99	Sierra Pacific	California	24.0	Stranded Costs
Jul-99	Boston Edison	Massachusetts	725.0	Stranded Costs
Jul-99	PP&L, Ser. 1999-1	Pennsylvania	2,420.0	Stranded Costs
Nov-99	West Penn Power, Ser. 1999-A	Pennsylvania	600.0	Stranded Costs
Apr-00	PECO, Ser. 2000-A	Pennsylvania	1,000.0	Stranded Costs
		Total	$ 13,095.7	

Source: SEC Documents.

2001

- **Energy Crisis/Enron – PG&E goes bankrupt – Securitization bonds perform without a hitch... no downgrade or even watchlist**

- **Texas issues securitization order but requires active and involved oversight of financing process to "ensure lowest cost of funds"**

Date	Issue	State	Size ($mm)	Purpose
Jan-01	PSE&G, Ser. 2001-1	New Jersey	2,525.0	Stranded Costs
Feb-01	PECO, Ser. 2001-A	Pennsylvania	805.5	Stranded Costs
Mar-01	Detroit Edison, Ser. 2001-1	Michigan	1,750.0	Stranded Costs
Mar-01	CL&P, Ser. 2001-1	Connecticut	1,438.4	Stranded Costs
Apr-01	PSNH, Ser. 2001-1	New Hampshire	525.0	Stranded Costs
May-01	WMECO, Ser. 2001-1	Massachusetts	155.0	Stranded Costs
Oct-01	CenterPoint Energy, Ser. 2001-1	Texas	748.9	Stranded Costs
Oct-01	Consumers Funding, Ser. 2001-1	Michigan	468.6	Stranded Costs
		Total	$ 8,416.3	

Source: SEC Documents.

2002 - 2003

- **Vermont passes cost mitigation statute for power purchase buy-downs**
- **PG&E bankruptcy settlement - consumer groups now PROPOSE $3 billion securitization to refinance new regulatory asset carried at WACC**

Date	Issue	State	Size ($mm)	Purpose
Jan-02	PSNH, Ser. 2002-1	New Hampshire	50.0	Stranded Costs
Jan-02	CPL, Ser. 2002-1	Texas	797.3	Stranded Costs
Jun-02	JCP&L 2002-1	New Jersey	320.0	Stranded Costs
Dec-02	Atlantic City Electric 2002-1	New Jersey	440.0	Stranded Costs
Aug-03	Oncor Electric 2003-1	Texas	500.0	Stranded Costs
Dec-03	Atlantic City Electric 2003-1	New Jersey	152.0	Stranded Costs
		Total	$ 2,259.3	

Source: SEC Documents.

2004 - 2005

- **Financing method expands to uses other than "stranded" investments/costs**
- **New Jersey issues securitization for deferred balances**

Date	Issue	State	Size ($mm)	Purpose
May-04	Oncor/TXU Electric 2004-1	Texas	789.8	Stranded Costs
Jul-04	Rockland Electric	New Jersey	46.3	Deferred Balances
Feb-05	Pacific Gas and Electric	California	1,887.9	Refinance Regulatory Asset
Feb-05	Mass. Special Purpose RRB Trust	Massachusetts	674.5	PPC Contract Buydown
Sep-05	Public Service Electric & Gas	New Jersey	102.7	Deferred Balances
Sep-05	West Penn Power, Ser. 2005-A	Pennsylvania	115.0	Stranded Costs
Nov-05	Pacific Gas and Electric	California	844.5	Refinance Regulatory Asset
Dec-05	CenterPoint Energy	Texas	1,851.0	Stranded Costs
		Total	$10,675.7	
		Total All Deals	$36,342.5	

Source: SEC Documents.

2006 Estimate

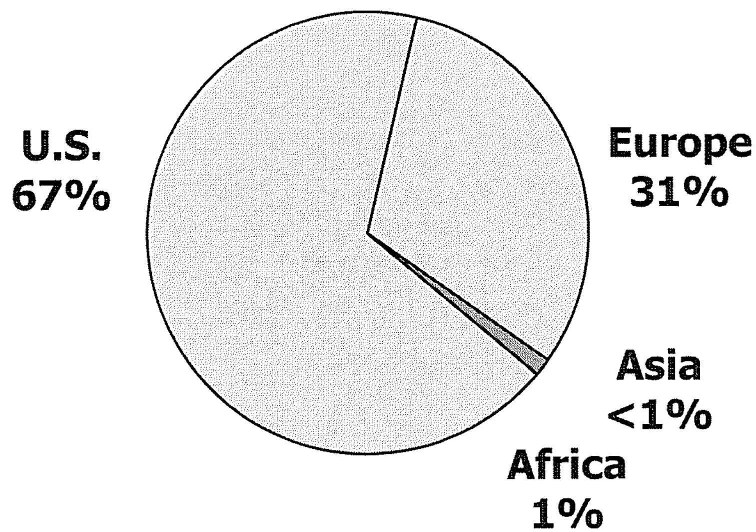
- **Wisconsin and West Virginia apply method to environmental facilities**
- **Florida to use technology for storm recovery financing/reserves**
- **Idaho legislature authorizes securitization for any utility purpose up to 40% of balance sheet**

Date	Issue	State	Size ($mm)	Purpose
Pending	Wisconsin Electric Power	Wisconsin	450.0	Enviromental Control
Pending	Allegheny Power	West Virginia	381.0	Enviromental Control
Pending	JCP&L	New Jersey	300.0	Deferred Balances
Pending	AEP	Texas	1,300.0	Stranded Costs
Pending	Florida Power & Light	Florida	1,050.0	Storm Recovery
Pending	Gulf Power	Florida	150.0	Storm Recovery
		Total	$ 3,631.0	

Source: SEC Documents, Proposal Requests.

Bonds begin to Attract International Investors

In December 2005:
Texas Transition Bonds - 33% sold internationally...



TX: $1.85 Billion CNP
Series A

TTB's
Texas Transition Bonds

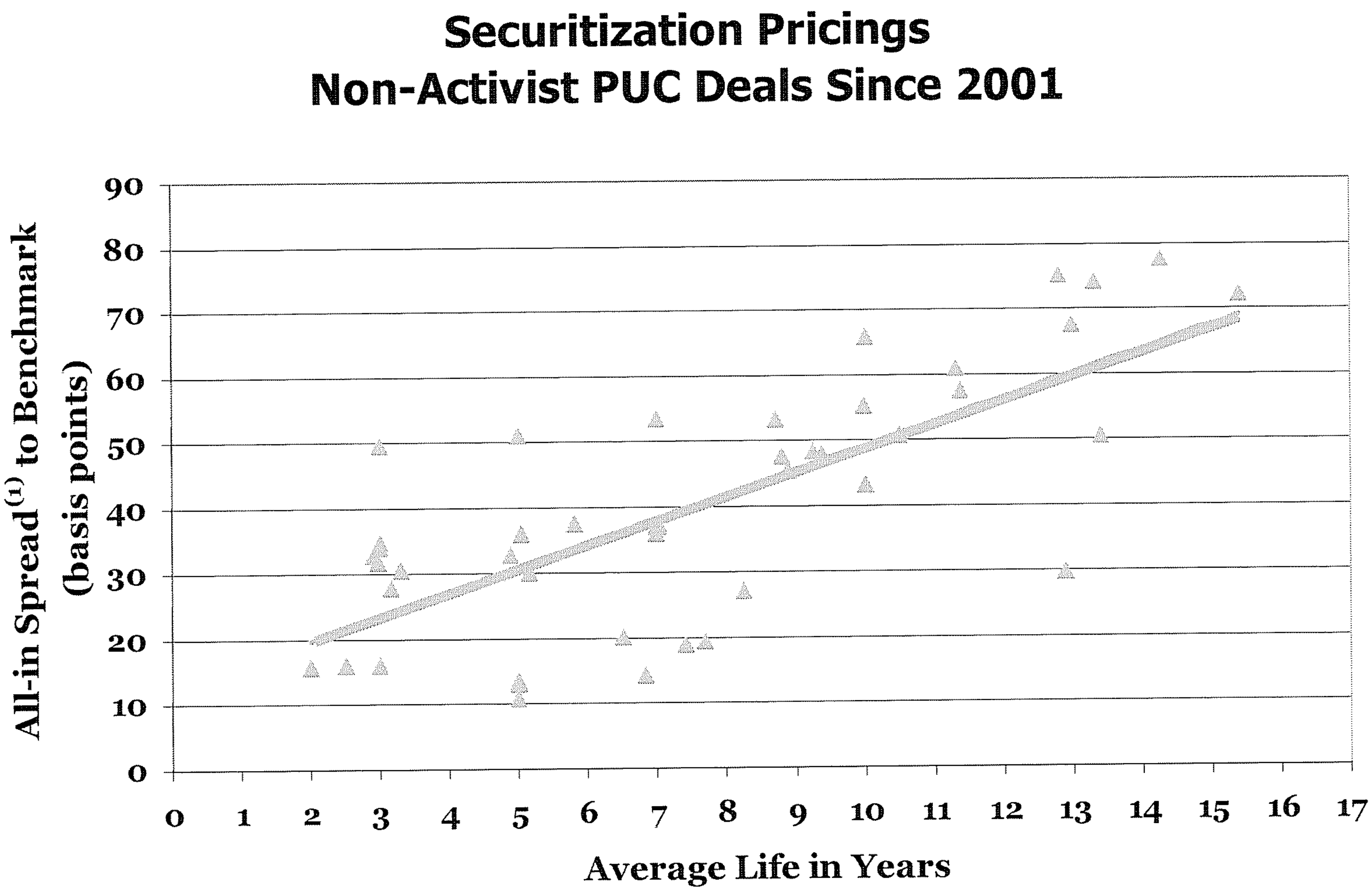
But Ratepayer Savings are not Automatic

- Irrevocable Order? No post-financing review or adjustments
  - Closer consideration of prudency, eligibility for securitization
- Up-front transaction costs, interest rate: every dollar a ratepayer dollar
  - More involved Commission and Staff and cooperation with utility throughout financing process
- High Transaction Costs?
  - Commission with state-wide, ratepayer perspective and leverage
  - Programmatic, state-wide approach keeps costs low versus application by application

But Ratepayer Savings are not Automatic

- **Lowest Possible Bond Rate, Fees and Other Costs?**
  - Wall Street always looking for a bargain - doesn't want to pay full value if it can
  - Requires cooperation between Commission and Utility. Activist Commission/Staff/Utility with Wall Street in all negotiations with financial service providers, counsel, investors and others
  - Active vs. Passive makes substantial difference in ratepayer costs

Difference Active PUC Makes in Pricing



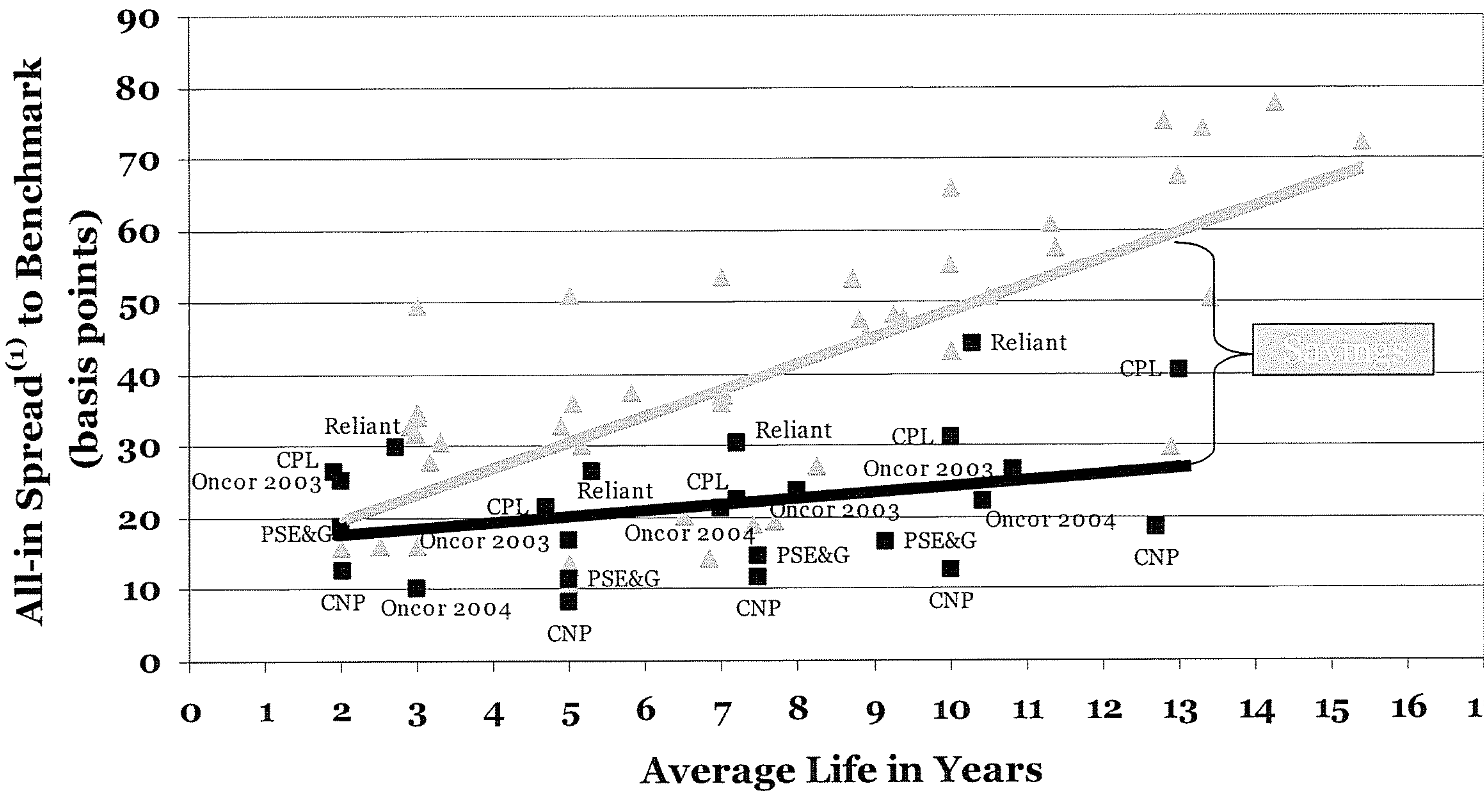
Source: SEC Prospectus, Bloomberg. (1) All-in spread includes credit spread, underwriting and structuring fees, if any.

Difference Active PUC Makes in Pricing

Passive

Activist PUC with FA

Ratepayer Savings from Pricing
Activist PUC Deals vs. All Others Since 2001



opprietary

Source: SEC Prospectus, Bloomberg. (1) All-in spread includes credit spread, underwriting and structuring fees, if any.

Going Forward:
Policy Questions/Steps for a "New" Financial Tool

- Step One:
  Where can securitization be used? (utility infrastructure, government mandated costs) Commissions can be pro-active.

- Step Two:
  How can the transaction costs be minimized? Programmatic approaches, closer cooperation between Commission and utility.

- Step Three:
  How can the benefits to ratepayers be maximized and extended? Achieve <u>lowest</u> financing costs and potential positive balance sheet effect resulting in lower WACC for the utility

SABER PARTNERS, LLC
ADVISORS & INVESTORS

Utility Securitization: A Brief History

With New Uses to Lower Ratepayer Costs

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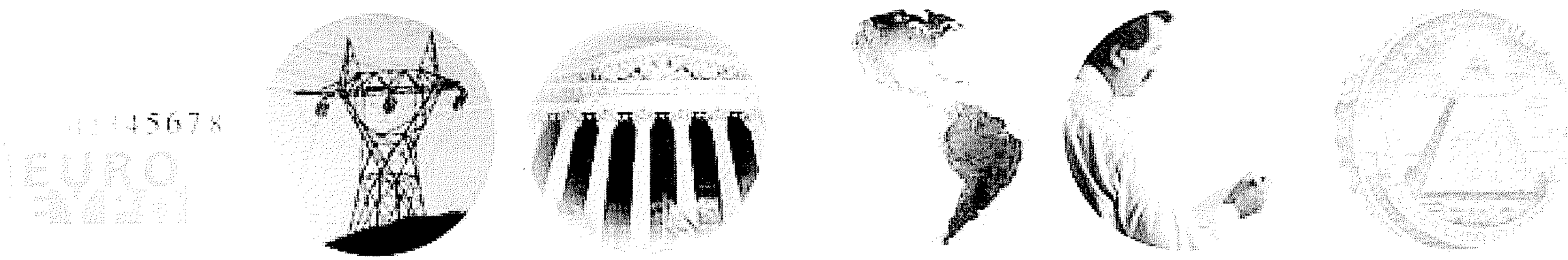

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	**CASE NO. 2011-00161**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	**CASE NO. 2011-00162**

RESPONSE OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
TO KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY'S
DATA REQUESTS

18. Please state specifically the support for Mr. Kollen's statement at lines 5-6 at page 20 of this testimony, "Short-term debt is used to finance the projects during construction, and generally is not used to finance the plant in service amounts …."

RESPONSE:

This statement is based on Mr. Kollen's experience in multiple ratemaking proceedings, including claims made by utilities, such as Atmos Energy Corp., and precedent by various state commissions, including the Public Utilities Commission of Ohio, which generally does not include short term debt in the capital structure for the rate of return applied to rate base excluding CWIP.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	**CASE NO. 2011-00161**

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APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	**CASE NO. 2011-00162**

RESPONSE OF KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. TO KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY'S DATA REQUESTS

19. Please provide all documents in Mr. Kollen's possession which refer or relate to Florida Public Service Commission Rule 25-14.004

RESPONSE:

Please refer to the FPSC Rule 25-14.004, which was quoted in its entirety in Mr. Kollen's Direct Testimony at 25-26. In addition, please refer to copies of MFR schedules filed by Florida Power & Light Company in a recent rate proceeding that address the requirements of this FPSC Rule and the FPSC Order in a recent TECO rate proceeding, in which the Commission applied this rule despite TECO's arguments against it. Copies of the relevant pages of these documents are attached and included in electronic format on the attached CD.

PARENT(S) DEBT INFORMATION

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY
AND SUBSIDIARIES
DOCKET NO.: 080677-EI

EXPLANATION: Provide information required in order to adjust income tax expenses by reason of interest expense of parent(s) that may be invested in the equity of the utility in question. If a projected test period is used, provide on both a projected and historical basis.

Type of Data Shown:
____ Proj. Subsequent Yr Ended 12/31/11
____ Prior Year Ended __/__/__
_X_ Historical Test Year Ended 12/31/08
Witness: Kim Ousdahl

Line No.	(1)	(2) Amount	(3) Percent of Capital	(4) Cost Rate	(5) Weighted Cost
1.	Long Term Debt	$	%	%	%
2.	Short Term Debt				
3.	Preferred Stock				
4.	Common Equity				
5.	Deferred Income Tax				
6.	Investment Tax Credits				
7.	Other (specify)				
8.	Total	$	100.00%		%

9. Weighted cost of parent debt x 38.575% (or applicable consolidated tax rate) x equity of subsidiary = ______ %

10. **NOTE: For Historic Test Year Ended 12/31/08, please refer to MFR C-24 Historic contained in the 2010 Test Year MFR Schedules.**

Supporting Schedules:

Recap Schedules:

PARENT(S) DEBT INFORMATION

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO. 080677-EI

EXPLANATION: Provide information required in order to adjust income tax expenses by reason of interest expense of parent(s) that may be invested in the equity of the utility in question. If a projected test period is used, provide on both a projected and historical basis.

Type of Data Shown:
_X_ Proj. Subsequent Yr Ended 12/31/11
___ Prior Year Ended __/__/__
___ Historical Test Year Ended __/__/__
Witness: Kim Ousdahl

Line No.	(1)	(2) Amount	(3) Percent of Capital	(4) Cost Rate	(5) Weighted Cost
1.	NOTE: FPL GROUP, INC., THE PARENT OF FLORIDA POWER & LIGHT COMPANY, IS PROJECTED TO HAVE NO OUTSTANDING DEBT DURING 2011				
2.	Long Term Debt	$	%	%	%
3.	Short Term Debt				
4.	Preferred Stock				
5.	Common Equity				
6.	Deferred Income Tax				
7.	Investment Tax Credits				
8.	Other (specify)				
9.	Total	$	100.00%		%

10. Weighted cost of parent debt x 38.575% (or applicable consolidated tax rate) x equity of subsidiary = _____%

Supporting Schedules:

Recap Schedules:

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Tampa Electric Company.	DOCKET NO. 080317-EI ORDER NO. PSC-09-0283-FOF-EI ISSUED: April 30, 2009

The following Commissioners participated in the disposition of this matter:

MATTHEW M. CARTER II, Chairman
LISA POLAK EDGAR
KATRINA J. McMURRIAN
NANCY ARGENZIANO
NATHAN A. SKOP

APPEARANCES:

LEE L. WILLIS, JAMES D. BEASLEY, KENNETH R. HART, and J. JEFFRY WAHLEN, ESQUIRES, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302
On behalf of Tampa Electric Company (TECO)

PATTY CHRISTENSEN, ESQUIRE, Office of Public Counsel, c/o The Florida Legislature, 111 W. Madison Street, Room 812, Tallahassee Florida 32399-1400
On behalf of the Office of Public Counsel (OPC)

CECILIA BRADLEY, ESQUIRE, Office of the Attorney General, The Capitol, PL-01, Tallahassee, Florida 32399-1050
On behalf of the Citizens of Florida (OAG)

MICHAEL B. TWOMEY, ESQUIRE, P.O. Box 5256, Tallahassee, Florida 32314-5256
On behalf of AARP

JON MOYLE, JR. and VICKI GORDON KAUFMAN, ESQUIRES, Keefe Anchors Gordon & Moyle, P.A., 118 North Gadsden Street, Tallahassee, Florida 32312 and JOHN W. MCWHIRTER, JR., ESQUIRE, P.O. Box 3350, Tampa, Florida 33601-3350
On behalf of the Florida Industrial Power Users Group (FIPUG)

ROBERT SCHEFFEL WRIGHT and JOHN T. LAVIA, III, ESQUIRES, Young van Assenderp, P.A., 225 South Adams Street, Suite 200, Tallahassee, Florida 32301
On behalf of the Florida Retail Federation (FRF)

Depreciation Expense

Based on our previous adjustments under Projected Level of Plant in Service, Annualization of Five Simple Cycle Combustion Turbine Units, and Annualization of Rail Facilities, the projected 2009 Depreciation and Amortization Expense of $194,608,000 shall be reduced by $7,579,485, to an adjusted amount of $187,028,515. (See Schedule 3)

Taxes Other Than Income Taxes

We find that TECO has properly forecasted Taxes Other Than Income Taxes and no adjustment is warranted.

Parent Debt Adjustment

Rule 25-14.004, F.A.C., states that "the income tax expense of a regulated company shall be adjusted to reflect the income tax expense of the parent debt that may be invested in the equity of the subsidiary where a parent-subsidiary relationship exists and the parties to the relationship join in the filing of a consolidated income tax return." Further, Rule 25-14.004(3), F.A.C., states that "it shall be a rebuttable presumption that a parent's investment in any subsidiary or in its own operations shall be considered to have been made in the same ratios as exist in the parent's overall capital structure." Rule 25-14.004(4), F.A.C., provides that:

> The adjustment shall be made by multiplying the debt ratio of the parent by the debt cost of the parent. This product shall be multiplied by the statutory tax rate applicable to the consolidated entity. This result shall be multiplied by the equity dollars of the subsidiary, excluding its retained earnings. The resulting dollar amount shall be used to adjust the income tax expense of the utility.

In MFR Schedule C-24, TECO provided some of the information required to calculate the parent debt adjustment, but did not include an adjustment to income tax expense to reflect the parent debt in the calculation of its requested revenue requirement. In Interrogatory No. 11, the Company was asked to provide the financial information necessary to make a parent debt adjustment in accordance with Rule 25-14.004, F.A.C. The Company provided the following information:

Debt Ratio of the parent	19.01%
Debt Cost Rate of the parent	6.90%
Consolidated Statutory Tax Rate	38.575%
Subsidiary Equity	$1,901,759,000

In its response, the Company also provided an alternative set of data, which it labeled "Company Position," as follows:

Debt Ratio of the parent	0.00%
Debt Cost Rate of the parent	6.90%
Consolidated Statutory Tax Rate	38.575%
Subsidiary Equity	$0 - $72,957,000

TECO reiterated its objection to application of the parent debt adjustment in this case, as expressed in the testimony of TECO witness Gillette.

In direct testimony, witness Gillette stated that TECO Energy, the parent company of TECO, has $404 million of long term debt on its books. Witness Gillette also stated that there were circumstances where the Company could rebut the presumption in Rule 25-14.004(3), F.A.C., that a parent debt adjustment is appropriate. According to witness Gillette, "TECO Energy did not raise debt to invest in Tampa Electric, nor did it invest the proceeds of the debt it did raise as equity in Tampa Electric." Witness Gillette stated that the debt was related to TECO Energy's investment in TPS, a former subsidiary which is no longer in existence.

Witness Gillette provided the following expanded rationale for not applying the parent debt adjustment:

> 1) as stated above, the debt that exists at the parent was raised for TECO Energy's merchant power plant investments at TPS and was not used to invest in Tampa Electric, 2) imputing parent debt would result in an inappropriate imputed capital structure given how TECO Energy raises capital on behalf of its regulated and unregulated companies, 3) imputing debt for the cumulative equity infused to Tampa Electric over time ignores that the vast majority of the equity that exists at Tampa Electric was invested by TECO Energy in Tampa Electric during times when either no parent debt existed or at a time when parent debt was actually being repaid, and 4) TECO Energy's internal subsidiary 100 percent net income dividend policy results in an overstatement of the paid in capital equity amounts that have required the investment of parent capital as used in the parent company debt rule calculation.

Witness Gillette stated that at the time of the Company's last rate case, TECO Energy had approximately $100,000,000 of debt related to its Employee Stock Option Trust, and that this debt was not imputed to TECO in the rate case. We have reviewed Order No. PSC-93-0165-FOF-EI, and note that there is no discussion of the applicability of the parent debt adjustment in the order.[30]

Witness Gillette stated that between 1998 and 2003, TECO Energy raised approximately $3.4 billion dollars of external capital, including approximately $2.1 billion in debt. He asserted that the bulk of this capital was invested in TPS and other unregulated subsidiaries. He also

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[30] See Order No. PSC-93-0165-FOF-EI, issued February 2, 1993, in Docket No. 920324-EI, In re: Application for a rate increase by Tampa Electric Company.

stated that TECO Energy has not raised debt outside this time frame and has, in fact, paid the balance down to its present level.

In addition to his argument that the parent debt adjustment is inappropriate because none of the debt proceeds were invested in TECO, witness Gillette also stated that the $1,901,759,000 of projected subsidiary equity is overstated because TECO Energy's policy requires subsidiaries to pay dividends equal to all of their net income to the parent. Most of these dividends are paid out to TECO Energy shareholders, and some are reinvested in the subsidiaries. He expressed the opinion that the accounting treatment of these transactions results in amounts that should properly be classified as retained earnings of TECO, but are instead classified as paid in capital on the financial statements. Rule 25-4.004(4), F.A.C., states that the subsidiary equity used in calculating the parent debt adjustment does not include retained earnings. Witness Gillette maintained that the appropriate subsidiary equity to be used in a parent debt calculation in this case would be approximately $72 million, rather than the approximately $1.9 billion reflected in the financial statements.

In its post-hearing brief, OPC disagreed with TECO's rationale for not applying the parent debt adjustment. OPC noted that the assets of TPS are no longer on the consolidated books of TECO Energy, and that the remaining debt must be repaid from corporate funds of TECO Energy, which could include funds generated by TECO. OPC noted that TECO Energy receives the tax benefit of the interest paid on the debt, but cannot specifically link the tax benefit to a subsidiary which no longer exists. In its statement of position, OPC stated that a parent debt adjustment should be made in the amount of $8,140,774. OPC does not explain how this amount was calculated.

We concur with OPC that the Company has not effectively rebutted the presumption that the parent debt adjustment should be applied in this case. In his testimony, witness Gillette admitted that "tracing funds is a complicated and difficult exercise." In ruling that a parent debt adjustment was required in a case involving Indiantown Company, Inc., we stated:

> Based on our analysis, the rule requires that a parent debt adjustment be made in this proceeding. Further, the rule does not allow for specific identification of debt from the parent to the subsidiary utility. Since the utility is included in the consolidated income tax returns of the parent, we believe that it would be very difficult to prove specific identification to only the utility. Rule 25-14.004(3), Florida Administrative Code, states that it shall be a rebuttable presumption that a parent's investment in any subsidiary or in its own operations shall be considered to have been made in the same ratios as exist in the parent's overall capital structure.[31]

Rule 25-14.004, F.A.C., is based on the premise that debt at the parent level supports a portion of the parent's equity investment in the utility. Since the interest expense on such debt is

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[31] See Order No. PSC-00-2054-PAA-WS, issued October 27, 2000, in Docket No. 990939-WS, In re: Application for rate increase in Martin County by Indiantown Company, Inc.

deductible by the parent for income tax purposes, the income tax expense of the regulated subsidiary is reduced by the tax effect. Furthermore, the Company has not demonstrated that the interest on the debt on its books can be attributed to any source other than the general funds of the parent.

With respect to the subsidiary equity amount to be used in the calculation of the parent debt adjustment, we find that it is appropriate to use the full amount of paid in capital reflected on the books and records of the Company. Witness Gillette criticized what he characterizes as a change in classification of retained earnings to paid in capital resulting from TECO Energy's dividend policy. However, he does not contend that the current books and records are not presented in accordance with generally accepted accounting principles (GAAP). In a case involving United Telephone of Florida (UTI), we required the use of UTI's current capital structure in the computation of a parent debt adjustment, stating:

> However, we must determine the capital structure to be used for that adjustment. United, although opposed to the parent debt adjustment, proposed that if such an adjustment was to be made it should utilize the parent's 1983 capital structure which preceded the significant increase in debt at the parent level to finance the acquisition and expansion of US Sprint. OPC contends that the Commission should not apply the parent company debt adjustment proposed by United based on UTI's debt level in 1984, because such a procedure would implicitly assume that it is possible to trace dollars. However, if the Commission chooses a procedure to trace funds, then a double leverage capital adjustment utilizing UTI's 1983 consolidated capital structure and cost rates to determine UTF's cost of common equity should be used.
>
> We believe that the current UTI capital structure should be used for determining the parent debt adjustment. It would not be appropriate to use UTF's 1983 capital structure for ratemaking purposes in 1993; similarly, it would make no sense to use UTI's 1983 capital structure for making a parent debt adjustment for ratemaking purposes in 1993. Additionally, we will not use the double leverage adjustment suggested by OPC. The double leverage formula inherently traces funds to their capital source, but we consider funds to be fungible. Also, we believe that a double leverage adjustment for UTF may result in an ROE that understates the Company's required return on capital. Accordingly, we shall apply the parent debt adjustment as set forth in Rule 25-14.004.[32]

Accordingly, the parent debt adjustment shall be applied in this case, and the elements of the computation shall be based on the projected test year capital structures of TECO Energy and TECO. Our calculation of the system income tax expense reduction is as follows:

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[32] See Order No. PSC-92-0708-FOF-TL, issued July 24, 1992, in Docket No. 910980-TL, In re: Application for a rate increase by United Telephone Company of Florida.

Debt Ratio of parent		.1901	
Debt Cost Rate of parent	X	.069	
	=	.0131169	
Consolidated Tax Rate	X	.38575	
	=	.005059844	
Subsidiary Equity	X	$1,901,759	(in 000s)
Parent Debt Adjustment	=	$9,623	(in 000s)

In MFR Schedule C-4, p. 5, TECO calculated a jurisdictional separation factor for income taxes of 1.003612. Applying this factor to the adjustment calculated above results in a jurisdictional adjustment of $9,657,000 (9,623,000 x 1.003612).

In conclusion, the Company has not effectively rebutted the presumption that a parent debt adjustment should be applied pursuant to Rule 25-14.004, F.A.C. The appropriate subsidiary equity amount to be used in the calculation is the projected test year equity of $1,901,759,000. Accordingly, the appropriate jurisdictional adjustment is a reduction of income tax expense in the amount of $9,657,000.

Income Tax Expense

Based on our adjustments, the requested total income tax expense of $48,492,000 (current, deferred, and ITC) shall be increased by $6,004,887 resulting in an adjusted total of $54,496,887 for the 2009 projected test year. (See Schedule 3)

Amount Requested	$48,492,000
Commission Adjustments:	
Issue 76 – Parent Debt	(9,657,000)
Effect of Other Adjustments	14,677,178
Interest Synchronization	984,709
Total Adjustments	6,004,887
Adjusted Amount	$54,496,887

Projected Net Operating Income

Based on our adjustments, the appropriate net operating income for the 2009 projected test year is $215,013,533. (See Schedule 3)

REVENUE REQUIREMENTS

Net Operating Income Multiplier

In calculating the net operating income (NOI) multiplier, the only component at issue is the bad debt rate. In its calculation, TECO used its 2009 projected bad debt rate of .349 percent,

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	**CASE NO. 2011-00161**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	**CASE NO. 2011-00162**

RESPONSE OF KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. TO KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY'S DATA REQUESTS

20. Please provide a complete copy of Mr. Kollen's testimony in March 2002 and July 2009 before the Florida Public Service Commission involving Florida Power and Light Company.

RESPONSE:

A copy of the public version of each testimony is attached and provided in electronic format on the attached CD.

Public Disclosure Version

BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION

IN RE:

PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY) DOCKET NO. 080677-EI

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

JULY 2009

BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION

IN RE:

PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	))	DOCKET NO. 080677-EI

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BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION

IN RE:

PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY)	DOCKET NO. 080677-EI

DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

<u>**Qualifications**</u>

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree, both from the University of Toledo. I also earned a Master of Arts degree from Luther Rice University. I am a Certified

Public Accountant, with a practice license; and a Certified Management Accountant.

I have been an active participant in the utility industry for more than thirty years, both as a consultant and as an employee. Since 1986, I have been a consultant with Kennedy and Associates, providing services to consumers of utility services and state and local government agencies in the areas of utility planning, ratemaking, accounting, taxes, financial reporting, financing and management decision-making. From 1983 to 1986, I was a consultant with Energy Management Associates, providing services to investor and consumer owned utility companies in the areas of planning, financial reporting, financing, ratemaking and management decision-making. From 1976 to 1983, I was employed by The Toledo Edison Company in a series of positions providing services in the areas of planning, accounting, financial and statistical reporting and taxes.

I have appeared as an expert witness on utility planning, ratemaking, accounting, reporting, financing, and tax issues before state and federal regulatory commissions and courts on nearly two hundred occasions. In many of those proceedings, I have represented state and local ratemaking agencies or their Staffs, including the Louisiana Public Service Commission, Georgia Public Service Commission and various groups of Cities with original rate jurisdiction in Texas. I also have appeared before the Florida Public Service Commission

("Commission") in numerous proceedings, including the two most recent Florida Power & Light Company ("FPL" or "Company") base rate proceedings in Docket Nos. 050045-EI (2005) and 001148-EI (2002). I have developed and presented papers at various industry conferences on ratemaking, accounting, and tax issues. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Summary

Q. On whose behalf are you testifying?

A. I am offering testimony on behalf of the South Florida Hospital and Healthcare Association ("SFHHA") and individual healthcare institutions (collectively, the "Hospitals") taking electric service on the FPL system.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the Company's proposed series of base rate and recovery clause increases and to make recommendations on the appropriate rate increase amounts.

Q. Please summarize your testimony.

A. The Company has requested an unprecedented series of rate increases in this proceeding of more than $1,550 million, the magnitude of which may not be immediately evident, and which would represent a radical change in the Commission's ratemaking process. These increases consist of a base rate increase of $1,044 million on January 1, 2010, another series of increases on January 1, 2010 summing to $77 million through various recovery clauses due to transfers in the recovery of such costs between base rates and the clauses, another base rate increase of $247 million on January 1, 2011, an estimated initial base rate increase of $182 million through a Generation Base Rate Adjustment ("GBRA") mechanism for West County Energy Center Unit 3 ("WCEC 3") on June 1, 2011 and another series of unknown future base rate increases through the GBRA for future generation costs.

I recommend that the Commission reject the Company's proposals in this proceeding for all base rate increases after January 1, 2010. Instead, the Company should file for future base rate increases closer to the effective dates of such increases using then current costs and assumptions. The Commission realistically cannot determine at this time the reasonable level of revenues and costs that should be recovered through base rates some three or more years into the future, particularly given the present economic uncertainty. Further, the Commission should not adopt a GBRA that provides the Company an almost unfettered ability to automatically impose base rate increases to recover selective increases in certain costs without consideration of increases in revenues and reductions in all other costs.

In addition, I recommend that the Commission reduce the Company's base rates by at least $336.338 million (net of transfers of costs between base rates and various recovery clauses) on January 1, 2010 compared to the Company's requested increase of $1,044 million. My recommendation reflects the SFHHA adjustments to remove the excessive and inappropriate costs that affect the rate base, operating income and rate of return that are included in the Company's request. I have summarized the effects of the SFHHA recommendations on the following table.

FLORIDA POWER AND LIGHT BASE RATE INCREASE
SUMMARY OF SFHHA RECOMMENDATIONS
TEST YEAR ENDING DECEMBER 31, 2010
($ MILLIONS)

	Amount
FPL Requested Base Rate Increase	$ 1,043.535
Operating Income Adjustments:	
Reduce O&M Expenses - Other (Maintain Status Quo)	(169.256)
Reduce O&M Expenses - DOE Settlement Refunds	(9.030)
Reduce O&M Expenses - AMI Deployment Savings	(5.885)
Reduce O&M Expenses - Development of New CIS	(7.274)
Remove Annual Storm Damage Expense Accrual	(149.162)
Reduce O&M Labor, Payroll Taxes, and Fringe Benefits - Productivity Improvements	(36.641)
Reduce O&M Labor, Payroll Taxes, and Fringe Benefits - Nuclear Staffing	(21.925)
Remove Depreciation Expense - Development of New CIS	(0.506)
Reduce Depreciation Expense - Capital Cost Reductions	(26.719)
Reduce Depreciation Expense - Five Year Amortization of Depreciation Reserve Surplus	(247.566)
Reduce Depreciation Expense - No Acceleration of Capital Recovery Costs	(63.605)
Reduce Depreciation Expense - Forty Year Service Life for Combined Cycle Gas Units	(123.730)
Reduce Depreciation Expense - Economic Stimulus Grants for AMI Deployment	(1.584)
Rate Base Adjustments:	
Reflect Capitalization/Deferral of CIS O&M Expenses	0.428
Reduce Plant for Capital Expenditure Reductions	(92.520)
Restate Accum Depr to Reflect Capital Expenditure Reductions	3.668
Restate Accum Depr to Reflect Five Year Amortization of Depreciation Reserve Surplus	14.569
Restate Accum Depr to Adjust Amortization Periods for Capital Recovery Costs	3.741
Restate Accum Depr to Reflect Forty Year Service Lives for Combined Cycle Gas Units	7.276
Restate Gross Plant and Accum Depr to Reflect Economic Stimulus for AMI Deployment	(2.267)
Capital Structure and Rate of Return Adjustments:	
Rebalance Common Equity and Debt in Capital Structure	(121.424)
Rebalance Long and Short Term Debt in Capital Structure	(11.018)
Eliminate FIN 48 Adjustment to Accumulated Deferred Income Tax	(17.643)
Reallocate Pro Rata Adjustments to Exclude Cust Deposits, ADIT, ITC	(48.695)
Increase ADIT for Depreciation Changes	(8.909)
Restate ROE at 10.4%	(232.610)
Restate Short Term Debt Interest Rate	(11.785)
Total SFHHA Adjustments	**($1,379.873)**
SFHHA Recommendation for Base Rate Change on January 1, 2010	**($336.338)**

The remainder of my testimony is structured to follow the sequence of my summary. In the next section, I address the Company's proposed base rate increases effective on January 1, 2011 and beyond and why the Commission should reject those increases in this proceeding. In the subsequent sections, I focus on the Company's proposed base rate increase effective on January 1, 2010 and the appropriate adjustments to that proposed increase by major ratemaking component (operating income, rate base, and capitalization and rate of return) and by issue affecting each of those major ratemaking components.

<u>**Economic Uncertainty and Requested Base Increase on January 1, 2011 and GBRA Increase on June 1, 2011**</u>

Q. Should the Commission approve a second base rate increase to be effective on January 1, 2011 based on a "subsequent" test year of 2011?

A. No. First, the Commission cannot determine at this time what the reasonable revenues and costs will be in 2011 given the present economic uncertainty. It will be difficult enough to determine the reasonable level of revenues and costs for the 2010 test year, which itself is two years removed from actual experience and is based on a budgeting process covering 2009 and 2010, but which began in mid-2008 prior to the meltdown in the financial markets and the recession. Since 2008, the Company has engaged in extensive cost reductions compared to its 2009 budget, thus rendering the 2009 budget unreliable as the basis for the 2010 test year forecast, and even more so for the 2011 subsequent test year forecast. I subsequently describe the Company's cost reductions in both capital expenditures and operating expenses compared to 2008 actual amounts and compared to the Company's 2009 budget.

Second, there is no evidence that there will be actual savings to ratepayers resulting from the avoidance of a separate proceeding sometime in 2010 for rates that will be effective in 2011. Company witness Ms. Kim Ousdahl asserts that the Commission should determine the 2011 rate increase in this proceeding to "avoid the cost and distraction for all parties of back-to-back rate proceedings." [Ousdahl Direct at 12]. However, if the Company's 2011 test year costs are reduced as the result of the Company's cost cutting efforts compared to the projections in the Company's 2011 subsequent year forecasts in this proceeding, then the cost of a separate proceeding in 2010 or in some future year is likely to pale against the effect of such savings in a subsequent proceeding. It would be far better to incur the cost of another rate proceeding in 2010 or later and to endure the alleged "distraction" of such a proceeding in order to avoid an excessive increase for 2011 that is not merited and that cannot be reasonably determined at this time. The reasonable levels of revenues and costs in 2011 are not known and measurable today.

Third, the Company is not harmed if the Commission rejects the proposed 2011 subsequent year increase because it can file another case in 2010 using more current assumptions and data. Company witness Ms. Ousdahl recognizes that the

Commission may reject the Company's request for the January 1, 2011 base rate increase and concludes that this may result in another rate filing. [Ousdahl Direct at 4]. That may be and the Commission can consider such a request after it is filed, if one is filed. Regardless, Ms. Ousdahl does not claim that the Company will harmed if it must make a subsequent filing, nor could it reasonably make such a claim.

Fourth, it may very well be that the Company will not file another case in 2010 if it continues to reduce its costs through additional reductions in capital expenditures and operating expenses as it addresses the lack of growth in sales and revenues due to the economic recession. In any event, it is premature both for the Commission and the Company to make a determination at this time as to the Company's revenue requirement in 2011 given the present uncertainty.

Q. Should the Commission approve the Company's proposed GBRA?

A. No. The Company's proposed GBRA mechanism represents a radical departure from the traditional ratemaking process and should be rejected for several reasons. First, the Company's proposed GBRA will be a permanent mechanism that will operate to automatically implement significant future base rate increases as the Company adds new generation. The Company effectively will self-implement those base rate increases without the normal regulatory scrutiny and resulting cost-control discipline that accompanies the filing, review and adjudication of a comprehensive base rate case. The proposed GBRA will not be limited only to the West County Energy Center Unit 3 revenue requirement, but also will include all future generation and related transmission costs.

Second, the circumstances and nature of the proposed GBRA differ from those of the expiring GBRA. The expiring GBRA was implemented in conjunction with a settlement in Docket Nos. 050045-EI and 050188-EI, which provided for no base rate increases for the next four years except for costs recovered through various adjustment mechanisms, including the GBRA and various clauses, unless the Company's earnings fell below a threshold level. In addition, the GBRA mechanism was temporary and will expire at the end of this year unless it is re-established in this proceeding.

Third, the proposed GBRA mechanism constitutes a single issue and one-way base rate increase mechanism that fails to consider cost reductions that the Company may achieve in other areas. For example, the proposed mechanism will not reflect cost reductions due to the continued depreciation on or retirement of existing production plant investment as acknowledged by the Company in response to SFHHA Interrogatory 112. The proposed GBRA mechanism allows the Company to retain the savings resulting from ongoing recoveries of existing plant investment through depreciation from ratepayers, the cost free capital resulting from ongoing accelerated tax depreciation, increases in revenues due to customer and usage growth and capital expenditure and expense cost reductions. This fundamental flaw will be accentuated the longer the period between comprehensive base rate proceedings. I have attached a copy of the Company's response to SFHHA Interrogatory 112 as my Exhibit___(LK-2)

Third, the GBRA recovery will be based on the Company's first year estimate of the revenue requirement of the new generation and related transmission when that revenue requirement is at its peak level. Once the Company self-implements a base rate increase when a new project enters commercial operation, that rate increase will be permanent and remain at the level when implemented, at least until the next comprehensive base rate proceeding. Once the increase is implemented, base revenues will not be revised downward as the underlying rate base amount declines due to increases in accumulated depreciation or as the related cost of capital declines due to increases in cost-free accumulated deferred income taxes and apparently never is trued-up to actual. This approach allows the Company to increase base rates when the revenue requirement is at the maximum level and then to retain any savings due to the declining rate base or actual expenses that are less than initially projected until the next comprehensive base rate proceeding. This approach also will allow the Company to avoid or at least defer a voluntary comprehensive review of its base rates absent growth in its other base rate costs that exceeds such savings.

Fourth, the GBRA mechanism is not even a proposed tariff even though it is self-implementing. There is no proposed tariff to review. There is not even a detailed description of the mechanism and the revenue requirement computations in the testimony of any FPL witness. Company witness Ms. Ousdahl simply refers to the existing GBRA in her testimony. However, the description of the existing GBRA mechanism in paragraph 17 of the settlement agreement in Docket Nos. 050045-EI and 050188-EI and approved by the Commission in Order No. PSC-05-0902-S-EI is not sufficiently detailed for a permanent self-implementing base rate increase mechanism. I have attached a copy of the settlement agreement in that proceeding as my Exhibit___(LK-3) for ease of reference.

Fifth, based on the Company's computation of the proposed West County Energy Center 3 revenue requirement, there are serious computational problems in the Company's proposed GBRA, all of which serve to improperly increase the Company's revenue requirement.

Q. Please describe the computational problems with the Company's proposed GBRA.

A. There are numerous problems that are evident from a review of the Company's separate computation of the WCEC 3 revenue requirement for the first year of its operation that the Company provided in this proceeding. The Commission should not allow the use (or misuse) of a GBRA to provide the Company with excessive revenues. First, the proposed rate of return is overstated due to an excessive common equity ratio of 55.80%. A reasonable capital structure consists of 50.0% common equity and 50.0% debt for rating agency reporting purposes and 53.46%

common equity and 46.54% debt for ratemaking purposes, according to SFHHA witness Mr. Richard Baudino's testimony in this proceeding.

Second, the proposed rate of return is overstated due to the Company's use of the so-called "incremental" cost of debt rather than the weighted average cost of debt outstanding. For example, the Company's computations reflect a 6.43% cost of debt on Schedule D-1a for the WCEC 3 revenue requirement compared to the 5.81% weighted average cost of debt on Schedule D-1a for the 2011 subsequent test year revenue requirement.

Third, the proposed rate of return is overstated due to the failure to include low-cost short term debt in the capital structure. If the WCEC 3 rate base investment was included in the rate base for the base revenue requirement, then the return applied to the rate base investment would include short-term debt.

Fourth, the rate of return is overstated because it does not include any cost-free ADIT in the capital structure. The Company should not be allowed to retain this benefit by computationally assuming that it does not exist.

Fifth, the depreciation expense is overstated because it is based on a 25 year life for the WCEC 3 facility. Such a facility has a reasonable service life of 40 years and depreciation expense should be based on the reasonable service life, not an accelerated life established only to accelerate and increase near-term ratemaking recovery. I address the appropriate service lives for depreciation expense in the Operating Income section of my testimony.

Q. How should the Company recover its costs associated with the West County Energy Center Unit 3 and future generation facilities?

A. If the Company believes that it has or will have a revenue deficiency for 2011, then it should file a request to increase its base rates some time in 2010. Similarly, if the Company believes that it has or will have a revenue deficiency in years after 2011, then it should file requests to increase its base rates in those years.

II. OPERATING INCOME ISSUES

Operation and Maintenance Expense – Summary

Q. How does the Company's proposed O&M expense compare to the Company's most recent actual O&M expense?

A. The Company proposes an incredible increase in O&M expense for the test year compared to the actual O&M expense for the most recent three historical years as summarized on its MFR Schedules C-1 and C-36. In contrast to its actual success in controlling expenses in 2008 and prior years, the Company projects an increase in non-fuel O&M expense recovered through base rates of $387.414 million, from $1,306.953 million in 2008 to $1,694.367 million in the 2010 test year, as shown on MFR Schedule C-1. However, this increase masks the full magnitude of the proposed increase because the Company proposes that $20.880 million of the projected 2010 expense be transferred to clause recovery. Thus, the actual proposed increase is $408.294 million, which is an increase of more than 31% compared the Company's actual 2008 O&M expense.

This requested growth is excessive when compared to the Company's actual experience in recent years. The Company's MFR Schedule C-36 compares the O&M expense in the years 2007 through the 2010 test year (although MFR Schedule C-36 includes only the "Commission" proforma adjustments and does not include the "Company" proforma adjustments), the annual percentage increase in the O&M expense, and the annual percentage increase in the CPI. The results show that the Company effectively managed its total non-fuel O&M expense each year to levels less than the actual CPI growth and even reduced its actual non-fuel O&M expense in 2008 by an absolute $26.842 million, or 2.0%, compared to the actual O&M expense in 2007. In other words, the Company achieved significant productivity gains in its O&M expenses over the last several years, offsetting and even surpassing the growth in these expenses caused by inflation.

This requested growth also is excessive when compared to the Company's actual O&M expenses for the first quarter this year compared to the same quarter last year. The Company has further reduced its O&M expense in 2009 compared to 2008 and compared to its 2009 budget. The Company's SEC 10-Q for the 1st Quarter 2009 indicates that it has reduced its actual O&M expense in the first quarter by $38 million compared to 2008, of which $9 million was due to the DOE settlement that I subsequently discuss. In its press release announcing first quarter earnings, FPL Group cited the Company's reduction in O&M expense as the driver of the Company's increased earnings in the first quarter 2009 compared to the first quarter 2008. [redacted] I have attached a copy of the relevant pages from the Company's 10-Q as my Exhibit___(LK-4), a copy of the FPL Group press release as my

Exhibit___(LK-5), and a copy of the [redacted] as my Exhibit___(LK-6) (confidential).

Q. Are expense increases of this magnitude justified?

A. No. This level of increase is wildly excessive and cannot reasonably be justified given the present economic circumstances, particularly in South Florida, the Company's proven ability to implement cost reductions, including the effects of productivity improvements through capital investment and continued efficiency improvements through the adoption of best practices, and given the Company's actual cost reductions compared to 2008 and compared to its budget that it already has implemented to-date in 2009.

The Company's test year O&M expenses should be no more than the actual 2008 expenses, a "status quo" basis, except for limited known and measurable changes. Only certain of the increases in expenses are known and measurable at this time, and thus potentially justified, such as the expenses due to the commercial operation of new generation, specifically the West County Energy Center Units 1 and 2 in 2009. However, the increases in other expenses are not known and measurable, but rather represent significant and largely unjustified expansions of programs, proposed increases in staffing levels, and other general increases resulting from inflation and other forecasting assumptions that tend to increase expenses when used to support a proposed rate increase.

Q. How do you propose the Commission proceed on the Company's requested level of O&M expense increases?

A. I recommend a significant reduction in the Company's proposed non-fuel O&M expense, which I address through both a "top-down" approach and a "bottom-up" approach. Under the top-down approach, I recommend that the Commission limit the test year O&M expenses to the actual 2008 O&M expenses, adjusted only for appropriate known and measurable changes, such as transfers between base rates and clause recoveries and increases to incorporate the WCEC 1 and 2 expenses. Under the bottom-up approach, I recommend that the Commission reduce the Company's proposed test year O&M expense to reflect specific adjustments to the Company's requested amount. Given the Company's reductions in O&M expenses in the first quarter of this year to levels below 2008, the Commission may wish to consider these reductions on an annualized basis as a further reduction in the test year O&M expense under either a top-down or bottom-up approach.

Q. Please describe the top-down approach to determine the reasonable level of test year O&M expense.

A. The top-down approach reflects the "status quo" and relies on the use of the historic test year as the best evidence of the Company's expenses, but with adjustments for known and measurable changes to those expenses that the Company likely will incur in the projected test year. The Commission should reject the concept that the Company's projected O&M expenses are known and measurable in the abstract based on its budget and forecasting process and that the Company cannot or will not manage its expenses in its self-interest.

The top-down status quo approach assumes that there should be and will be no general increase in non-fuel O&M expense increase in the 2010 test year compared to the 2008 actual expense. The top-down approach assumes that the 2008 level of expense not only was adequate in that year but will remain adequate in the future absent known and measurable changes and that increases in expenses due to inflation, if any, in 2009 and 2010, will be at least offset by reductions in expenses due to productivity improvements and other cost-reductions. The top-down approach is consistent with the manner in which the Company actually manages its O&M expense and the Company's reductions in non-fuel O&M expenses for the first quarter this year compared to the same quarter last year.

In addition, the top-down approach recognizes that there are and should be savings in O&M expense resulting from the costs of new "long-term infrastructure investments" to "better manage work, assets, people, and finances" [Barrett at 27] that are included in rate base. The rate base investments have the effect of "reducing costs while enhancing many aspects of service to customers." [Barrett at 27]. The Commission should ensure that ratepayers actually get the benefit of the expense reductions due to the investments made to achieve those reductions.

Finally, the top-down approach recognizes that utilities manage their O&M expenses in response to the timing and level of ratemaking recoveries. The Company aggressively manages its O&M expense when it cannot contemporaneously recover increases and is able to retain the earnings benefits from its actions. However, if the Company is provided excessive recoveries based on inflated forecasts, such recoveries will allow the Company to increase its expenses without consequence and override the normal self-interest in cost-control. [redacted] I have attached these [redacted] as my Exhibit___(LK-7 (confidential) and Exhibit___(8) (confidential) [redacted], respectively.

In conjunction with the top-down approach, the Commission should adjust the "status quo" O&M expense for known and measurable adjustments to: 1) subtract expenses that no longer will be incurred or no longer recovered through base rates, such as those transferred to various clauses for recovery, and 2) add specific and unavoidable cost increases, such as the increases in non-fuel O&M expense associated with WCEC 1 and 2.

Q. **Please describe the bottom-up approach to determine the reasonable level of test year O&M expense.**

A. I recommend that the Commission also review the specifics of the Company's projected 2010 test year expense through a bottom-up approach to determine if the requested amounts are reasonable. Amounts that are not reasonable should be specifically disallowed. In this manner, the Commission can determine the overall reasonable level of O&M expense through the top-down approach, but confirm and refine the result of the top-down approach by starting with the Company's request and reducing it for unreasonable expenses through the bottom-up approach.

Q. What is your recommendation on the test year O&M expense?

A. I recommend that the Commission reduce the Company's test year O&M expense by $397.648 million. This reduces the Company's requested test year O&M expense from the $1,694.367 million requested to the $1,306.953 million actual 2008 adjusted downward on a net basis to $1,296.719 million for the following known and measurable changes: 1) the reduction in O&M expense due to the transfer of certain expenses to various clauses for recovery ($20.880 million), 2) the increase in O&M expense for WCEC 1 and 2 ($18.918 million), and 3) the reduction due to the DOE refunds that I subsequently discuss ($9.000 million), and 4) the increase due to all other Company adjustments reflected on MFR Schedule C-2, except for the storm damage expense ($0.728 million).

I obtained the Company's proposed known and measurable changes from the Company adjustments shown on MFR Schedule C-2. I obtained the O&M expense amount for WCEC 1 and 2 from the Company's response to SFHHA

Interrogatory 119. I attached a copy of this response as my Exhibit___(LK-9). I discuss and provide the source of the DOE refund amount in a subsequent section of my testimony.

Although I recommend this net reduction in O&M expense based on the top-down approach, I also have disaggregated the net reduction into various specific adjustments and disallowances that are based on the bottom-up approach. I have characterized the difference between the net reduction based on the top-down approach and the sum of the specific adjustments based on the bottom-up approach as an "other" adjustment on the table in the Summary section of my testimony.

Q. Please describe your bottom-up review of the Company's proposed test year O&M expense.

A. First, I reviewed the forecast assumptions reflected in the Company's projected 2010 O&M expense to identify assumption-driven reasons for the proposed increase in O&M expenses. Second, I reviewed the Company's O&M expense benchmark analysis summarized on MFR Schedule C-41 to identify specific functional areas where the Company proposed growth in test year expenses above and beyond the levels indicated by the benchmark computations. Third, I compared the Company's O&M expense in the test year to 2008 actual levels to identify specific functional areas where the Company proposed excessive growth in O&M expenses. Finally, I reviewed the Company's responses to the SFHHA discovery as well as the responses to other parties' discovery to identify inappropriate and excessive expenses. I subsequently address each of the bottom-up specific adjustments that I recommend and reflect the amount of each adjustment on the table in the Summary section of my testimony.

<u>**Operation and Maintenance Expense – Productivity Savings**</u>

Q. **Did the Company include an explicit assumption regarding productivity improvements and the resulting expense reductions given the Company's history of controlling the growth in payroll costs below the rate of inflation?**

A. No. The Company reflected significant increases in payroll costs, including inflation and merit increases and staffing increases, but did not explicitly reflect an offset against these proposed expense increases for productivity improvements.

Q. **Is the Company's failure to explicitly take into account productivity improvements in its O&M expense consistent with its historic experience?**

A. No. In recent years and as I previously described, the Company has successfully managed its O&M expenses so that annual increases are less than the rate of inflation.

Q. **What is the source of the Company's productivity improvements?**

A. The Company achieves such productivity improvements through capital investment in assets that reduce maintenance requirements and allow fewer employees to do more in less time as well as the adoption of best practices in managing processes. Company witness J. A. Stall described how the Company's nuclear production business unit achieves such efficiencies. Mr. Stall states that: "we continuously pursue standardization of programs and procedures and share best practices among our nuclear fleet, improving safety, efficiencies, and reducing costs." [Stall Direct at 15]. Mr. Stall also described the Turkey Point Excellence project, stating: "In the "process category, the project focuses on implementing a procedure upgrade program, reducing the corrective action backlog, upgrading training programs, and implementing process improvements consistent with industry best practices. In the "plant improvement" category, the project is focused on reducing on-line and outage maintenance and corrective action backlogs, proactive management of age-related corrosion and coatings related issues, improving operational margin, and implementing a preventative maintenance optimization program." [*Id.*, 22-23]. In addition to the Turkey Point Excellence program, the Company has replaced major equipment components, including steam generators, reactor pressure vessel heads, and a pressurizer at its nuclear units. [*Id.*, 14]. The Company has invested hundreds of millions of dollars in capital expenditures to replace and upgrade other equipment and is now engaged in numerous long-term equipment reliability projects at the nuclear units. [*Id.*, 28].

Q. **Are the Company's historic productivity achievements consistent with the productivity improvements across the national economy?**

A. Yes. The following table summarizes the national non-farm productivity improvements in recent years. The indices were obtained from the U.S. Bureau of Labor Statistics website. I added the column labeled "% Increase" and computed the 5 year simple average, 10 year simple average and the most recent annualized level in the first quarter 2009.

BLS Productivity Statistics

Series Id: PRS85006093
Duration: index, 1992 = 100
Measure: Output Per Hour
Sector: Nonfarm Business

Year	Qtr1	Qtr2	Qtr3	Qtr4	Annual	% Increase
1998	108.356	108.675	109.902	110.476	109.358	
1999	[redacted]					2.9%
2000	113.914	115.938	115.713	116.824	115.687	2.8%
2001	[redacted]					2.5%
2002	122.685	122.88	124.208	124.098	123.468	4.1%
2003	[redacted]					3.7%
2004	130.225	131.73	132.242	132.245	131.614	2.8%
2005	[redacted]					1.7%
2006	134.832	135.642	135.086	134.938	135.123	0.9%
2007	[redacted]					1.4%
2008	139.385	140.98	141.732	141.533	140.897	2.8%
2009	[redacted]					
5 Year Simple Average						1.9%
10 Year Simple Average						2.6%
Most Recent Annualized 1st Qtr						1.9%

Q. **Should the Commission reflect ongoing productivity improvements since 2008 in the test year?**

A. Yes. The Commission should reduce the Company's proposed test year payroll expense to reflect productivity improvements and thus, reductions in payroll and related expenses. In addition to the Company's demonstrated ability to restrain growth in O&M expenses below inflation, the Commission also should consider the Company's capital investment incurred to achieve these savings that is included in rate base. The Company's ratepayers should receive the full benefit of their investment in rate base. If the Commission does not restate the Company's proposed test year O&M expense to reflect these savings, then the Company either will retain the savings or otherwise increase its actual O&M expenses to the levels included in the revenue requirement or some combination of the two.

Q. **Have you quantified the effect of your recommendation?**

A. Yes. The effect is to reduce O&M expense by $36.519 million and the revenue requirement by $36.641 million. I assumed that the Company would achieve productivity gains of 2.0% annually, which will offset the Company's general inflation assumption of 2.0% annually. I based this assumption not only on the Company's most recent experience at more than offsetting inflation increases in 2008, but also on the most recent national historic trends in productivity improvement, which converge on a 2.0% annual improvement as reflected in the preceding table.

The recognition of a 2.0% annual productivity improvements will have the effect of reducing the Company's proposed $765.261 million in payroll expense amount by $30.917 million, or 4.04% reflecting the cumulative and compounded effect of the 2009 and 2010 productivity improvements compared to 2008. I obtained the

O&M expense portion of the Company's projected 2010 payroll expense from the Company's response to SFHHA Interrogatory 297, a copy of which I have attached as my Exhibit___(LK-10).

In addition, there will be reductions of $1.995 million in the related payroll tax expense and $3.607 million in the related fringe benefits expense. To compute these amounts, I applied the same 4.04% cumulative productivity factor to these expense amounts. I obtained the payroll tax expense from the Company's MFR Schedule C-20 and the base recovery portion of the fringe benefits expense from the Company's response to SFHHA Interrogatory 297.

My computations of the reductions in payroll and related expenses are detailed on my Exhibit___(LK-11).

<u>**Operation and Maintenance Expense – Nuclear Staffing**</u>

Q. Does the Company propose an increase in nuclear production O&M expense to reflect staffing increases?

A. Yes. The Company proposes an increase in nuclear staffing of 270 employees, ostensibly to address its employee attrition and training requirements and for its Turkey Point Excellence program. The Company cited employee attrition and training requirements as one reason for the proposed $37.298 million in excess over the benchmark level proposed for nuclear production on its MFR Schedule C-41.

The increase of 270 employees also was cited by Company witness J. A. Stall in his testimony as one of the reasons for the $43.4 million increase in nuclear production O&M expense in the test year compared to 2008 actual expenses. The Company proposes an increase to $424.3 million in the test year from the $380.9 million actually incurred in 2008, according to Exhibit JAS-10 attached to Mr. Stall's Direct Testimony.

The Company also provided a list and brief description of the primary reasons and the amounts related to each of those primary reasons for the proposed increases in nuclear production O&M expense in response to SFHHA Interrogatory 240, a copy of which I have attached as my Exhibit___(LK-12). In this discovery response, the single largest reason identified by the Company was an increase in payroll costs to reflect a significant increase in staffing levels. In that response, the Company quantified the payroll expense effect of adding these employees at $18.5 million for the test year compared to 2008.

Q. How have the Company's actual nuclear staffing levels increased since 2006 and what are the reasons cited by the Company for these increases?

A. The Company previously increased its nuclear staffing levels by 199 positions in 2007 and 2008, or 12%, from 2006 levels, according to the Company's response to SFHHA Interrogatory 291. I have attached a copy of the Company's supplemental response as my Exhibit___(LK-13). The primary reason cited by the Company for the increased nuclear staffing was to "anticipate and ultimately compensate for attrition and retirements."

Q. Is this the same primary reason cited by the Company for the proposed increase of another 270 positions reflected in O&M expense for the test year?

A. Yes. The Company cites the "Apprenticeship Program and operations training pipeline" as the primary reasons for the proposed increases in staffing levels in the test year compared to year end 2008, according to the Company's response to SFHHA Interrogatory 291.

Q. How has the Company's nuclear staffing actually changed since the end of 2008?

A. The Company has been systematically reducing nuclear staffing since September 2008, contrary to the increase in staffing the Company assumed in both its 2009 and 2010 budgets and thus, in the test year O&M expense. In the Company's supplemental response to SFHHA Interrogatory 291, the Company's nuclear staffing peaked in September 2008 and has been steadily declining each month since then.

Q. Should the Commission reflect the additional increases in nuclear production staffing in the test year ostensibly necessary for the Apprenticeship Program and the operations training pipeline?

A. No. The Commission should reject the increase in nuclear production O&M

expense for an additional 270 positions. First, the Company already increased nuclear production staffing by 12% from 2006 to 2008, primarily for this same reason. The Company's proposal will result in a cumulative staffing increase of 23% from 2006 to 2010. Increases of this magnitude for this reason are not reasonable. In effect, the Company claims that it is necessary to increase staffing by 23% over its normal requirements so that it can perpetually train additional personnel to replace employees who will retire or otherwise terminate employment at some future date, but who will not have done so prior to or within the test year. That is not reasonable.

Second, the evidence is that the Company has been steadily reducing nuclear staffing now that the recession has bitten deeper, particularly in the South Florida economy and the Company has been forced to engage in cost reductions compared to its budget.

Third, the Company's proposed increase in staffing levels is inconsistent with the significant capital investments the Company has made and included in rate base to improve the performance and material condition of its nuclear facilities that should reduce staffing levels and O&M expense, not increase it year after year for the same facilities. In addition, the proposed increase in staffing levels is inconsistent with the Company's expense "investments" incurred through such efforts as the Turkey Point Excellence project, reducing maintenance backlogs, reducing attrition rates, and improving employee efficiency consistent with industry best practices. These activities and investments are described extensively by Company witness J. A. Stall in his testimony. At some point, the Company and its ratepayers must reap the expense savings benefit from these large capital and expense investments, the resulting reductions in maintenance activities, and efficiency improvements. Otherwise, there is no justification for the investments or their inclusion in rate base. The point at which ratepayers should reap those benefits is during the test year that serves as the basis for setting the Company's revenue requirement.

Q. What is your recommendation regarding the proposed increase nuclear production staffing expense?

A. I recommend that the Commission reduce the Company's nuclear production O&M expense by $21.852 million to eliminate the Company's request for increased staffing to meet its alleged and seemingly never ending and growing attrition and training requirements. This amount consists of the $18.5 million reduction in O&M payroll expense compared to 2008 levels included in the test ostensibly for this purpose, which was quantified by the Company, plus the related expenses of $1.194 million in payroll taxes and $2.158 million in employee fringe benefits. The computations of the related payroll taxes and employee fringe benefits expenses are detailed on my Exhibit___(LK-14).

<u>Operation and Maintenance Expense – DOE Settlement</u>

Q. Please describe the litigation and settlement between FPL and the U.S. Department of Energy related to the disposal of spent nuclear fuel.

A. FPL and other parties sued the U.S. Department of Energy ("DOE") seeking damages caused by the DOE's failure to dispose of spent fuel from the Company's nuclear generating facilities. FPL described the litigation and the settlement of that litigation in its SEC Form 10-Q for the quarter ending March 31, 2009 as follows:

> **In March 2009, FPL, certain subsidiaries of NextEra Energy Resources and certain nuclear plant joint owners signed a settlement agreement with the U.S. Government (settlement agreement) agreeing to dismiss with prejudice lawsuits filed against the U.S. Government seeking damages caused by the U.S. Department of Energy's failure to dispose of spent nuclear fuel from FPL's and NextEra Energy Resources' nuclear plants. In connection with the settlement agreement, FPL Group established an approximately $153 million ($100 million for FPL) receivable from the U.S. Government and a liability to nuclear plant join owners of $22 million ($5 million for FPL), which are included with other receivables and other current liabilities, respectively, in the condensed consolidated balance sheets at March 31, 2009. In addition, FPL Group reduced its March 31, 2009 property, plant and equipment balances by $107 million ($83 million for FPL) and, for the three months ended March 31, 2009, reduced operating expenses by $15 million ($12 million for FPL) and increased operating revenues by $9 million. The payments due from the U.S. Government under the settlement agreement increased FPL Group's net income for the three months ended March 31, 2009 by approximately $16 million ($9 million for FPL). A substantial portion of the amount due from the U.S. Government is expected during the second quarter of 2009. FPL and NextEra Energy Resources will continue to pay fees to the U.S. Government's nuclear waste fund.**

The Company also described the settlement, providing additional detail, in response to SFHHA Interrogatory 237, a copy of which I have attached as my Exhibit___(LK-15).

Q. How did the Company reflect the results of the DOE settlement in the test year?

A. The Company reflected the reduction in plant in service in the test year rate base, but failed to reflect any reduction in expenses for the ongoing reimbursement from the DOE. In response to SFHHA Interrogatory 237, the Company stated the following:

> **Therefore, the 2010 plant balances used to calculate test year results reflect this estimated reduction and customers will receive the benefits associated with the SNF settlement through future rates. Reductions in prospective costs should likewise occur as DOE reimburses FPL for SNF costs incurred in 2009 and beyond. These refunds were not forecasted in the Test Year and Subsequent Year revenue requirements?**

Q. Should the ongoing DOE refunds be reflected in the test year as a reduction to the revenue requirement?

A. Yes. The failure to reflect the refunds in the test year clearly was an error in the Company's filing given the ongoing nature of the DOE reimbursements resulting from the litigation settlement.

Q. What amount should the Commission reflect in the test year?

A. I recommend that the Commission use the actual $9 million amount reimbursed by the DOE and used by the Company to reduce expense in 2009 as a reasonable estimate for the test year. The revenue requirement effect is $9.030 million.

<u>Customer Accounts and Sales Expense - AMI</u>

Q. Please describe the costs included in the Company's test year revenue requirement for the deployment of AMI meters and related infrastructure.

A. The Company included $7.4 million in account 902 expense for the deployment of its new advanced metering initiative meters and related infrastructure. The Company provided a summary of its deployment schedule and the projected costs to develop the system separated into expense and capital amounts in response to SFHHA Interrogatories 120, 289 and 290. I have attached a copy of each of these responses as my Exhibit___(LK-16), Exhibit___(LK-17) and Exhibit___(LK-18), respectively. The Company described the types of costs expensed by the Company in response to SFHHA Interrogatory 283, a copy of which I have attached as my Exhibit___(LK-19).

Q. How many of the proposed AMI meters will be deployed in the test year?

A. The Company's test year reflects an average of 734,000 meters deployed and a total of 1,298,000 deployed by the end of the test year, according to its response to SFHHA Interrogatory 289. The Company plans to deploy a total of 4,346,000 meters by the end of 2013. Thus, the Company will have deployed 16.9% of the total AMI meters on average during the test year or 30.0% of the total by the end of the test year.

Q. Does the Company expect that the AMI meters will result in expense savings related to the removal of the old non-AMI meters that will offset the increases due to the new AMI meters?

A. Yes. The Company estimates annual expense savings of $36 million after all AMI meters are deployed, according to SFHHA Interrogatory 243, a copy of which I have attached as my Exhibit___(LK-20).

Q. What amount of expense savings has the Company reflected in the test year?

A. The Company has reflected only $0.418 million in expense savings in the test year, according to its response to SFHHA Interrogatory 289 (replicated as my Exhibit__(LK-17). This is only 1.2% of the annualized savings the Company projects upon full deployment.

Q. Is the Company's estimate of savings in the test year reasonable?

A. No. The Company's estimate of 1.2% of the annualized savings compared to the nearly 16.9% of the total investment in rate base for the test year is unreasonable. Upon deployment of these AMI meters, the Company will reduce expenses compared to the levels necessary for its existing non-AMI meters, which include meter reading payroll and related expenses, vehicle expenses, and connect and disconnect expenses, among others, in approximately the same proportion as it has deployed the AMI meters. The Commission should match the savings with the costs and reflect 16.9% of the annualized O&M expense savings consistent with the inclusion in rate base of 16.9% of the cost of the total AMI meters the Company plans to deploy.

Q. Have you quantified the amount of expense savings that should be reflected in the test year?

A. Yes. The Commission should increase the expense savings by $5.666 million to $6.084 million in order to match the savings in expense to the investment included in rate base. I computed this amount by multiplying the 16.9% times the $36 million annualized savings upon full deployment and subtracted the $0.418 million in savings reflected in the Company's projected test year expenses.

Customer Accounts and Sales Expense - CIS

Q. Please describe the expenses included in the Company's test year revenue requirement for the development of a new customer information system.

A. The Company included $7.250 million in account 903 expense and $0.504 in depreciation expense for the development of a new customer information system ("CIS"). The Company provided a summary of its development schedule and the projected costs to develop the system separated into expense and capital amounts in response to SFHHA Interrogatories 287 and 288. I have attached a copy of each of these responses as my Exhibit___(LK-21) and Exhibit___(LK-22), respectively.

The costs the Company included as expense are for the preparation of a detailed project plan, review of scope and preliminary project requirements, approval of scoping study documentation and preparation for data conversion, according to the Company's response to SFHHA Interrogatory 284. I have attached a copy of this response as my Exhibit___(LK-23).

Q. **Should any of the CIS developmental costs be expensed for ratemaking purposes?**

A. No. These costs should be either capitalized to the CIS plant costs or deferred as a regulatory asset for ratemaking purposes rather than expensed in the test year. The Company has determined that the costs should be expensed for accounting purposes, according to its response to SFHHA Interrogatory 284; however, the accounting does not and should not control the ratemaking treatment even assuming that the Company's proposed accounting treatment is correct, which is a matter of judgment. The costs should be capitalized or deferred because they will be incurred for the development of the new CIS, which will be capitalized as intangible plant. The Company will not continue to incur these costs after the new CIS is implemented in June 2012. Thus, the costs are not recurring in nature and should be appended to the CIS capitalized asset or deferred for ratemaking purposes and then depreciated or amortized and recovered over the same expected useful service life as the CIS asset.

Q. **Have you quantified the revenue requirement effect of your recommendation to capitalize or defer this expense?**

A. Yes. The Commission should reduce the revenue requirement by $7.274 million to reflect the reduction in expense. In addition, the Commission should increase the revenue requirement by $0.428 million to reflect the increase in rate base. The computations are detailed on my Exhibit___(LK-24).

Administrative and General Expense – Storm Damage Accrual

Q. **Please describe the Company's proposal to "reestablish" an annual accrual for the Company's storm damage reserve.**

A. The Company proposes to recover through base rates an annual storm damage expense accrual amount of $148.667 million ($150 million total Company). This request has a revenue requirement effect of $149.162 million. The Company presently recovers no storm damage expense through base rates. Instead, the Company presently recovers storm damage expense through a surcharge. The Company does not propose a reduction in the surcharge amounts.

The Company's rate request is sponsored by Company witness Mr. Armando Pimentel, but it is based on a probabilistic loss analysis performed by Company witness Mr. Stephen P. Harris of ABS Consulting using a proprietary probabilistic simulation model.

Q. Please describe the Commission's historic framework for FPL's recovery of its storm damage costs.

A. Prior to its Order approving the settlement of the 2005 rate case, the Commission historically allowed recovery of storm damage costs in base rates through a storm damage expense accrual. This expense amount was recovered from ratepayers and added to the storm damage reserve. When actual storm damage costs were incurred, FPL charged these costs to the reserve, regardless of whether they were costs that normally would be capitalized to plant or expensed and regardless of whether they were "incremental" to costs that already were recovered through base rates.

At any point in time, the storm damage reserve is in either a surplus or a deficiency. The Company's storm damage reserve historically was in a surplus until a series of severe hurricanes and storms in 2004 depleted the reserve and the storm damage reserve became a deficiency. The Commission authorized a provisional storm restoration surcharge in Docket No. 041291-EI, which it affirmed in Order No. PSC-05-0937-FOF-EI, to provide the Company recovery of the reserve deficit over three years. In addition, the Commission required a change in the types of costs that could be charged to the reserve, thus reducing the amount of annual expense accrual and the target reserve levels, all else equal. The Commission determined that only "incremental" storm damage costs could be charged to the reserve. This change meant that costs normally capitalized to plant in service no longer could be charged against the storm damage reserve and were required to be capitalized to plant in service. This change also meant that other costs recovered in base rates could not be charged against the storm damage reserve to avoid recovering the same costs twice.

The Commission also changed the form of storm damage recovery in 2005 by removing all such recoveries from base rates and instead providing all recoveries through a storm damage surcharge rider. In the Company's last base rate increase proceeding, Docket No. 050045-EI, the parties reached a settlement whereby the Company no longer would recover a storm damage expense accrual through base rates. Instead, the Company was permitted to recover its reasonable and prudently incurred storm restoration costs and to replenish the storm damage reserve through a surcharge pursuant to a newly approved securitization financing law (Section 366.8260, Florida Statutes) and/or through a surcharge similar to the one approved for storm damage recovery in 2004. The Commission approved this settlement agreement by Order No. PSC-05-0902-S-EI on September 14, 2005.

The Commission affirmed this change in the form of recovery from base rates to a surcharge in yet another proceeding to recover the Company's storm damage costs that it incurred in 2005. These costs were incurred as the result of several more severe hurricanes that resulted in significant storm damage losses and another storm damage reserve deficiency. To recover these storm damage costs, the Company sought surcharge recovery of the costs based on the issuance of low-cost securitization financing sufficient to recover not only the costs incurred but also to replenish the storm damage reserve. The surcharge in conjunction with securitization financing was made possible by a statute newly enacted for the express purpose of reducing the costs to ratepayers of storm damage loss recovery. In Order No. PSC-06-0464-FOF-EI, the Commission approved a levelized surcharge to recover the securitization and related costs over a 12 year period, approved the recovery of only "incremental" costs despite the Company's request for costs that otherwise would have been capitalized to plant in service or that otherwise were already recovered in base rates, approved the securitization financing, and approved the replenishment of the reserve fund in excess of the storm damage reserve deficiency by $200 million while rejecting the Company's request for $650 million. The Commission summarized its decision in Order No. PSC-06-0464-FOF-EI as follows:

> **In this Financing Order, we find that the issuance of storm-recovery bonds and the imposition of related storm-recovery charges to finance the recovery of FPL's reasonable and prudently incurred storm-recovery costs, the replenishment of FPL's storm-recovery reserve, and related financing costs are reasonably expected to significantly mitigate rate impacts to customers as compared with alternative methods of recovery of storm-recovery costs and replenishment of the storm-recovery reserve.** [Order at 5].

Regarding its decision to limit recovery to only "incremental" storm damage costs, the Commission stated:

> **Under FPL's Actual Restoration Cost Approach, all costs – both normal and incremental – that were related to storm damage activities are charged to FPL's Reserve. We find that the inclusion of**

> **normal costs results in a double recovery, once through base rates and again through the Reserve. Accordingly, we find that an incremental cost approach, including an adjustment to remove normal capital costs, is the appropriate methodology to be used for booking FPL's 2005 storm-recovery costs to its Reserve.** [*Id.*, 17].

Regarding its decision to limit the replenishment of the reserve to $200 million rather than FPL's request for $650 million, the Commission stated the following:

> **Given that FPL has the opportunity to seek recovery of future storm restoration costs through either a surcharge or securitization pursuant to the 2005 Settlement Agreement and applicable law, and given the preference of FPL's customers to face that risk when such costs actually materialize, we decline to approve funding of FPL's Reserve to a level of $650 million through the storm-recovery bonds authorized to be issued under the terms of this Order. We find that funding FPL's Reserve to a level of $200 million is appropriate and will (i) reduce the incidental costs associated with issuance of the storm-recovery bonds authorized to be issued under the terms of this Order, (ii) provide more critical review of FPL's charges to its Reserve, and (iii) result in lower overall storm-recovery charges at this time.** [*Id.*, 25].

Finally, the Commission found that the storm damage surcharge in conjunction with securitization resulted in a significant reduction in the rate impacts to ratepayers compared to more traditional methods of financing or recovering storm-recovery costs and replenishing the reserve. The Commission stated the following:

> **Thus, we find that the issuance of the storm-recovery bonds and the imposition of the storm-recovery charges authorized by this Order are reasonably expected to significantly mitigate rate impacts to customers as compared with alternative, more traditional methods of financing or recovering storm-recovery costs and replenishing the Reserve. Likewise, through implementation of the required standards and procedures established in this Order, we find that the structuring,**

marketing, pricing, and financing costs of the storm-recovery bonds are reasonably expected to significantly mitigate rate impacts to customers as compared with alternative methods of financing or recovery storm-recovery costs and replenishing the Reserve. [*Id.*, 32].

Q. Should the Commission revert to the recovery of storm damage expense through base rates?

A. No. There is no reason for the Commission to revisit its conclusions in the Orders previously cited resulting in the exclusive use of surcharge recoveries in conjunction with securitization to minimize the costs to ratepayers. The Commission should continue to use the surcharge approach in conjunction with securitization of unusually large storm restoration costs resulting in storm damage reserve deficiencies. The use of a surcharge approach in conjunction with securitization provides the Company full and timely recovery of prudently incurred storm damage costs, avoids the need to engage in speculation regarding future storm damage costs, and results in substantially lower costs to ratepayers.

The present storm damage surcharge not only provides the Company recovery of its prior storm damage reserve deficiencies, but also provides recovery of $200 million in future storm damage amounts. That is because the Company's securitization financing provided a "replenishment" of the storm damage reserve in the amount of $200 million. The surcharge is designed to recover the debt service not only to repay FPL for its actual prudently incurred storm restoration costs prior to that date, but also to fund the additional $200 million to the reserve available for future storm damage cost. The Company estimates on MFR

Schedule B-21 that the test year storm damage reserve will have a surplus of $192.966 million after adding the earnings on that $200 million and subtracting charges for subsequent storm damage amounts charged to the reserve since the securitization financing.

To the extent that there are severe storms that deplete this reserve surplus in the future, then the Commission can reset the storm damage surcharge or establish a new surcharge, and authorize the Company to securitize the storm damage reserve deficiency at that time, including amounts necessary to replenish the reserve.

The surcharge approach also avoids the need to engage in speculation over an appropriate storm damage expense amount to include in base rates. The most sophisticated models, including the ABS probabilistic simulation model employed by Company witness Mr. Harris, cannot possibly accurately predict the magnitude or the timing of actual storm damage costs.

Finally, the use of the surcharge approach in conjunction with securitization financing is the least cost and most economically efficient approach. This is true for several reasons. First, the use of the surcharge approach to recover the securitization debt service ensures that there is no tax penalty because the revenues match the expense. In contrast, the recovery of excessive expense accruals through base rates to prefund a surplus in the storm damage reserve results in a tax penalty because such recoveries are included in taxable income, but the expense accrual is not deductible from taxable income (only actual costs incurred are deductible). Under the Company's approach, there is an immediate tax penalty of 38.58% (combined federal and state income tax rate) against the storm damage expense accrual amounts collected through base rates that reduces the amount that can be funded to the reserve. Thus, under the Company's approach, ratepayers are required to make unnecessary payments to the federal and state governments and then are penalized further through a reduction in the actual funds in the storm damage reserve fund that can earn income.

Second, the surcharge approach in conjunction with securitization allows significant savings to ratepayers by using 100% highly rated and lower cost securitization debt instead of financing reserve deficiencies with conventional financing. The costs of conventional financing include a combination of higher cost debt and an even greater cost of common equity, including the income taxes on the return on common equity.

Third, the use of the surcharge approach minimizes the investment the ratepayers must make in the storm damage reserve and the lost return on their investment by comparison to the Company's return on its rate base investment. The earnings on the storm damage reserve funds are extremely low due to the nature of the investments and the need to maintain liquidity. Thus, while ratepayers will be required to pay the Company an 11.80% return before tax on its rate base investments (based on its request in this proceeding), ratepayers will earn only a

7.2% return before tax on their investment in the storm damage reserve fund (based on the Company's trust fund earnings assumptions reflected on MFR Schedule B-21).

Q. If the Commission determines that there should be some amount of storm damage expense recovery through base rates, should it adopt the Company's proposed $148.667 million amount?

A. No. The proposed $148.667 million expense amount is wildly excessive and should be set at $0 if the Commission deems it appropriate to reconsider the form of storm damage expense recovery in this proceeding. First, the proposed amount is based on an insurance-type probabilistic model of risk exposure and replacement property damage. This type of analysis may be appropriate for the insurance industry, but it does not reflect the substance or form of the ratemaking process, or more specifically, this Commission's ratemaking for storm damage costs.

Unlike the insurance companies, it is not necessary for the Company to preemptively recover excessive amounts through rates in order to build up a loss reserve or a "cushion" for potential significant future losses. This is true because the Commission has stated repeatedly in its orders that the Company is entitled to recovery of its reasonable and prudently incurred storm damage costs, regardless of whether there is a sufficient amount in the storm damage reserve. If there is a deficiency, then the Commission historically has allowed the Company to recover the deficiency through a surcharge.

In addition, the analysis performed and the quantification provided by Company witness Mr. Harris is overstated because it is not based on the "incremental" cost for which the Commission allows recovery. Instead, his analysis provides a gross damages estimate comparable to what the Company in prior storm damage proceedings referred to as an "actual restoration cost approach." The Commission rejected this approach in the two most recent storm damage orders that I previously addressed and instead adopted the "incremental" cost approach. The incremental cost approach excludes all costs that otherwise would be capitalized to plant in service and excludes all costs already recovered through base rates, such as the litany of such costs identified and removed by the Commission in its PSC-06-0464-FOF-EI Order.

Finally, the analysis performed by Mr. Harris is overstated because it is based on the Company's proposal for a target reserve surplus of $650 million. The Commission previously rejected that approach and specifically rejected the $650 million target amount and found that a $200 million reserve surplus was reasonable. There is no valid reason for the Commission to revisit its most recent determination on this issue.

<u>Depreciation Expense - New Customer Information System</u>

Q. Please describe the depreciation expense included in the Company's test year for the development of a new customer information system.

A. The Company included $0.504 million in depreciation expense on capitalized plant in service costs for a new CIS. This has a revenue requirement effect of $0.506 million. The Company expects to commence development of the new CIS in January 2010 and to complete and implement it in June 2012. The Company provided a summary of its development schedule in response to SFHHA Interrogatory 287 and the depreciation expense included in the test year revenue requirement in response to SFHHA Interrogatory 288. I have attached a copy of each of these responses as my Exhibit___(LK-21) and Exhibit___(LK-22), respectively.

Q. Should the Company have included depreciation expense for the new CIS in the test year?

A. No. The new CIS is not scheduled to be implemented ("go live") until June 2012, according to its response to SFHHA Interrogatory 287. No amounts should be transferred from construction work in progress to plant in service until the date the new system is placed in service. Consequently, depreciation expense should not commence until June 2012 in accordance with generally accepted accounting principles ("GAAP") and the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA").

<u>Depreciation Expense – Capital Expenditure Reductions</u>

Q. In the Rate Base section of your testimony, you address capital expenditure reductions and the effects on rate base and the revenue requirement. Is there also a related effect on depreciation expense?

A. Yes. A reduction in the plant in service amounts for the test year will result in less depreciation expense than reflected in the Company's projected test year amounts.

Q. Have you quantified the effect of your recommendation?

A. Yes. The effect is to reduce depreciation expense by $26.883 million and to reduce the revenue requirement by $26.719 million. I address the effects on rate base and the resulting reduction in the revenue requirement related to that component in the rate base section of my testimony. The computations are detailed on my Exhibit___(LK-25). I used a composite depreciation rate for all plant accounts to compute the reduction in depreciation expense based on the assumption that the reduction in the plant investment due to capital expenditure reductions was proportional to the Company's plant investment reflected in its depreciation study.

Depreciation Expense – Depreciation Reserve Surplus

Q. Does the Company presently have a depreciation reserve surplus?

A. Yes. Despite the reduction of the Company's reserve surplus over the last four years by $500 million ($125 million annually from 2006 through 2009) as the result of the settlement reached in Docket Nos. 050045-EI and 050188-EI, the

Company still has an estimated reserve surplus of $1,245 million at January 1, 2010. The Company's computations of the reserve surplus are summarized on page 53 of the depreciation study attached to Mr. C. Richard Clarke's Direct Testimony as Exhibit CRC-1. I have attached a copy of this page from the Company's depreciation study as my Exhibit__(LK-26) for reference purposes.

The Company has a depreciation reserve surplus for every functional plant category, except for transmission plant. The following table summarizes the composition of the reserve surplus computed by the Company at December 31, 2009 by functional plant category.

Florida Power & Light Company
Excess Reserve as of December 31, 2009
($ Millions)

Function	Excess Reserve
Steam Generation	410.110
Nuclear Generation	377.507
Combined Cycle Generation	25.945
Combustion Turbine Generation	28.028
Transmission	(15.637)
Distribution	340.529
General	78.879
Total Excess Depreciation Reserve	1,245.360

Q. How should the Commission address the reserve surplus in this proceeding?

A. I recommend that the Commission amortize the reserve surplus over five years in a manner similar to that which it approved in Order No. PSC-05-0902-S-EI approving the settlement in the Company's 2005 rate case. In that proceeding, the Company was allowed to amortize $125 million of its reserve surplus as a reduction to depreciation expense each year from 2006 through 2009 for a cumulative total of $500 million. The Company did so and allocated the amortization over the plant accounts on a *pro rata* basis to reduce the actual depreciation expense and accumulated depreciation recorded on its accounting books each year.

Q. Why is it appropriate to amortize the reserve surplus over a five year period?

A. The Commission should attempt to refund this surplus over a reasonably short period to as closely as possible return the amounts to the ratepayers who overpaid for depreciation expense in prior years based on prior life and salvage estimates. The reserve surplus means that depreciation expense in prior years was excessive compared to present expectations for the service lives, retirements and salvage estimates of plant assets.

Q. Have you quantified the effect of your recommendation?

A. Yes. The effect is to reduce depreciation expense by $246.735 million and to reduce the revenue requirement by $247.556 million. In addition, there is an offsetting increase of $14.559 million in the revenue requirement for the rate of return on the rate base, which will be more than the Company projected due to the reduction in accumulated depreciation. The computations are detailed on my Exhibit___(LK-27).

Depreciation Expense – Capital Recovery

Q. Please describe the Company's request for "capital recovery" of certain plant investment costs.

A. The Company proposes a four year amortization of the net book value of numerous costs as of December 31, 2009. These costs include the remaining undepreciated costs of the Cape Canaveral Units 1 and 2 and common, the Riviera Units 3 and 4 and common; the remaining undepreciated nuclear uprate costs of St. Lucie Units 1 and 2 and Turkey Point Units 3 and 4 and common; and the undepreciated costs of the Company's existing meter investment that will be replaced with advanced meters under the Company's advanced metering initiative ("AMI").

The Company plans to remove the Cape Canaveral facilities from service in 2010 and commence a "modernization" of the facilities as combined cycle units. Similarly, the Company plans to remove the Riviera facilities from service in 2011 and commence a modernization of the Riviera facilities as combined cycle units. The Company simply proposes to amortize the nuclear uprate costs over four years with no rationale provided by any witness. Finally, the Company plans to amortize the remaining investment in its existing meters over four years due to its planned AMI meter deployment.

The following table summarizes the net book value at December 31, 2009 of each of these capital recovery costs and the Company's proposed depreciation expense based on a four year capital recovery period.

Florida Power & Light Company
Unrecovered Capital Costs as of December 31, 2009
($ Millions)

Description	Unrecovered Costs
Cape Canaveral Common	3.539
Cape Canaveral Unit 1	23.148
Cape Canaveral Unit 2	8.616
Riviera Common	0.057
Riviera Unit 1	5.664
Riviera Unit 2	3.883
St. Lucie Unit 1	40.821
St. Lucie Unit 2	37.448
Turkey Point Common	2.149
Turkey Point Unit 3	43.931
Turkey Point Unit 4	43.886
Acct 370 Meters Made Obsolete by AMI	101.082
Total Unrecovered Costs	314.223

Q. **Should the Commission authorize depreciation over a four year period for the undepreciated costs of the Cape Canaveral and Riviera facilities?**

A. No. The Commission should direct the Company to cease depreciation on these facilities, add the remaining net book value to the costs of the modernization, and then depreciate the costs along with the modernization costs over the estimated service lives of the modernized facilities. The Company's witnesses have offered no valid rationale to accelerate the recovery of these capital costs to four years.

To the extent the facilities are retired for property accounting purposes, the retirement amounts will be used to reduce gross plant in service and accumulated depreciation by the same amounts in accordance with GAAP and the FERC USOA. In this manner, the remaining net plant associated with these facilities will be reflected as an asset amount of accumulated deprecation. In addition, depreciation expense will cease because there no longer will be any gross plant in service.

Once the modernization is completed, then the Commission should allow the Company to recover both the modernization costs and the asset accumulated depreciation related to the retired assets over the expected service lives of the new facilities. This is similar in concept to the cost of reacquiring debt and replacing it with lower cost debt. In that situation, the cost of reacquiring the old debt is deferred and then amortized over the life of the new debt issue.

Alternatively, the Commission should direct the Company to defer the net remaining book value at December 31, 2009 and then amortize the deferred amounts using the existing depreciation rates.

Q. Should the Commission authorize depreciation over a four year period for the nuclear uprate costs incurred through December 31, 2009?

A. No. The Commission should depreciate these costs over the remaining extended license life of the nuclear units. These costs are capital costs that were incurred to substantially improve and increase the output of the nuclear facilities over their extended lives. There is no valid reason that these capital costs should be segregated from the other capital costs of these facilities and depreciated over any period shorter than their estimated useful service lives in the same manner as any other capitalized plant cost.

Q. Should the Commission authorize depreciation over a four year period for the existing meter investment?

A. No. The Commission should use the same depreciation or amortization rate for these costs as it adopts for the remaining existing meter investment that will not be replaced by AMI meters. There is no valid reason to accelerate the recovery of the Company's existing meter investment, particularly when the Company's revenue requirement also includes the costs of the replacement AMI meters. The Company's proposal has the effect not only of "doubling up" the recovery of old non-AMI and new AMI meter investment, but also of accelerating the recovery of the old meter investment from the present recovery using a 3.26% depreciation rate to a 25% depreciation rate.

Q. Have you quantified the effect of your recommendations on the Company's proposed capital recovery amounts?

A. Yes. The effect is to reduce depreciation expense by $63.394 million and to reduce the revenue requirement by $63.605 million for the three capital recovery components. In addition, there is an offsetting increase in the revenue requirement of $3.741 million to reflect the return on rate base resulting from the reduction in accumulated depreciation compared to the Company's requested rate base amount. The expense and rate base revenue requirement effects are shown separately in the table in the Summary section of my testimony. The computations are detailed on my Exhibit___(LK-28).

Depreciation Expense – Service Lives

Q. Please describe the Company's proposed service lives used to develop the depreciation rates and depreciation expense for its combined cycle generating facilities, including WCEC 1 and 2, reflected in its requested test year revenue requirement and for the WCEC 3 facilities reflected in its proposed GBRA.

A. The Company proposes a service life of 25 years for all such facilities, except for those that would be retired prior to June 2020 if it had continued to use that service life assumption for those facilities, or ten years after the test year, according to the depreciation study attached to the Direct Testimony of C. Richard Clarke as his Exhibit CRC-1. The Company offered no support for the proposed 25 year service life.

Q. **Is the Company's proposed 25 year service life reasonable?**

A. No. I recommend a 40 year service life. The service life used for depreciation purposes should reflect the expected useful life of the facility, not some arbitrary shorter period. The Company proposes depreciation rates assuming 25 year service lives based on probable retirement dates 25 years after the commercial in-service dates for its combined cycle units with the exception of the Putnam units.

The Putnam 1 unit went into commercial operation in 1977 and Putnam 2 in 1978, according to the Company's FERC Form 1. I have attached a copy of page 402 from the Company's 2008 Form 1 filing as my Exhibit___(LK-29). The Company originally claimed that the units had a service life of 25 years for depreciation purposes and the Commission set depreciation rates based on that assumption. However, Putnam 1 was not retired in 2002 and Putnam 3 was not retired in 2003, their respective 25th anniversary dates and the assumed end of their service lives. Instead, the Company continues to operate both units. The Company now asserts that the Putnam 1 and 2 units both have a probable retirement date of June 2020 for depreciation purposes, which means that the Company has no plans to retire the units before that date and may continue to operate the units beyond that date. The June 2020 retirement date indicates that the Putnam 1 unit has a service life of at least 43 years and Putnam 2 of at least 42 years. The Company provided this information on page 132 of Company witness Mr. C. Richard Clarke's Exhibit CRC-1, the Company's depreciation study. I have attached a copy of this page as my Exhibit___(LK-30) for reference purposes. These probable retirement dates for the Putnam units demonstrate that in reality the Company's combined cycle units have service lives of at least 40 years.

In addition to the experience of the Company's own units, other utilities use a 40 year service life for planning and depreciation purposes. For example, PacifiCorp uses a 40 year life for its combined cycle combustion turbine facilities. I have attached a copy of the cover and the relevant page from PacifiCorp's 2008 IRP, which shows PacifiCorp's service life assumptions for such facilities used in its resource planning process, as my Exhibit___(LK-31).

Finally, as a practical matter, utilities do not retire generating units if they remain economic to generate. Thus, the Commission should assume that the Company will continue to operate these units for at least 40 years unless the Company can demonstrate conclusively that they will be operated only for 25 years.

Q. **Have you quantified the effect of your recommendation?**

A. Yes. The effect is to reduce depreciation expense by $123.319 million and to reduce the revenue requirement by $123.730 million. In addition, there is an offsetting increase in the revenue requirement of $7.726 million to reflect the return on rate base resulting from the reduction in accumulated depreciation compared to the Company's requested rate base amount. The expense and rate base revenue requirement effects are shown separately in the table in the Summary section of my testimony. The computations are detailed on my Exhibit___(LK-32).

<u>Income Tax Expense – Economic Stimulus Bill</u>

Q. Has the Company reflected any of the tax benefits resulting from the federal Economic Stimulus Bill in its filing?

A. No. Company witness Ms. Ousdahl acknowledged that "many provisions of the bill are effective for the 2009 tax year," but stated that "[a] this time, the Company has not quantified or captured the potential benefits." [Ousdahl Direct at 36].

Q. Should the tax benefits resulting from the American Recovery and Reinvestment Act of 2009 ("Stimulus Bill") be reflected in the Company's revenue requirement?

A. Yes. There are numerous provisions that provide grants or other subsidies for utility investment in generation, transmission and distribution infrastructure. Many of the provisions are effective already in 2009 and extend into subsequent years.

Q. Should these tax benefits be reflected in the Company's revenue requirement?

A. Yes. At a minimum, the Commission should reflect a $20 million grant available to the Company to reduce the costs of advanced (AMI) meters and other smart grid investment. The Company's filing includes the costs of deploying advanced meters and the related smart grid infrastructure. It is axiomatic that any grants or other savings resulting from that deployment should be used to reduce the costs included in the revenue requirement.

The Stimulus Bill modified the provisions of the Energy Independence and Security Act ("EISA") of 2007 addressing smart grid technology deployment. Section 405 of the Stimulus Bill modified Section 1304 of the EISA to provide a subsidy of up to 50% (up from 20% under EISA) of the cost of smart grid technology deployment in the form of grants to utilities for qualified costs. The Department of Energy ("DOE") issued a draft notice of its "Funding Opportunity Announcement (FOA) for the Smart Grid Investment Grant Program" providing for grants of up to $20 million for this purpose, although I was recently informed by an AEP employee in another rate proceeding that the $20 million cap has been removed and more grant funds are available.

Q. Has the Company applied to the DOE for the matching grants for smart grid investment?

A. Yes. The website www.smartmeter.com reported on April 20, 2009 that FPL planned to install a million fully functioning "smart meters" for all Miami residents within the next two years. The article reported that "[t]he utility is applying for a matching grant from the stimulus package that Hay [FPL CEO Lewis Hay] says will allow FP&L to complete the project within two years." I have attached a copy of the article as my Exhibit___(LK-33).

Q. Should the Commission incorporate this benefit in the revenue requirement even if the Company has not yet received grant funds?

A. Yes. The entire test year is a projection of the Company's revenues and costs based on assumptions. The Commission should assume that the Company will seek these funds and obtain the maximum amount available to individual utilities. The alternative is to assume that the Company will not seek these funds and/or will not obtain any funding. On the spectrum of possibilities, the probability of the former, while not certain because it represents an assumption regarding the future, is far greater than the latter. Alternatively, but with essentially the same result, the Commission could exclude at least $20 million from the Company's proposed rate base and the related depreciation expense and instead allow the Company to defer $20 million of its AMI deployment costs to this account rather than capitalizing it to plant in service. The deferred asset amount then would be reduced by the entirety of any grants received from the DOE. Any residual (positive or negative) could be included by the Company in rate base in a future rate proceeding.

Q. Have you quantified the effect of your recommendation to include the DOE smart grid grant of $20 million?

A. Yes. The effect is to reduce the Company's proposed revenue requirement by $3.846 million. I quantified this effect in two steps. First, I computed the reduction in depreciation expense by applying the Company's proposed depreciation rate for the new AMI meters of 7.97% to the $20 million grant amount. This had the effect of reducing depreciation expense by $1.579 million on a jurisdictional basis and reducing the revenue requirement by $1.584 million. Second, I computed the reduction in the return by multiplying the Company's proposed 11.80% grossed-up rate of return times the net reduction in rate base of $19.210 million (reflecting half year of depreciation expense in accumulated depreciation). This had the effect of reducing the Company's revenue requirement by an additional $2.267 million. The computations are detailed on my Exhibit___(LK-34).

Q. How should the Commission address other tax benefits resulting from the Stimulus Bill?

A. The Commission should direct the Company to capture and defer as a regulatory liability all tax benefits that obtained, but for which the Company failed to reflect the estimated savings in its requested revenue requirement. The Commission then should use these amounts to reduce the Company's revenue requirement in a subsequent rate proceeding. The Commission should require that the Company document these tax benefits along with its efforts to maximize the value of those tax benefits for the Commission's review in a subsequent rate proceeding.

III. RATE BASE ISSUES

Capital Expenditure Reductions Since Budgets/Forecasts Were Developed

Q. Has the Company cut its actual capital expenditures significantly from budgeted levels to date in 2009?

A. Yes. For the first four months of 2009, the Company cut its capital expenditures by $170 million from budget levels, from $897 million to $727 million. This is a reduction of 19.0% or $529 million on an annual basis compared to the Company's $2,790 million 2009 capital expenditure budget. The actual and budget amounts were provided in response to SFHHA Interrogatory 279, a copy of which I have attached as Exhibit___(LK-35). These reductions are in addition to $469 million in capital expenditure reductions already incorporated in the 2009 approved budget compared to the 2009 proposed budget, according to FPL witness Barrett's Exhibit REB-16.

Q. Should the Commission reflect these cost reductions in the 2010 test year revenue requirement?

A. Yes. The Company's plant investment included in rate base should be reduced to reflect these capital expenditure reductions on an annualized basis, both for the annualized 2009 reductions carried forward into 2010 and for reductions of similar magnitude in 2010.

Q. Have you quantified the effect of your recommendations?

A. Yes. The effect is to reduce gross plant included in rate base by $784 million and the revenue requirement by $92.520 million based on the Company's proposed rate of return. In addition, there is an offsetting reduction to accumulated depreciation that increases rate base by $31.080 million and increases the revenue requirement by $3.668 million. The computations are detailed on my Exhibit___(LK-25). I discuss the related depreciation expense effect in the Operating Income section of my testimony.

Capital Recovery and Related Accumulated Depreciation

Q. Have you quantified the effect of your depreciation expense recommendations on rate base and the related revenue requirement?

A. Yes. The effect of this issue is to reduce rate base by $31.697 million and the revenue requirement by $3.741 million. The quantifications are detailed on my Exhibit___(LK-28). I discuss the related depreciation expense effects in the Operating Income section of my testimony.

Depreciation Lives and Related Accumulated Depreciation

Q. Have you quantified the effect of your depreciation expense recommendations on rate base and the related revenue requirement?

A. Yes. The effect of this issue is to increase rate base by $61.660 million and the revenue requirement by $7.276 million. The quantifications are detailed on my Exhibit___(LK-32). I discuss the related depreciation expense effects in the Operating Income section of my testimony.

IV. CAPITAL STRUCTURE AND RATE OF RETURN ISSUES

Capital Structure – Common Equity

Q. **SFHHA witness Mr. Richard Baudino recommends adjustments to the Company's proposed capital structure that reduce the common equity ratio and increase the debt ratio used to develop the rate of return applied to rate base. Have you quantified the effect of Mr. Baudino's recommendation?**

A. Yes. The effect is to reduce the Company's revenue requirement by $121.424 million. I computed the revenue requirement effect in three steps. First, I computed the Company's requested rate of return grossed-up for income taxes on the equity component. Second, I computed Mr. Baudino's adjusted rate of return grossed-up for income taxes on the equity component. Third, I computed the revenue requirement by multiplying the difference in the two rates of return times the rate base that I recommend. The computations are detailed on my Exhibit___(LK-36) in Sections I and II.

Capital Structure – Short Term Debt

Q. **SFHHA witness Mr. Baudino recommends adjustments to the Company's proposed capital structure that increase the short term debt ratio and reduce the long term debt ratio used to develop the rate of return applied to rate base. Have you quantified the effect of Mr. Baudino's recommendation?**

A. Yes. The effect is to reduce the Company's revenue requirement by $11.018 million in addition to the reduction from the first of Mr. Baudino's capital structure recommendations. I computed the revenue requirement effect in the same manner as for the first of Mr. Baudino's recommendations. The computations are detailed on my Exhibit___(LK-36) in Sections II and III.

Capital Structure – Accumulated Deferred Income Taxes Related to FIN 48

Q. Should the Commission increase the amount of accumulated deferred income taxes reflected in the Company's proposed capital structure?

A. Yes. The Company inappropriately has reduced the ADIT included in its proposed capital structure by $168.598 million for the effects of FIN 48. The Company provided this amount in response to SFHHA Interrogatory No. 278, a copy of which I have attached as my Exhibit___(LK-37). FIN 48 is a new accounting standard that was implemented by the Company in 2007. FIN 48 requires the Company to establish a "reserve" for future income tax audit adjustments that may increase the Company's income tax liability and thus reduce the ADIT recorded on its accounting books. The FIN 48 adjustment reduces the net liability ADIT reflected in the Company's proposed capital structure as cost free capital.

Q. Why should the Commission restore the full amount of the net liability ADIT and exclude the FIN 48 adjustment in the capital structure?

A. There are several reasons. First, the FIN 48 adjustment does not actually reduce the Company's cost free capital. It is nothing more than the Company's educated guess at the outcome of the Company's future tax audits for deductions that already have been taken and that already are reflected in its tax returns. Second, if the Company's educated guess was pessimistic, then there never will be a ratepayer true-up for the lost return because of the assumption that the Company had less cost-free capital than it actually had. Third, the Commission has not previously reduced the Company's ADIT for potential future audit adjustments. Fourth, to the extent that there are future audit adjustments that actually reduce the tax benefits reflected in the ADIT amounts, then the per books amounts will be properly reduced for those effects in future rate proceedings. Thus, the Company's adjustment is speculative at best, and completely unnecessary as the Company will be fully protected if and when there are actual audit adjustments.

Q. **Have you quantified the revenue requirement effect of your recommendation?**

A. Yes. The effect is to reduce the Company's revenue requirement by $17.643 million in addition to the reductions due to Mr. Baudino's capital structure recommendations. To compute this effect, I increased the ADIT included in the capital structure by the FIN 48 amount, computed the difference between the resulting grossed-up rate of return and the grossed-up rate of return reflecting only Mr. Baudino's capital structure adjustments and then multiplied this difference times the rate base that I recommend. The computations are detailed on my Exhibit___(LK-36) in Sections III and IV.

Capital Structure – Customer Deposits and Accumulated Deferred Income Taxes

Q. **Are there other adjustments that should be made to the Company's proposed capital structure?**

A. Yes. The Company has improperly diluted the low-cost capital provided by customer deposits and the cost-free capital provided by ADIT by allocating the sum of the prorata adjustments to these capital components.

Q. **Why is this improper?**

A. These capital amounts should be directly assigned to ratepayers in the same manner as if the amounts had been used to reduce rate base. Customer deposits and ADIT were not used to finance the amounts that comprise the total of the prorata adjustments detailed on MFR Schedule D-1B. The prorata adjustments detailed on MFR Schedule D-1B are primarily to reconcile the total capitalization to rate base, which excludes certain construction work in progress and the capital costs recovered through various riders.

Q. **Have you quantified the revenue requirement effect of your recommendation?**

A. Yes. The effect is to reduce the Company's revenue requirement by $48.695 million in addition to the reductions due to the SFHHA capital structure recommendations that I previously quantified. To compute this effect, I reallocated the prorata adjustments to all capital components except customer deposits, ADIT and investment tax credits. I then computed the difference between the resulting grossed-up rate of return and the grossed-up rate of return reflecting the prior SFHHA capital structure recommendations and multiplied this difference times the rate base that I recommend. The computations are detailed on my Exhibit___(LK-36) in Sections IV and V.

Capital Structure – Accumulated Deferred Income Taxes Related to Changes in Depreciation Expense

Q. Is it necessary to change the ADIT included in the capital structure to reflect the changes in depreciation expense and accumulated depreciation that your recommend?

A. Yes. If depreciation expense and accumulated depreciation are reduced from the levels proposed by the Company for the adjustments to those amounts that I previously discussed, then there also must be an increase to the related ADIT compared to the levels proposed by the Company in the capital structure. In other words, a reduction in depreciation expense results in an increase in deferred income tax expense and thus, an increase in ADIT.

Q. Have you quantified the revenue requirement effect of your recommendation?

A. Yes. The effect is to reduce the Company's revenue requirement by $8.909 million in addition to the reductions due to the SFHHA capital structure recommendations that I previously quantified. To compute this effect, I increased the ADIT by multiplying the Company's 38.58% combined federal and state income tax rate times the net reduction in accumulated depreciation resulting from my depreciation expense recommendations. I then computed the difference between the resulting grossed-up rate of return and the grossed-up rate of return reflecting the prior SFHHA capital structure recommendations and multiplied this difference times the rate base that I recommend. The computations are detailed on my Exhibit___(LK-36) in Sections V and VI.

Return on Common Equity

Q. Have you quantified the revenue requirement effect of SFHHA witness Mr. Baudino's return on equity recommendation?

A. Yes. The effect is to reduce the Company's revenue requirement by $232.610 million in addition to the reductions due to the SFHHA capital structure recommendations that I previously quantified. To compute this effect, I substituted Mr. Baudino's return on equity for the Company's requested 12.50% return on equity. I then computed the difference between the resulting grossed-up rate of return and the grossed-up rate of return reflecting the prior SFHHA capital structure recommendations and multiplied this difference times the rate base that I recommend. The computations are detailed on my Exhibit___(LK-36) in Sections VI and VII.

Cost of Short-Term Debt

Q. Have you quantified the revenue requirement effect of SFHHA witness Mr. Baudino's cost of short term debt recommendation?

A. Yes. The effect is to reduce the Company's revenue requirement by $11.785 million in addition to the reductions due to the SFHHA capital structure and return on equity recommendations that I previously quantified. To compute this effect, I substituted Mr. Baudino's proposed 0.60% cost of short term debt for the Company's 2.96% cost of short term debt. I then computed the difference between the resulting grossed-up rate of return and the grossed-up rate of return reflecting the prior SFHHA capital structure recommendations and multiplied this difference times the rate base that I recommend. Finally, I offset this reduction due only to the interest rate differential to include the $1.661 million in annual interest expense for the facility and administrative fees for the Company's credit term loan facilities, which increases the Company's interest expense to include these fees and increases the revenue requirement. I obtained these amounts from the Company's response to SFHHA Interrogatory 280, a copy of which I have attached as my Exhibit___(LK-38). Mr. Baudino addresses the reasons why the Commission should exclude the facility and administrative fees from the interest rate applied to rate base and instead add the expense separately to the revenue requirement. The computations are detailed on my Exhibit___(LK-36) in Sections VII and VIII.

Q. Does this complete your testimony?

A. Yes.

Public Disclosure Version

**BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION**

IN RE:

PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	))	**DOCKET NO. 080677-EI**

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

**J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA**

JULY 2009

EXHIBIT __ (LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

More than thirty years of utility industry experience in the financial, rate, tax, and planning areas. Specialization in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition and diversification. Expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present:

J. Kennedy and Associates, Inc.: Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986:

Energy Management Associates: Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983:

The Toledo Edison Company: Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

RESUME OF LANE KOLLEN, VICE PRESIDENT

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
Gallatin Steel
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Cities in Texas-New Mexico Power Company's Service Territory
Cities in AEP Texas Central Company's Service Territory
Cities in AEP Texas North Company's Service Territory
Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

RESUME OF LANE KOLLEN, VICE PRESIDENT

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

**Expert Testimony Appearances
of
Lane Kollen
As of June 2009**

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements. Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General	Big Rivers Electric	Financial workout plan.

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			Div. of Consumer Protection	Corp.	
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric Corp.	Financial workout plan.
5/88	M-87017 -1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017 -2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017- -1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92
7/88	M-87017- -2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92

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Date	Case	Jurisdict.	Party	Utility	Subject
	Rebuttal				
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800 355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71)
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.

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7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA	Louisiana Public	Gulf States	Fuel clause, gain on sale

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Date	Case	Jurisdict.	Party	Utility	Subject
		19th Judicial District Ct.	Service Commission	Utilities	of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231 -E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.

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Date	Case	Jurisdict.	Party	Utility	Subject
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.,	OPEB expense, deferred fuel, CWIP in rate base

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Date	Case	Jurisdict.	Party	Utility	Subject
				Bethlehem Steel Corp.	
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
3/93	93-01 EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission	Gulf States Utilities/Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities/Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Nuclear and fossil unit performance, fuel costs, fuel clause principles and

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Date	Case	Jurisdict.	Party	Utility	Subject
					guidelines.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Band, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co. The Cleveland Electric Illuminating Co.	Competition, asset writeoffs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC No. 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.

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Date	Case	Jurisdict.	Party	Utility	Subject
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. and Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory

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Date	Case	Jurisdict.	Party	Utility	Subject
			Group		assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements,

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Date	Case	Jurisdict.	Party	Utility	Subject
					securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
4/99	99-02-05	CT	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities stranded costs, recovery mechanisms.
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co. and Kentucky Utilities Co.	Alternative regulation.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, and American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost; T&D revenue requirements.
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/99	21527	TX	Dallas-Ft.Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
04/00	99-1212-EL-ETP OH 99-1213-EL-ATA 99-1214-EL-AAM		Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
07/00	22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated

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Date	Case	Jurisdict.	Party	Utility	Subject
			Staff		affiliates, ratemaking adjustments.
10/00	PUC 22350 SOAH 473-00-1015	TX	The Dallas-Ft. Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp/	Merger, savings, reliability.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. and Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, Separations methodology.
07/01	U-21453, U-20925, U-22092 Subdocket B Transmission and Distribution Term Sheet	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01	U-25687	LA	Louisiana Public	Entergy Gulf States, Inc.	Revenue requirements, capital structure,

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Date	Case	Jurisdict.	Party	Utility	Subject
	Direct		Service Commission Staff		allocation of regulated and nonregulated costs, River Bend uprate.
02/02	25230	TX	Dallas Ft.-Worth Hospital Council & the Coalition of Independent Colleges & Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02	U-25687 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 and U-22092 (Subdocket C)		Louisiana Public Service Commission Staff	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
06/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and The Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.

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Date	Case	Jurisdict.	Party	Utility	Subject
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, and ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, and ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Unit power purchase and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year

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					adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.
03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	SOAH Docket 473-04-2459, PUC Docket 29206	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including including valuation issues, ITC, ADIT, excess earnings.
05/04	04-169-EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.
08/04	SOAH Docket 473-04-4556 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	Docket No. U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/04	Docket No. U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements.
12/04	Case No. 2004-00321 Case No. 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, etal.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and § 199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.

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Date	Case	Jurisdict.	Party	Utility	Subject
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas and Electric Co.	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider. Net Congestion Rider, Storm damage, vegetation management program, depreciation, off-system sales, maintenance normalization, pension and OPEB.
03/06 05/06	31994 31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or charge. Retrospective ADFIT, prospective ADFIT.
03/06	U-21453, U-20925, U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
3/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPoint Energy Houston Electric	Proposed Regulations affecting flow-through to ratepayers of excess deferred income taxes and investment Tax credits on generation plant that is sold or deregulated.
4/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated programs costs, storm damage costs.
07/06	U-23327	LA	Louisiana Public Service Commission	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.

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Date	Case	Jurisdict.	Party	Utility	Subject
08/06	U-21453, U-20925 U-22092 (Subdocket J)	LA	Staff Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.
12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co..	Revenue requirements, formula rate plan, banking proposal.
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
03/07	33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery.
04/07	U-29764 Supplemental And Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts
04/07	ER07-684-000	FERC	Louisiana Public	Entergy Services, Inc.	Fuel hedging costs and compliance

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Date	Case	Jurisdict.	Party	Utility	Subject
	Affidavit		Service Commission	and the Entergy Operating Companies	with FERC USOA.
05/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000	FERC	Louisiana Public Service	Entergy Services, Inc.	Functionalization and allocation of

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Date	Case	Jurisdict.	Party	Utility	Subject
	Direct		Commission	and the Entergy Operating Companies	Intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuctionalization and allocation of intangible and general plant and A&G expenses.
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue Requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses in account 923; storm damage expense and accounts 924, 228.1, 182.3, 254 and 407.3; tax NOL carrybacks in account 165 and 236; ADIT; nuclear service lives and effect on depreciation and decommissioning.
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses in account 923; storm damage expense and accounts 924, 228.1, 182.3, 254 and 407.3; tax NOL carrybacks in account 165 and 236; ADIT; nuclear service lives and effect on depreciation and decommissioning.
04/08	2007-00562 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Panel with Thomas K. Bond, Cynthia Johnson, Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Panel with Thomas K. Bond, Cynthia Johnson, Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.

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Date	Case	Jurisdict.	Party	Utility	Subject
05/08	26837 Supplemental Rebuttal Panel with Thomas K. Bond, Cynthia Johnson, Michelle Thebert	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, incl costs recovered in existing rates, TIER
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, incl projected test year rate base and expenses.
07/08	27163 Panel with Victoria Taylor	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
09/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.
09/08	08-935-EL-SSO 08-918-EL-SSO	OH OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-564 2007-565	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky	Revenue forecast, affiliate costs, depreciation expenses, federal and state

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Date	Case	Jurisdict.	Party	Utility	Subject
	2008-251 2008-252			Utilities Company	Income tax expense, capitalization, cost of debt.
11/08	EL-08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
11/08	35717	TX	Cities Served by Oncor Delivery Company	Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.
02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Revenue requirements.
03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
03/09	U-21453,U-20925 U-22092 (Subdocket J)		Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	U-21453, U-20925 U-22092 (Subdocket J) Rebuttal		Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	2009-00040 Direct-Interim	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.
04/09	36530	TX	State Office of Administrative	Oncor Electric Delivery	Rate case expenses.

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			Hearings	Company, LLC	
05/09	ER08-1056 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
06/09	2009-00040 Direct-Permanent	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements, TIER, cash flow.

EXHIBIT___(LK-2)

Florida Power & Light Company
Docket No. 080677-EI
SFHHA's Second Set of Interrogatories
Interrogatory No. 112
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Q.
Interrogatories Directed to Ms. Kim Ousdahl:

Regarding Page 12:8-Page 13:13. Please explain why in FPL's view it would be appropriate to increase rates through the GBRA mechanism to recover costs associated with placing a new generating plant in service, but not to take into account at the same time adjustments that would have an opposite effect on rates, such as accumulated depreciation, increases in billing determinants, and/or reductions to other elements in FPL's cost of service.

A.
Generating plant additions represent a significant capital investment that results in large, lump sum increases to rate base and revenue requirements that often, in and of itself, will result in the need to file for a base rate increase. Other types of utility activities such as accumulated depreciation, increases in billing determinants and/or reductions to other elements of cost of service tend to occur gradually over time and are offset by increases in O&M expense, increases in capital expenditures for capital replacement of existing plants, new service accounts, system reliability, storm hardening with corresponding increase in depreciation expense. Attempting to address all changes in costs during the GBRA process would effectively turn that process into a full base rate case proceeding. The GBRA process was initiated, in part, to reduce the frequency of expensive, resource intensive full requirements base rate cases.

EXHIBIT___(LK-3)

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company.	DOCKET NO. 050045-EI
In re: 2005 comprehensive depreciation study by Florida Power & Light Company.	DOCKET NO. 050188-EI ORDER NO. PSC-05-0902-S-EI ISSUED: September 14, 2005

The following Commissioners participated in the disposition of this matter:

BRAULIO L. BAEZ, *Chairman*
J. TERRY DEASON
RUDOLPH "RUDY" BRADLEY
LISA POLAK EDGAR

ORDER APPROVING STIPULATION AND SETTLEMENT

BY THE COMMISSION:

I. BACKGROUND

On March 22, 2005, Florida Power & Light Company (FPL) filed a petition for approval of a permanent increase in rates and charges sufficient to generate additional total annual revenues of $430,198,000 beginning January 1, 2006, and for approval of an adjustment to 2007 base rates to produce additional annual revenues of $122,757,000 beginning 30 days following the commercial in-service date of Turkey Point Unit 5 projected to occur in June 2007. In support of its petition, FPL filed new rate schedules, testimony, Minimum Filing Requirements (MFRs), and other schedules. FPL's petition was assigned Docket No. 050045-EI. By Order No. PSC-05-0619-PCO-EI, issued June 6, 2005, we suspended FPL's proposed new rate schedules to allow our staff and intervenors sufficient time to adequately and thoroughly examine the basis for the proposed new rates.

On March 17, 2005, FPL filed a depreciation study for this Commission's review. The depreciation study was assigned Docket No. 050188-EI. By Order No. PSC-05-0499-PCO-EI, issued May 9, 2005, we consolidated Docket Nos. 050188-EI and 050045-EI for all purposes.

As part of this consolidated proceeding, we conducted service hearings at the following locations in FPL's service territory: Daytona Beach, Viera, West Palm Beach, Ft. Lauderdale, Miami, Sarasota, and Ft. Myers. A formal administrative hearing was scheduled for August 22 - 26 and August 31 - September 2, 2005. The Office of Public Counsel (OPC), Office of the Attorney General (AG), Florida Industrial Power Users Group (FIPUG), Florida Retail Federation (FRF), Commercial Group (CG), AARP, Federal Executive Agencies (FEA), and

South Florida Hospital and Healthcare Association (SFHHA) were granted intervenor status. Common Cause Florida and seven individual customers filed a petition to intervene on August 15, 2005.

On August 22, 2005, the parties filed a joint motion for approval of a Stipulation and Settlement[1] among all parties to resolve all matters in this consolidated proceeding.[2] The Stipulation and Settlement was presented at the start of our hearing on August 22. The hearing was recessed to allow our staff to thoroughly review the Stipulation and Settlement and provide its analysis to us on August 24, when the hearing was reconvened for our vote.

By this Order, we approve the Stipulation and Settlement. Jurisdiction over these matters is vested in this Commission by various provisions of Chapter 366, Florida Statutes, including Sections 336.04, 366.05, and 366.06, Florida Statutes.

II. STIPULATION AND SETTLEMENT

The major elements contained in the Stipulation and Settlement are as follows:

- The Stipulation and Settlement is effective for a minimum term of four years - January 1, 2006, through December 31, 2009 - and thereafter will remain in effect until new base rates and charges become effective by order of the Commission. (Paragraph 1)

- With the exception of certain new and modified rate schedules specified in the Stipulation and Settlement, FPL's retail base rates and charges will remain unchanged on January 1, 2006, when the currently operative stipulation governing FPL's base rates and charges expires. (Paragraph 2)

- No party will petition for a change in FPL's base rates and charges to take effect prior to the minimum term of the Stipulation and Settlement, and, except as provided for in the Stipulation and Settlement, FPL will not petition for any new surcharges to recover costs that traditionally would be, or are presently, recovered through base rates. (Paragraph 3)

- A revenue sharing plan similar to the one contained in FPL's currently operative rate settlement will be implemented through the term of the Stipulation and Settlement. Retail base rate revenues between specified sharing threshold amounts and revenue caps will be shared as follows: FPL's shareholders will receive a 1/3 share, and FPL's retail customers will receive a 2/3 share. Retail base rate revenues above the specified revenue caps will be refunded to retail customers on an annual basis. (Paragraphs 4 and 5)

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[1] The Stipulation and Settlement is attached hereto as Attachment A and is incorporated herein by reference.

[2] Although Common Cause Florida and the individual customers had not been granted intervenor status, they signed the stipulation and settlement along with all parties. Under these circumstances and without objection from any party, we found at the August 22 hearing that it was not necessary to make a ruling on the petition to intervene filed by Common Cause Florida and the individual customers.

- If FPL's retail base rate earnings fall below a 10% ROE as reported on a Commission-adjusted or pro-forma basis on an FPL monthly earnings surveillance report during the term of the Stipulation and Settlement, FPL may petition to amend its base rates, and parties to the Stipulation are not precluded from participating in such a proceeding. This provision does not limit FPL from any recovery of costs otherwise contemplated by the Stipulation. (Paragraph 6)

- FPL has the option to amortize up to $125,000,000 annually as a credit to depreciation expense and a debit to the bottom line depreciation reserve over the term of the Stipulation and Settlement and as specified therein. Depreciation rates and/or capital recovery schedules will be established pursuant to the comprehensive depreciation studies as filed in March 2005 and will not be changed during the term of the Stipulation and Settlement. (Paragraph 8)

- Subject to review for prudence and reasonableness, FPL is permitted clause recovery of incremental costs associated with establishment of a Regional Transmission Organization or costs arising from an order of this Commission or the Federal Energy Regulatory Commission addressing any alternative configuration or structure to address independent transmission system governance or operation. (Paragraph 9)

- No party will appeal the Commission's final order in Docket No. 041291-EI addressing recovery of 2004 storm recovery costs. FPL will suspend its current accrual to its storm reserve effective January 1, 2006. Through a separate proceeding, a target level for FPL's storm reserve will be set. Replenishment of the storm reserve to that target level shall be accomplished through securitization under Section 366.8260, Florida Statutes, or through a separate surcharge that is independent of and incremental to retail base rates, as approved by the Commission. (Paragraph 10)

- FPL will suspend its current nuclear decommissioning accrual effective September 1, 2005, and at least through the minimum term of the Stipulation and Settlement. (Paragraph 11)

- New capital costs for expenditures recovered through the Environmental Cost Recovery Clause will be allocated, for the purpose of clause recovery, on a demand basis. (Paragraph 13)

- All post-September 11, 2001, incremental security costs will be recovered through the Capacity Cost Recovery Clause. (Paragraph 14)

- FPL will continue to operate without an authorized ROE range for the purpose of addressing earnings levels, but an ROE of 11.75% shall be used for all other regulatory purposes. (Paragraph 16)

- For any power plant that is approved through the Power Plant Siting Act and that achieves commercial operation within the term of the Stipulation and Settlement, the

> costs of which are not recovered fully through a clause or clauses, FPL's base rates will increase by the annualized base revenue requirement for the first 12 months of operation, reflecting the costs upon which the cumulative present value revenue requirements were or are predicated and pursuant to which a need determination was granted by the Commission. This base rate adjustment will be reflected on FPL's customer bills by increasing base charges and non-clause recoverable credits by an equal percentage and will apply to meter readings made on and after the commercial in-service date of the plant. (Paragraph 17)

Most of the terms of the Stipulation and Settlement appear to be self-explanatory. Still, we believe that several provisions merit comment or clarification so that as full an understanding of the parties' intent can be reflected in this Order before the Stipulation and Settlement is implemented. Based on the parties' discussions with our staff and discussions during our August 24 vote to approve the Stipulation and Settlement, we understand that the parties agree with the clarifications discussed below.

<u>Paragraph 2</u>

Under Paragraph 2, the parties agree that FPL will implement three new tariff offerings: an optional High Load Factor Time-of-Use rate with an adjustment to reflect a 65% load factor breakeven point by class; a Seasonal Demand Time-of-Use rate; and a General Service Constant Use rate. Further, the parties agree that FPL will eliminate the 10 kW exemption from its current rate schedules. We note that these changes are revenue neutral across FPL's demand-metered rate classes but are not revenue neutral within each such class.

Further, the parties agree that the inversion point on FPL's RS-1 (residential service) rate will be raised from 750 kWh to 1,000 kWh. We note that this change is revenue neutral within FPL's residential rate class.

The parties also agree that all gross receipts taxes will be shown as and collected through a separate gross receipts tax line item on bills. Thus, the portion of gross receipts taxes currently embedded in base rates will be removed and consolidated with the portion of gross receipts taxes currently shown separately.

<u>Paragraph 5</u>

Paragraph 5 describes and defines the revenue sharing plan agreed to by the parties. Part c of this paragraph states that the revenue sharing plan and the corresponding revenue sharing thresholds and revenue caps are intended to relate only to retail base rate revenues based on FPL's current structure and regulatory framework. Further, part c indicates that incremental revenues attributable to a business combination or acquisition involving FPL, its parent, or its affiliates will be excluded in determining retail base rate revenues for purposes of the revenue sharing plan. The parties clarified that in the event that a portion of FPL's system is sold or municipalized, appropriate adjustments would be made to account for the associated revenue reduction before application of FPL's annual average growth rate upon which the revenue sharing thresholds and revenue cap are calculated.

Paragraph 10

Under Paragraph 10, the parties agree that FPL will suspend its current base rate accrual of $20.3 million to its storm reserve account effective January 1, 2006. Further, the parties agree that a target for FPL's storm reserve account will be established in a separate proceeding and that funding the account to the target level will be achieved by either or both of two means: (1) a separate surcharge independent of and incremental to retail base rates; and (2) through the recently enacted provisions of Section 366.8260, Florida Statutes. FPL has committed to pursue continued funding of its storm reserve account within six months.

Paragraph 11

Pursuant to Paragraph 11, the parties agree that FPL will file a nuclear decommissioning study on or before December 12, 2005, but the study shall have no impact on FPL's base rates or charges or the terms of the Stipulation and Settlement. The parties clarified that the filing of this study is intended only for informational purposes and that no Commission action on the study is contemplated.

Paragraph 13

We note that Paragraph 13 reflects a change in practice with respect to the allocation of capital costs recovered through the Environmental Cost Recovery Clause (ECRC). These costs historically have been allocated to customer classes on an energy basis. Under the Stipulation and Settlement, the parties agree that new capital costs for environmental expenditures recovered through the ECRC will be allocated on a demand basis instead, consistent with the treatment of capital costs in a base rate cost of service study.

Paragraph 14

Currently, post-September 11, 2001, incremental security costs related only to power plant security are recovered through the Capacity Cost Recovery Clause (Capacity Clause). Pursuant to Paragraph 14, all post-September 11, 2001, incremental security costs – both power plant and non-plant security costs – will be recovered through the Capacity Clause.

Paragraph 17

The parties clarified that in the event the actual capital cost of a generation project subject to Paragraph 17 is lower than the projected cost, the difference will be reflected as a one-time credit through the Capacity Clause.

Other Matters

Pursuant to a stipulation approved in Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, FPL currently recovers incremental hedging costs through the Fuel Cost Recovery Clause (Fuel Clause). In its petition for a rate increase, FPL proposed to recover these costs through base rates instead. The Stipulation and Settlement is silent on how incremental hedging costs will be recovered. The parties clarified that they intended for recovery of these costs to continue through the Fuel Clause during the term of the Stipulation and Settlement. Because the Stipulation is silent in this regard, the parties indicated that they would take action to memorialize their intent in this year's Fuel Clause proceedings.

The parties also clarified their intent that, upon approval of this Stipulation and Settlement, Docket No. 050494-EI should be closed. Docket No. 050494-EI was assigned to a joint petition for a decrease in FPL's base rates and charges filed July 19, 2005, by several of the intervenors in this docket.

III. FINDINGS

Upon review and consideration, we find that the Stipulation and Settlement provides a reasonable resolution of the issues in this proceeding with respect to FPL's rates and charges and its depreciation rates and capital recovery schedules. The Stipulation and Settlement appears to provide FPL's customers with a degree of stability and predictability with respect to their electricity rates while allowing FPL to maintain the financial strength to make investments necessary to provide customers with safe and reliable power. Further, the Stipulation and Settlement extends through 2009 a revenue sharing plan which, since its inception in 1999, has resulted in refunds to customers of over $225 million to date. In addition, we recognize that the Stipulation and Settlement reflects the agreement of a broad range of interests: FPL, OPC, the Attorney General, and residential, commercial, industrial, and governmental customers of FPL.

In conclusion, we find that the Stipulation and Settlement establishes rates that are fair, just, and reasonable and that approval of the Stipulation and Settlement is in the public interest. Therefore, we approve the Stipulation and Settlement. As with any settlement we approve, nothing in our approval of this Stipulation and Settlement diminishes this Commission's ongoing authority and obligation to ensure fair, just, and reasonable rates. Nonetheless, this Commission has a long history of encouraging settlements, giving great weight and deference to settlements, and enforcing them in the spirit in which they were reached by the parties.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the Stipulation and Settlement filed August 22, 2005, which is attached hereto as Attachment A and incorporated herein by reference, is approved. It is further

ORDERED that FPL shall file, for administrative approval, revised tariff sheets to reflect the terms of the Stipulation and Settlement. It is further

ORDERED that Docket Nos. 050045-EI, 050188-EI, and 050494-EI shall be closed.

By ORDER of the Florida Public Service Commission this 14th day of September, 2005.

BLANCA S. BAYÓ, Director
Division of the Commission Clerk
and Administrative Services

By: Kay Flynn
Kay Flynn, Chief
Bureau of Records

(SEAL)

WCK

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: (1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or (2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of the Commission Clerk and Administrative Services and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

ATTACHMENT A

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company.	Docket No. 050045-EI
In re: 2005 comprehensive depreciation study by Florida Power & Light Company.	Docket No. 050188-EI

STIPULATION AND SETTLEMENT

WHEREAS, pursuant to its petition filed March 22, 2005, Florida Power & Light Company (FPL) has petitioned the Florida Public Service Commission (FPSC or Commission) for an increase in base rates and other related relief;

WHEREAS, the Office of the Attorney General (AG), the Office of Public Counsel (OPC), The Florida Industrial Power Users Group (FIPUG), AARP, Florida Retail Federation (FRF), the Commercial Group (CG), the Federal Executive Agencies (FEA), and South Florida Hospital and Healthcare Association (SFHHA) have intervened, and have signed this Stipulation and Settlement (unless the context clearly requires otherwise, the term Party or Parties means a signatory to this Stipulation and Settlement);

WHEREAS, FPL and the Parties to this Stipulation and Settlement recognize that this is a period of unprecedented world energy prices and that this Stipulation and Settlement will mitigate the impact of high energy prices;

WHEREAS, FPL has provided the minimum filing requirements (MFRs) as required by the FPSC and such MFRs have been thoroughly reviewed by the FPSC Staff and the Parties to this proceeding;

ATTACHMENT A

WHEREAS, FPL has filed comprehensive testimony in support of and detailing its MFRs;

WHEREAS, on March 16, 2005, FPL filed comprehensive depreciation studies in accordance with FPSC Rule 25-6.0436(8)(a), Florida Administrative Code;

WHEREAS, the parties in this proceeding have conducted extensive discovery on the MFRs, depreciation studies, and FPL's testimony;

WHEREAS, the discovery conducted has included the production and opportunity to inspect more than 315,000 pages of information regarding FPL's costs and operations;

WHEREAS, the Parties to this Stipulation and Settlement have undertaken to resolve the issues raised in these proceedings so as to maintain a degree of stability to FPL's base rates and charges, and to provide incentives to FPL to continue to promote efficiency through the term of this Stipulation and Settlement;

WHEREAS, FPL is currently operating under a stipulation and settlement agreement agreed to by OPC and other parties, and approved by the FPSC by Order PSC-02-0501-AS-EI, issued April 11, 2002, in Docket Nos. 001148-EI and 020001-EI (2002 Agreement);

WHEREAS, previous to the 2002 Agreement, FPL operated under a stipulation and settlement agreement approved by the FPSC in Order No. PSC 99-0519-AS-EI (1999 Agreement);

WHEREAS, the 1999 and 2002 Agreements, combined, provided for a reduction of $600 million in FPL's base rates, and include revenue sharing plans that have resulted in refunds to customers to date in excess of $225 million;

WHEREAS, the 1999 and 2002 Agreements and revenue sharing plans have provided significant benefits to customers, resulting in approximately $4 billion in total savings to FPL's customers through the end of 2005;

WHEREAS, during 2005 FPL has added two new power plants in Martin and Manatee Counties at installed costs totaling approximately $887 million without increasing base rates;

WHEREAS, FPL must make substantial investments in the construction of new electric generation and other infrastructure for the foreseeable future in order to continue to provide safe and reliable power to meet the growing needs of retail customers in the state of Florida; and

WHEREAS, an extension of the revenue sharing plan and preservation of the benefits for customers of the $600 million reduction in base rates provided for in the 1999 and 2002 Agreements during the period in which this Stipulation and Settlement is in effect, and other provisions as set forth herein, including the provision for the incremental base rate recovery of costs associated with the addition of electric generation, will further be beneficial to retail customers;

NOW THEREFORE, in consideration of the foregoing and the covenants contained herein, the Parties hereby stipulate and agree:

1. Upon approval and final order of the FPSC, this Stipulation and Settlement will become effective on January 1, 2006 (the "Implementation Date"), and shall continue through December 31, 2009 (the "Minimum Term"), and thereafter shall remain in effect until terminated on the date that new base rates become effective pursuant to order of the FPSC following a formal administrative hearing held either on the FPSC's own motion or on request made by any of the Parties to this Stipulation and Settlement in accordance with Chapter 366, Florida Statutes.

ATTACHMENT A

2. FPL's retail base rates and base rate structure shall remain unchanged, except as otherwise permitted in this Stipulation and Settlement. The following tariff changes shall be approved and implemented:

a. (i) As reflected in FPL's MFR E-14, institution of the optional High Load Factor Time-of-Use rate with an adjustment to reflect a 65% load factor breakeven point by rate class, the Seasonal Demand Time-of-Use rate, and the General Service Constant Use Rate;

(ii) Elimination of the 10 kW exemption from rates.

(iii) The combined adjustments to implement (i) and (ii) above shall be made on a revenue neutral basis with reference to the 2006 forecast reflected in MFR E-13(c) at present base rates.

b. Raising the inversion point on the RS-1 rate from 750 kWh to 1,000 kWh, on a revenue neutral basis with reference to the 2006 forecast reflected in MFR E-13(c) at present base rates.

c. Consolidation and collection of all gross receipts taxes, including existing gross receipts taxes embedded in base rates, through the separate gross receipts tax line item on bills, on a revenue neutral basis with reference to the 2006 forecast reflected in MFR E-13(c) at present base rates.

d. At any time during the term of the Stipulation and Settlement and subject to Commission approval, any new or revised tariff provisions or rate schedules requested by FPL, provided that such tariff request does not increase any existing base rate component of a tariff or rate schedule during the term of the

ATTACHMENT A

Stipulation and Settlement unless the application of such new or revised tariff or rate schedule is optional to the utility's customers.

3. Except as provided in Section 1, no Party to this Stipulation and Settlement will request, support, or seek to impose a change in the application of any provision hereof. AG, OPC, FIPUG, AARP, FRF, FEA, CG, and SFHHA will neither seek nor support any reduction in FPL's base rates and charges, including interim rate decreases, to take effect prior to the end of the Minimum Term of this Stipulation and Settlement unless a reduction request is initiated by FPL. FPL will not petition for an increase in its base rates and charges, including interim rate increases, to take effect for meter readings before the end of the Minimum Term except as provided for in Section 6. During the term of this Stipulation and Settlement, except as otherwise provided for in this Stipulation and Settlement, or except for unforeseen extraordinary costs imposed by government agencies relating to safety or matters of national security, FPL will not petition for any new surcharges, on an interim or permanent basis, to recover costs that are of a type that traditionally and historically would be, or are presently, recovered through base rates.

4. During the term of this Stipulation and Settlement, revenues which are above the levels stated herein below in Section 5 will be shared between FPL and its retail electric utility customers -- it being expressly understood and agreed that the mechanism for earnings sharing herein established is not intended to be a vehicle for "rate case" type inquiry concerning expenses, investment, and financial results of operations.

5. Commencing on the Implementation Date and for the calendar years 2006, 2007, 2008 and 2009, and continuing thereafter until terminated, FPL will be under a Revenue Sharing Incentive Plan as set forth below. For purposes of this Revenue Sharing Incentive Plan, the following retail base rate revenue threshold amounts are established:

a. Sharing Threshold - Retail base rate revenues between the sharing threshold amount and the retail base rate revenue cap as defined in Section 5(b) below will be divided into two shares on a 1/3, 2/3 basis. FPL's shareholders shall receive the 1/3 share. The 2/3 share will be refunded to retail customers. The sharing threshold for 2006 will be established by using the 2005 sharing threshold of $3,880 million in retail base rate revenues, increased by the average annual growth rate in retail kWh sales for the ten year period ending December 31, 2005. For each succeeding calendar year or portion thereof during which the Stipulation and Settlement is in effect, the succeeding calendar year retail base rate revenue sharing threshold amounts shall be established by increasing the prior year's threshold by the sum of the following two amounts: (i) the average annual growth rate in retail kWh sales for the ten calendar year period ending December 31 of the preceding year multiplied by the prior year's retail base rate revenue sharing threshold and (ii) the amount of any incremental GBRA revenues in that year. The GBRA is described in Section 17.

b. Revenue Cap - Retail base rate revenues above the retail base rate revenue cap will be refunded to retail customers on an annual basis. The retail base rate revenue cap for 2006 will be established by using the 2005 cap of $4,040 million in retail base rate revenues, increased by the average annual growth rate in retail kWh sales for the ten calendar year period ending December 31, 2005. For each succeeding calendar year or portion thereof during which the Stipulation and Settlement is in effect, the succeeding calendar year retail base rate revenue cap amounts shall be established by increasing the prior year's cap by the sum of the following two amounts: (i) the average annual growth rate in retail kWh sales for the ten calendar year period ending December 31 of the preceding year multiplied by the prior year's retail base rate revenue cap amount and (ii) the amount of any incremental GBRA revenues in that year.

c. Revenue exclusions - The Revenue Sharing Incentive Plan and the corresponding revenue sharing thresholds and revenue caps are intended to relate only to retail base rate revenues of FPL based on its current structure and regulatory framework. Thus, for example, incremental revenues attributable to a business combination or acquisition involving FPL, its parent, or its affiliates, whether inside or outside the state of Florida, or revenues from any clause, surcharge or other recovery mechanism other than retail base rates, shall be excluded in determining retail base rate revenues for purposes of revenue sharing under this Stipulation and Settlement.

d. Refund mechanism - Refunds will be paid to customers as described in Section 7.

e. Calculation of sharing threshold and revenue cap for partial calendar years – In the event that this Stipulation and Settlement is terminated other than at the end of a calendar year, the sharing threshold and revenue cap for the partial calendar year shall be determined at the end of that calendar year by (i) dividing the retail kWh sales during the partial calendar year by the retail kWh for the full calendar year, and (ii) applying the resulting fraction to the sharing threshold and revenue cap for the full calendar year that would have been calculated as set forth in Sections 5(a) and 5(b) above.

f. Calculation of annual average growth rate - For purposes of this Section 5, the average annual growth rate shall be calculated by summing the percentage change in retail kWh sales for each year in the relevant ten year period and dividing by 10.

6. If FPL's retail base rate earnings fall below a 10% ROE as reported on an FPSC adjusted or pro-forma basis on an FPL monthly earnings surveillance report during the term of this Stipulation and Settlement, FPL may petition the FPSC to amend its base rates notwithstanding the provisions of Section 3, either as a general rate proceeding or as a limited proceeding under Section 366.076, Florida Statutes. Parties to this Stipulation and Settlement are not precluded from participating in such a proceeding, and, in the event that FPL petitions to initiate a limited proceeding under this Section 6, any Party may petition to initiate any proceeding otherwise permitted by Florida law. This Stipulation and Settlement shall terminate upon the effective date of any Final Order issued in such proceeding that changes FPL's base rates. This paragraph shall not be construed to bar or limit FPL from any recovery of costs otherwise contemplated by this Stipulation and Settlement.

7. All revenue-sharing refunds will be paid with interest at the 30-day commercial paper rate to retail customers of record during the last three months of each applicable refund period based on their proportionate share of base rate revenues for the refund period. For purposes of calculating interest only, it will be assumed that revenues to be refunded were collected evenly throughout the preceding refund period. All refunds with interest will be in the form of a credit on the customers' bills beginning with the first day of the first billing cycle of the second month after the end of the applicable refund period (or, in the case of a partial calendar year refund, after the end of that calendar year). Refunds to former customers will be completed as expeditiously as reasonably possible.

8. Starting with the effective date of this Stipulation and Settlement, FPL may, at its option, amortize up to $125,000,000 annually as a credit to depreciation expense and a debit to the bottom line depreciation reserve over the term of this Stipulation and Settlement. Any such

reserve amount will be applied first to reduce any reserve excesses by account, as determined in FPL's depreciation studies filed after the term of this Stipulation and Settlement, and thereafter will result in reserve deficiencies. Any such reserve deficiencies will be allocated to individual reserve balances based on the ratio of the net book value of each plant account to total net book value of all plant. The amounts allocated to the reserves will be included in the remaining life depreciation rate and recovered over the remaining lives of the various assets. Additionally, depreciation rates and/or capital recovery schedules shall be established pursuant to the comprehensive depreciation studies as filed March 16, 2005 and will not be changed for the term of this Stipulation and Settlement.

9. FPL will be permitted clause recovery of prudently incurred incremental costs associated with the establishment of a Regional *Transmission* Organization or any other costs arising from an order of the FPSC or the Federal Energy Regulatory Commission addressing any alternative configuration or structure to address independent transmission system governance or operation. Any Party to this Stipulation and Settlement may participate in any proceeding relating to the recovery of costs contemplated in this section for the purpose of challenging the reasonableness and prudence of such costs, but not for the purpose of challenging FPL's right to clause recovery of such costs.

10. No Party to this Stipulation and Settlement shall appeal the FPSC's Final Order in Docket No. 041291-EI. Further, Parties agree to the following provisions relative to the target level and funding of Account No. 228.1 and recovery of any deficits in such Account:

a. The target level for Account No. 228.1 shall be as established by the Commission, whether on its own motion, upon petition by FPL, or in conjunction with a proceeding held in accordance with *Section 366.8260,* Florida Statutes. FPL will be permitted to recover prudently incurred costs associated with events covered by Account No. 228.1 and replenish Account No. 228.1 to a target level through charges to customers, that are approved by the Commission, that are independent of and incremental to base rates and without the application of any form of earnings test or measure. The fact that insufficient funds have been accumulated in Account No. 228.1 to cover costs associated with events covered by that Account shall not be evidence of imprudence or the basis of a disallowance. Replenishment of Account No. 228.1 to a target level approved by the Commission and/or the recovery of any costs incurred in excess of funds accumulated in Account No. 228.1 and insurance shall be accomplished through Section 366.8260, Florida Statutes, and/or through a separate surcharge that is independent of and incremental to retail base rates, as approved by the Commission. Parties to this Stipulation and Settlement are not precluded from participating in such a proceeding, nor precluded from challenging the amount of such target level or whether recovery should be accomplished either through Section 366.8260, Florida Statutes or through a separate surcharge.

b. The current base rate accrual to Account No. 228.1 of $20.3 million is suspended effective January 1, 2006.

c. No revenues contemplated by this Section 10 shall be included in the computation of retail base rate revenues for purposes of revenue sharing under this Stipulation and Settlement.

ATTACHMENT A

11. The current decommissioning accrual of $78,516,937 (jurisdictional) approved in Order No. PSC-02-0055-PAA-EI shall be suspended effective September 1, 2005 and shall remain suspended through the Minimum Term and, at the Company's option, for any additional period during which this Stipulation and Settlement remains in effect. FPL's decommissioning study to be filed on or before December 31, 2005 shall have no impact on FPL's base rates, charges, or the terms of this Stipulation and Settlement.

12. The portion of St. Johns River Power Park ("SJRPP") capacity costs and certain capacity revenues that are currently embedded in base rates shall continue to be recovered through base rates in the current manner as contemplated by Order No. PSC-92-1334-FOF-EI.

13. New capital costs for environmental expenditures recovered through the Environmental Cost Recovery Clause will be allocated, for the purpose of clause recovery, consistent with FPL's current cost of service methodology.

14. Post-September 11, 2001 incremental security costs shall remain in and be recovered through the Capacity Clause.

15. For surveillance reporting requirements and all regulatory purposes, FPL's ROE will be calculated based upon an adjusted equity ratio as follows. FPL's adjusted equity ratio will be capped at 55.83% as included in FPL's projected 1998 Rate of Return Report for surveillance purposes. The adjusted equity ratio equals common equity divided by the sum of common equity, preferred equity, debt and off-balance sheet obligations. The amount used for off-balance sheet obligations will be calculated per the Standard & Poor's methodology.

16. Effective on the Implementation Date, FPL will continue to operate without an authorized Return on Equity (ROE) range for the purpose of addressing earnings levels, and the

revenue sharing mechanism herein described will be the appropriate and exclusive mechanism to address earnings levels, but an ROE of 11.75% shall be used for all other regulatory purposes.

17. For any power plant that is approved pursuant to the Florida Power Plant Siting Act (PPSA) and achieves commercial operation within the term of this Stipulation and Settlement, the costs of which are not recovered fully through a clause or clauses, FPL's base rates will be increased by the annualized base revenue requirement for the first 12 months of operation, reflecting the costs upon which the cumulative present value revenue requirements (CPVRR) were or are predicated, and pursuant to which a need determination was granted by the FPSC, such adjustment to be reflected on FPL's customer bills by increasing base charges, and non-clause recoverable credits, by an equal percentage. FPL will begin applying the incremental base rate charges required by this Stipulation and Settlement to meter readings made on and after the commercial in service date of any such power plant. Such adjustment shall be referred to as a Generation Base Rate Adjustment (GBRA). The GBRA will be calculated using an 11.75% ROE and the capital structure as per Section 15 above. FPL will calculate and submit for Commission confirmation the amount of the GBRA using the Capacity Clause projection filing for the year that the plant is to go into service. In the event that the actual capital costs of generation projects are lower than were or are projected in the need determination proceeding, the difference will be flowed back via a true-up to the Capacity Clause. In the event that actual capital costs for such power plant are higher than were projected in the need determination proceeding, FPL at its option may initiate a limited proceeding per Section 366.076, Florida Statutes, limited to the issue of whether FPL has met the requirements of Rule 25-22.082(15), Florida Administrative Code. If the Commission finds that FPL has met the requirements of Rule 25-22.082(15), FPL shall increase the GBRA by the corresponding incremental revenue

requirement due to such additional capital costs. However, FPL's election not to seek such an increase in the GBRA shall not preclude FPL from booking any incremental costs for surveillance reporting and all regulatory purposes subject only to a finding of imprudence or disallowance by the Commission. Upon termination of the Stipulation and Settlement, FPL's base rate levels, including the effects of any GBRA, shall continue in effect until next reset by the Commission. Any Party to this Stipulation and Settlement may participate in any such limited proceeding for the purpose of challenging whether FPL has met the requirements of Rule 25-22.082(15). A GBRA shall be implemented upon commercial operation of Turkey Point Unit 5, currently projected to occur in mid-2007, by increasing base rates by the estimated annual revenue requirement exclusive of fuel of the costs upon which the CPVRR for Turkey Point Unit 5 were predicated, and pursuant to which a need determination was granted by the FPSC in Order No. PSC-04-0609-FOF-EI, such adjustment to be reflected on FPL's customer bills by increasing base charges and non-clause recoverable credits, by an equal percentage. FPL will begin applying the incremental base rate charges required by this Stipulation and Settlement to meter readings made on and after the commercial in service date of Turkey Point Unit 5.

18. This Stipulation and Settlement is contingent on approval in its entirety by the FPSC. This Stipulation and Settlement will resolve all matters in these Dockets pursuant to and in accordance with Section 120.57(4), Florida Statutes. This Docket will be closed effective on the date the FPSC Order approving this Stipulation and Settlement is final.

19. All Parties to this Stipulation and Settlement agree to endorse and support the Stipulation and Settlement before the FPSC and any other administrative or judicial tribunal, and in any other forum.

20. This Stipulation and Settlement dated as of August 22, 2005 may be executed in counterpart originals, and a facsimile of an original signature shall be deemed an original.

In Witness Whereof, the Parties evidence their acceptance and agreement with the provisions of this Stipulation and Settlement by their signature.

Florida Power & Light Company
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ATTACHMENT A

The Commercial Group

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Florida Retail Federation

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Federal Executive Agencies

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By: Craig Paulson
Major Craig Paulson, Esq.

Common Cause, Florida
+ individual customers

EXHIBIT___(LK-4)

FPL GROUP.

FPL.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended **March 31, 2009**

Commission File Number	Exact name of registrants as specified in their charters, address of principal executive offices and registrants' telephone number	IRS Employer Identification Number
1-8841	**FPL GROUP, INC.**	59-2449419
2-27612	**FLORIDA POWER & LIGHT COMPANY** 700 Universe Boulevard Juno Beach, Florida 33408 (561) 694-4000	59-0247775

State or other jurisdiction of incorporation or organization: Florida

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) have been subject to such filing requirements for the past 90 days.

FPL Group, Inc. Yes ☑ No ☐ Florida Power & Light Company Yes ☑ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).

FPL Group, Inc. Yes ☐ No ☐ Florida Power & Light Company Yes ☐ No ☐

Indicate by check mark whether the registrants are a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Securities Exchange Act of 1934.

FPL Group, Inc.	Large Accelerated Filer ☑	Accelerated Filer ☐	Non-Accelerated Filer ☐	Smaller Reporting Company ☐
Florida Power & Light Company	Large Accelerated Filer ☐	Accelerated Filer ☐	Non-Accelerated Filer ☑	Smaller Reporting Company ☐

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ☐ No ☑

The number of shares outstanding of FPL Group, Inc. common stock, as of the latest practicable date: Common Stock, $0.01 par value, outstanding at March 31, 2009: 410,792,950 shares.

As of March 31, 2009, there were issued and outstanding 1,000 shares of Florida Power & Light Company common stock, without par value, all of which were held, beneficially and of record, by FPL Group, Inc.

This combined Form 10-Q represents separate filings by FPL Group, Inc. and Florida Power & Light Company. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Florida Power & Light Company makes no representations as to the information relating to FPL Group, Inc.'s other operations.

Florida Power & Light Company meets the conditions set forth under General Instruction H.(1)(a) and (b) of Form 10-Q and is therefore filing this Form with the reduced disclosure format

FLORIDA POWER & LIGHT COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(millions)
(unaudited)

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
OPERATING REVENUES	$ 2,573	$ 2,534
OPERATING EXPENSES		
Fuel, purchased power and interchange	1,469	1,457
Other operations and maintenance	340	378
Storm cost amortization	19	11
Depreciation and amortization	232	196
Taxes other than income taxes	251	248
Total operating expenses	2,311	2,290
OPERATING INCOME	262	244
OTHER INCOME (DEDUCTIONS)		
Interest expense	(77)	(86)
Allowance for equity funds used during construction	15	5
Interest income	-	4
Other – net	(2)	(3)
Total other deductions – net	(64)	(80)
INCOME BEFORE INCOME TAXES	198	164
INCOME TAXES	71	56
NET INCOME	$ 127	$ 108

This report should be read in conjunction with the Notes herein and the Notes to Consolidated Financial Statements appearing in the 2008 Form 10-K for FPL Group and FPL.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

This discussion should be read in conjunction with the Notes contained herein and Management's Discussion and Analysis of Financial Condition and Results of Operations (Management's Discussion) appearing in the 2008 Form 10-K for FPL Group and FPL. The results of operations for an interim period generally will not give a true indication of results for the year. In the following discussion, all comparisons are with the corresponding items in the prior year period.

Results of Operations

FPL Group and NextEra Energy Resources segregate into two categories unrealized mark-to-market gains and losses on energy derivative transactions which are used to manage commodity price risk. The first category, referred to as trading activities, represents the net unrealized effect of actively traded positions entered into to take advantage of market price movements and to optimize the value of generation assets and related contracts. The second category, referred to as non-qualifying hedges, represents the net unrealized effect of derivative transactions entered into as economic hedges but which do not qualify for hedge accounting and the ineffective portion of transactions accounted for as cash flow hedges. At FPL, substantially all changes in the fair value of energy derivative transactions are deferred as a regulatory asset or liability until the contracts are settled, and, upon settlement, any gains or losses are passed through the fuel clause or the capacity clause.

FPL Group's management uses earnings excluding certain items (adjusted earnings) internally for financial planning, for analysis of performance, for reporting of results to the Board of Directors and as inputs in determining whether performance targets are met for performance-based compensation under FPL Group's employee incentive compensation plans. FPL Group also uses adjusted earnings when communicating its earnings outlook to investors. Adjusted earnings exclude the unrealized mark-to-market effect of non-qualifying hedges and other than temporary impairment (OTTI) losses on securities held in NextEra Energy Resources' nuclear decommissioning funds, net of the reversal of previously recognized OTTI losses on securities sold and losses on securities where price recovery was deemed unlikely (collectively, OTTI reversals). FPL Group's management believes adjusted earnings provide a more meaningful representation of the company's fundamental earnings power. Although the excluded amounts are properly included in the determination of net income in accordance with generally accepted accounting principles, management believes that the amount and/or nature of such items make period to period comparisons of operations difficult and potentially confusing. Adjusted earnings does not represent a substitute for net income, as prepared in accordance with generally accepted accounting principles.

In March 2009, FPL, certain subsidiaries of NextEra Energy Resources and certain nuclear plant joint owners signed a settlement agreement with the U.S. Government (settlement agreement) agreeing to dismiss with prejudice lawsuits filed against the U.S. Government seeking damages caused by the U.S. Department of Energy's failure to dispose of spent nuclear fuel from FPL's and NextEra Energy Resources' nuclear plants. In connection with the settlement agreement, FPL Group established an approximately $153 million ($100 million for FPL) receivable from the U.S. Government and a liability to nuclear plant joint owners of $22 million ($5 million for FPL), which are included with other receivables and other current liabilities, respectively, in the condensed consolidated balance sheets at March 31, 2009. In addition, FPL Group reduced its March 31, 2009 property, plant and equipment balances by $107 million ($83 million for FPL) and, for the three months ended March 31, 2009, reduced operating expenses by $15 million ($12 million for FPL) and increased operating revenues by $9 million. The payments due from the U.S. Government under the settlement agreement increased FPL Group's net income for the three months ended March 31, 2009 by approximately $16 million ($9 million for FPL). A substantial portion of the amount due from the U.S. Government is expected during the second quarter of 2009. FPL and NextEra Energy Resources will continue to pay fees to the U.S. Government's nuclear waste fund.

Summary – Presented below is a summary of net income (loss) by reportable segment (see Note 10):

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
	(millions)	
FPL	$ 127	$ 108
NextEra Energy Resources	252	164
Corporate and Other	(15)	(23)
FPL Group Consolidated	$ 364	$ 249

The increase in FPL's results for the three months ended March 31, 2009 reflects the settlement agreement, lower operations and maintenance (O&M) expenses and a higher equity component of AFUDC (AFUDC – equity) partly offset by lower retail customer usage.

NextEra Energy Resources' results for the three months ended March 31, 2009 reflect additional earnings from new investments, the foreign, state and convertible ITCs tax benefits (see Note 4), as well as the absence of an unplanned outage in 2008 at the Seabrook nuclear facility and the settlement agreement. These additional earnings were partially offset by lower results in the remainder of the existing portfolio primarily due to Electric Reliability Council of Texas (ERCOT) market conditions, a refueling outage at the Duane Arnold nuclear site and lower wind generation primarily due to a particularly strong wind resource in the prior quarter. In addition, interest expense and administrative and general expenses were higher to support growth of the business. FPL Group's and NextEra Energy Resources' net income for the three months ended March 31, 2009 reflects net unrealized after-tax gains from non-qualifying hedges of $30 million while in the prior period net income reflects net unrealized after-tax losses from such hedges of $52 million. The change in unrealized mark-to-market activity is primarily attributable to changes in forward power and natural gas prices, as well as the reversal of previously recognized unrealized mark-to-market gains/losses as the underlying transactions are realized. As a general rule, a gain (loss) in the non-qualifying hedge category is offset by decreases (increases) in the fair value of related physical asset positions in the portfolio or contracts, which are not marked to market under generally accepted accounting principles. For the three months ended March 31, 2009 and 2008, NextEra Energy Resources recorded $31 million and $4 million, respectively, of after-tax OTTI losses on securities held in NextEra Energy Resources' nuclear decommissioning funds. For the three months ended March 31, 2009, NextEra Energy Resources had approximately $1 million of after-tax OTTI reversals; there were no such OTTI reversals for the three months ended March 31, 2008.

The improvement in results for Corporate and Other in 2009 is primarily due to additional interest income.

FPL – FPL's net income for the three months ended March 31, 2009 and 2008 was $127 million and $108 million, respectively, an increase of $19 million. The increase reflects the settlement agreement, lower O&M expenses and higher AFUDC – equity partly offset by lower retail customer usage.

In March 2009, FPL filed a petition with the FPSC requesting, among other things, a permanent increase in base rates and charges effective January 2010 and an additional permanent base rate increase effective January 2011. To address the addition of FPL's West County Energy Center Unit No. 3 and any subsequent power plant additions, FPL is also requesting FPSC approval to continue the GBRA mechanism previously approved by the FPSC as part of the stipulation and settlement agreement regarding FPL's 2005 base rate case. If approved, the requested permanent base rate increases would increase annual retail base revenues year-over-year by approximately $1 billion in 2010 and an additional $250 million in 2011. FPL's requested increases are based on a regulatory return on common equity of 12.5% and exclude amounts associated with the proposed extension of the GBRA mechanism and certain proposed cost recovery clause adjustments. Hearings on this base rate proceeding are expected during the third quarter of 2009 and a final decision is expected by the end of 2009. The final decision may approve rates and other terms that are different from those that FPL has requested. The 2005 rate agreement and its provisions will terminate on the date new retail base rates become effective pursuant to an FPSC order. FPL expects that retail base revenues will increase approximately $65 million in 2009 when retail base rates are changed pursuant to the GBRA mechanism to reflect the placement in service of West County Energy Center Unit Nos. 1 and 2, which is expected to occur by the third quarter of 2009 and fourth quarter of 2009, respectively.

FPL's operating revenues consisted of the following:

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
	(millions)	
Retail base	$ 794	$ 822
Fuel cost recovery	1,325	1,331
Other cost recovery clauses and pass-through costs	404	333
Other, primarily pole attachment rentals, transmission and wholesale sales and customer-related fees	50	48
Total	$ 2,573	$ 2,534

For the three months ended March 31, 2009, a decrease in the average number of customers of 0.4% decreased retail base revenues by approximately $3 million while a 4.4% decrease in usage per retail customer, primarily reflecting factors other than weather conditions, decreased retail base revenues by approximately $25 million. The decline FPL experienced in retail customer growth in the latter half of 2007 and throughout 2008 as well as a decline in non-weather related retail customer usage, which FPL believes is reflective of the economic slowdown and housing crisis that has affected the country and the state of Florida, has continued into 2009. FPL is unable to predict if growth in customers and non-weather related customer usage will return to previous trends. The decline in retail customer usage for the three months ended March 31, 2009 also reflects one less day of sales in 2009, as 2008 was a leap year.

Revenues from fuel and other cost recovery clauses and pass-through costs, such as franchise fees, revenue taxes and storm-related surcharges do not significantly affect net income; however, underrecovery or overrecovery of such costs can significantly affect FPL Group's and FPL's operating cash flows. Fluctuations in fuel cost recovery revenues are primarily driven by changes in fuel and energy charges which are included in fuel, purchased power and interchange expense in the condensed consolidated statements of income, as well as by changes in energy sales. Fluctuations in revenues from other cost recovery clauses and pass-through costs are primarily driven by changes in storm-related surcharges, capacity charges, franchise fee costs, the impact of changes in O&M and depreciation expenses on the underlying cost recovery clause, as well as changes in energy sales. Capacity charges and franchise fee costs are included in fuel, purchased power and interchange and taxes other than income taxes, respectively, in the condensed consolidated statements of income.

FPL uses a risk management fuel procurement program which was approved by the FPSC at the program's inception. The FPSC reviews the program activities and results for prudence on an annual basis as part of its annual review of fuel costs. The program is intended to manage fuel price volatility by locking in fuel prices for a portion of FPL's fuel requirements; any resulting gains or losses are passed through the fuel clause. The current regulatory asset for the change in fair value of derivative instruments used in the fuel procurement program amounted to approximately $1,309 million and $1,109 million at March 31, 2009 and December 31, 2008, respectively. The decrease in fuel revenues for the three months ended March 31, 2009 reflects approximately $58 million attributable to lower energy sales partly offset by approximately $52 million related to a higher average fuel factor. The increase in revenues from other cost recovery clauses and pass-through costs is primarily due to additional revenues associated with the nuclear cost recovery rule.

The major components of FPL's fuel, purchased power and interchange expense are as follows:

	Three Months Ended March 31,	
	2009	2008
	(millions)	
Fuel and energy charges during the period	$ 1,083	$ 1,236
Net collection of previously deferred retail fuel costs	254	104
Other, primarily capacity charges net of any capacity deferral	132	117
Total	$ 1,469	$ 1,457

The decrease in fuel and energy charges for the three months ended March 31, 2009 reflects lower fuel and energy prices of approximately $104 million and $49 million attributable to lower energy sales. At March 31, 2009, approximately $1 million of retail fuel costs were deferred pending collection from retail customers in a subsequent period. The decrease from December 31, 2008 to March 31, 2009 in deferred clause and franchise expenses and the increase in deferred clause and franchise revenues (current and noncurrent, collectively) on FPL Group's and FPL's condensed consolidated balance sheets totaled approximately $266 million and positively affected FPL Group's and FPL's cash flows from operating activities for the three months ended March 31, 2009.

FPL's O&M expenses decreased $38 million for the three months ended March 31, 2009 reflecting lower nuclear, fossil generation and distribution costs of approximately $20 million, $12 million and $12 million, respectively. The decline in nuclear costs reflects a reimbursement of costs expected under the terms of the settlement agreement, as well as lower costs related to plant improvement initiatives and refueling and maintenance outages. The decline in fossil generation costs is primarily due to differences in the timing of plant overhauls which are expected to occur later this year. The decline in distribution costs reflects lower support costs and the timing of work activities. Other changes in O&M expenses were primarily driven by pass-through costs which did not significantly affect net income. Management expects O&M expenses in 2009 to exceed the 2008 level, primarily due to the absence of an environmental insurance policy termination which occurred in the fourth quarter of 2008, as well as higher expected nuclear, fossil generation, transmission, customer service, information management and other support costs and employee benefit costs.

Depreciation and amortization expense for the three months ended March 31, 2009 increased $38 million, reflecting the amortization of approximately $32 million of pre-construction costs associated with FPL's planned nuclear units recovered under the nuclear cost recovery rule and higher depreciation on transmission and distribution facilities (collectively, approximately $6 million) offset by a reduction in depreciation due to the settlement agreement.

The decline in interest expense for the three months ended March 31, 2009 is primarily due to a decline in average interest rates of approximately 62 basis points, partly offset by higher average debt balances. The decline in interest expense also reflects a higher debt component of AFUDC. The increase in AFUDC – equity for the three months ended March 31, 2009 is primarily attributable to additional AFUDC – equity on three natural gas-fired combined-cycle units of approximately 1,220 mw each at FPL's West County Energy Center in western Palm Beach County, Florida.

FPL is currently constructing the three natural gas-fired combined-cycle units at its West County Energy Center, which units are expected to be placed in service by the third quarter of 2009, fourth quarter of 2009 and mid-2011, respectively. In addition, FPL is in the process of adding approximately 400 mw of baseload capacity at its existing nuclear units at St. Lucie and Turkey Point, which additional capacity is projected to be placed in service by the end of 2012. In 2008, the FPSC approved FPL's plan to modernize its Cape Canaveral and Riviera power plants to high-efficiency natural gas-fired units. Each modernized plant is expected to provide approximately 1,200 mw of capacity and be placed in service by 2013 and 2014, respectively. Siting Board approval is pending and a decision is expected in early 2010. In April 2009, FPL filed a need petition with the FPSC for an approximately 300-mile underground natural gas pipeline in Florida, which is projected to be in service in 2014. If approved, the pipeline would supply natural gas to the Cape Canaveral and Riviera power plants once they are modernized. An FPSC decision is expected in July 2009. The pipeline requires additional approvals from, among others, the Siting Board.

In 2008, the FPSC approved FPL's need petition for two additional nuclear units at its Turkey Point site with projected in-service dates between 2018 and 2020, which units are expected in the aggregate to add between 2,200 mw and 3,040 mw of baseload capacity. Additional approvals from other regulatory agencies will be required later in the process. In 2009, FPL began recovering, under the capacity clause in accordance with the FPSC's nuclear cost recovery rule, pre-construction costs associated with FPL's planned nuclear units and carrying charges (equal to the pretax AFUDC rate) on construction costs associated with the addition of approximately 400 mw of baseload capacity. Substantially all of these costs are subject to a prudence review by the FPSC. The same rule provides for the recovery of construction costs, once the new capacity goes into service, through a base rate increase.

NextEra Energy Resources – NextEra Energy Resources' net income for the three months ended March 31, 2009 and 2008 was $252 million and $164 million, respectively, an increase of $88 million. The primary drivers, on an after-tax basis, of this increase were as follows:

	Increase (Decrease) Three Months Ended March 31, 2009 (millions)
New investments [a]	$ 58
Existing assets [a]	(31)
Full energy and capacity requirements services and trading	(6)
Asset sale	3
Interest expense, differential membership costs and other	8
Change in unrealized mark-to-market non-qualifying hedge activity [b]	82
Change in OTTI losses on securities held in nuclear decommissioning funds, net of OTTI reversals	(26)
Net income increase	$ 88

a) Includes PTCs and ITCs on wind projects and ITCs on solar projects as well as tax benefits under the Recovery Act (see Note 4) but does not include allocation of interest expense or corporate general and administrative expenses. Results from new projects are included in new investments during the first twelve months of operation. A project's results are included in existing assets beginning with the thirteenth month of operation.
b) See Note 2 and discussion above related to derivative instruments.

The increase in NextEra Energy Resources' results from new investments reflects the addition of over 1,300 mw of wind generation during or after the first quarter of 2008 and the state and convertible ITCs tax benefits (see Note 4). Results from NextEra Energy Resources' existing asset portfolio decreased primarily due to unfavorable market conditions in the ERCOT region, a refueling outage at the Duane Arnold nuclear facility and lower wind generation primarily due to a particularly strong wind resource in the prior quarter. These decreased results from the existing asset portfolio were partially offset by the absence of an unplanned outage in 2008 at the Seabrook nuclear facility, favorable commodity margins from NextEra Energy Resources' retail energy provider and the settlement agreement.

NextEra Energy Resources' first quarter 2009 financial results reflect lower gains from its full energy and capacity requirements services and trading activities. Full energy and capacity requirements services include load-following services, which require the supplier of energy to vary the quantity delivered based on the load demand needs of the customer, as well as various ancillary services.

The asset sale represents the sale of wind development rights in 2009. The increase in interest expense, differential membership costs and other reflects the foreign tax benefit (see Note 4), partially offset by higher interest expense and corporate general and administrative costs due to growth of the business.

EXHIBIT___(LK-5)

FPL GROUP.

FPL Group, Inc.
Corporate Communications Dept.
Media Line: (305) 552-3888
April 28, 2009

FOR IMMEDIATE RELEASE

NOTE TO EDITORS: This news release reflects the earnings report of FPL Group, Inc. Reference to the corporation and its earnings or financial results should be to "FPL Group" and not abbreviated using the name "FPL" as the latter is the name/acronym of the corporation's electric utility subsidiary.

FPL Group announces solid first quarter earnings for 2009

- NextEra Energy Resources reports strong results
- Difficult economy continues to challenge Florida Power & Light Company
- FPL Group raises adjusted earnings per share expectations to a range of $4.20 to $4.40 for 2009 and $4.65 to $5.05 for 2010

JUNO BEACH, Fla. – FPL Group, Inc. (NYSE: FPL) today reported 2009 first quarter net income on a GAAP basis of $364 million, or $0.90 per share, compared with $249 million, or $0.62 per share, in the first quarter of 2008. On an adjusted basis, FPL Group's earnings were $364 million, or $0.90 per share, compared with $305 million, or $0.76 per share, in the first quarter of 2008. Adjusted earnings exclude the mark-to-market effects of non-qualifying hedges and the net effect of other than temporary impairments (OTTI) on certain investments, both of which relate to NextEra Energy Resources.

FPL Group management uses adjusted earnings, which is a non-GAAP financial measure, internally for financial planning, for analysis of performance, for reporting of results to the Board of Directors and as input in determining whether certain performance targets are met for performance-based compensation under the company's employee incentive compensation plans. FPL Group also uses earnings expressed in this fashion when communicating its earnings outlook to analysts and investors. FPL Group management believes that adjusted earnings provide a more meaningful representation of FPL Group's fundamental earnings power. The attachments to this news release include a reconciliation of historical adjusted earnings to net income, which is the most directly comparable GAAP measure.

"FPL Group had a very good first quarter, with adjusted earnings per share rising 18 percent year over year, largely as a result of strong results from our NextEra Energy Resources subsidiary. At Florida Power & Light, we announced proposed investments that will significantly improve the electrical system for our customers – specifically, a large-scale deployment of 'smart grid' technology in Miami, and a new natural gas pipeline to provide increased energy security. As pleased as we are with FPL Group's current results, we are even more optimistic about the future. The reason is simple: We believe that the policy climate in the nation is trending in a direction highly favorable to power companies with low emissions profiles and significant clean-energy fleets," said FPL Group Chairman and CEO Lew Hay.

Florida Power & Light Company
FPL Group's rate-regulated utility subsidiary, Florida Power & Light Company, reported first quarter net income of $127 million, or $0.31 per share, compared with $108 million, or $0.27 per share, for the prior-year quarter. The weak economy, however, continued to have a negative impact on FPL. Sales declined for the quarter on a year-over-year basis, as did the average number of customers and usage per customer.

FPL's improved results were driven by a 10 percent reduction in operations and maintenance expenses compared to last year's first quarter, with much of that reduction attributable to timing of expenses in 2009. In addition, in March of this year, FPL, along with certain NextEra Energy Resources subsidiaries, signed a settlement agreement with the U.S. government dismissing lawsuits related to spent nuclear fuel disposal. The total settlement helped FPL Group's net income by about 4 cents per share, half of which was at FPL.

Other key developments:

- In March, FPL filed a rate proposal with the Florida Public Service Commission (PSC) that would support investment in improving fuel efficiency, generating cleaner energy and enhancing system reliability, while keeping customer bills low. Under the company's proposal, the typical 1,000 kilowatt-hour residential customer bill would decrease by an estimated $4.92 monthly, or 4.5 percent, from $109.55 to $104.63 on Jan. 1, 2010. This bill estimate reflects an increase in base rates that would be more than offset by reductions in the cost of fuel based on Feb. 9, 2009 fuel price projections for 2010 as well as improvements in fuel efficiency.
- In April, FPL filed a proposal with the PSC for the construction of a new underground natural gas pipeline in Florida to meet increasing demand for natural gas as a clean fuel for generating electricity while helping to diversify and secure the state's access to natural gas supplies. The pipeline, approximately 300 miles long, is proposed for construction in the eastern portion of the state from Palm Beach County in the south to Bradford County in the north.
- Also in April, FPL announced its "Energy Smart Miami" initiative. The initiative has the potential to be the most extensive and holistic smart grid implementation in the country. The backbone will be the deployment of more than 1 million advanced wireless "smart meters" to every home and most businesses in Miami-Dade County, which will be connected by a two-way wireless network, along with expected pilot programs involving renewable energy integration, deployment of plug-in hybrid electric vehicles and consumer technology trials of in-home energy displays and home energy controllers.

NextEra Energy Resources
NextEra Energy Resources, the competitive energy business of FPL Group with generating facilities in 25 states and Canada, reported first quarter net income on a GAAP basis of $252 million, or $0.62 per share, compared with $164 million, or $0.41 per share, in the prior-year quarter. On an adjusted basis, NextEra Energy Resources' earnings were $252 million, or $0.62 per share, compared with $220 million, or $0.55 per share, in the first quarter of 2008.

NextEra Energy Resources' first quarter adjusted earnings per share contribution rose by 13 percent over the prior-year quarter. These results were driven primarily by new investments, specifically new wind generation facilities. Included in this category are the favorable impacts of state investment tax incentives and the American Recovery and Reinvestment Act of 2009. Adjusted earnings from the existing portfolio, which includes both the contracted and merchant segments, declined versus the year ago quarter. The contracted segment was down due primarily to a refueling outage at one of our nuclear plants this year and lower earnings at one of the company's natural gas-fired facilities in the Northeast. Earnings from the merchant assets in the Electric Reliability Council of Texas (ERCOT) were down due to softer market conditions, partially offset by incremental contributions from the company's retail provider, Gexa. The merchant assets in the New England Power Pool (NEPOOL) were up 3 cents owing to the absence of an unplanned outage that occurred during last year's first quarter. The existing wind portfolio was down compared to last year's first quarter primarily reflecting a weaker wind resource. NextEra Energy Resources' results also benefited from an additional equity investment made in its Canadian operations that allowed the company to reduce previously deferred taxes.

In late January, the Public Utility Commission of Texas (PUCT) approved the state's Competitive Renewable Energy Zone initiative, a collaborative effort by the PUCT, ERCOT and interested stakeholders to deliver more renewable wind energy to customers in the state. The PUCT voted to implement an approximately $5 billion transmission build-out, awarding 11 percent of the total, or approximately $565 million, to Lone Star Transmission, an FPL Group subsidiary. Lone Star is expected to add approximately 250 miles of 345 kilovolt lines capable of transporting a significant amount of renewable energy from West Texas to the Dallas-Ft. Worth area.

Corporate and Other
The loss in Corporate and Other declined to $15 million in the first quarter of 2009 from $23 million in the first quarter of 2008.

Outlook
FPL Group believes it is well positioned for earnings growth and now believes the company will deliver adjusted earnings per share for 2009 and 2010 in a higher range than previously announced. For 2009, the new adjusted earnings per share range is $4.20 to $4.40 and for 2010 the new range is $4.65 to $5.05. Please see the accompanying cautionary statements for a list of risk factors that may affect future earnings.

As always, FPL Group's adjusted earnings expectations assume, among other things, normal weather and operating conditions, no further decline in the national or Florida economy, a reasonable capital markets atmosphere, and exclude the mark-to-market effect of non-qualifying hedges, OTTI, and the cumulative effect of adopting new accounting standards, if any, none of which can be determined at this time.

As previously announced, FPL Group's first-quarter earnings conference call is scheduled for 9 a.m. EDT on Tuesday, April 28, 2009. The webcast is available on FPL Group's Web site by accessing the following link, http://www.FPLGroup.com/investor/contents/investor_index.shtml. The slides and earnings release accompanying the presentation may be downloaded at www.FPLGroup.com beginning at 7:30 a.m. EDT today. For people unable to listen to the live webcast, a replay will be available for 90 days by accessing the same link as listed above.

EXHIBIT___(LK-6)

CONFIDENTIAL

INFORMATION

REDACTED

EXHIBIT___(LK-7)

CONFIDENTIAL

INFORMATION

REDACTED

EXHIBIT___(LK-8)

CONFIDENTIAL

INFORMATION

REDACTED

EXHIBIT __(LK-9)

Florida Power & Light Company
Docket No. 080677-EI
SFHHA's Second Set of Interrogatories
Interrogatory No. 119
Page 1 of 1

Q.
Interrogatories Directed to Ms. Kim Ousdahl:

Regarding Schedule C-36. For 2009 and 2010, please describe each of the major factors that cause the increases in non-fuel operations and maintenance expenses from each prior year (2009 compared to 2008 and 2010 compared to 2009). Your answer should explain why each factor contributes to the increase.

A.
See Attachment No. 1.

Florida Power Light Company
Docket No. 080677-EI
SFHHA's Second Set of Interrogatories
Question No. 119
Attachment No. 1
Page 1 of 8

Q. Interrogatories Directed to Ms. Kim Ousdahl:

Regarding Schedule C-36. For 2009 and 2010, please describe each of the major factors that cause the *increases in non-fuel operations and maintenance* expenses from each prior year (2009 compared to 2008 and 2010 compared to 2009). Your answer should explain why each factor contributes to the increase.

A. **Non-fuel O&M Expenses**

Expense Type		($000)	Major Factor Increase / (Decrease)
2008 Corporate Total	**$**	**1,306,728**	
Base O&M	$	135,912	See Attached
Revenue Enhancement	$	11,454	See Attached
Other	$	(3,770)	Less than 3.0%, not material
Total Increase / (Decrease)	**$**	**143,596**	
2009 Corporate Total	**$**	**1,450,324**	
2009 Corporate Total	**$**	**1,450,324**	
Base O&M	$	118,358	See Attached
Revenue Enhancement	$	1,785	See Attached
Other	$	(435)	Less than 0.4%, not material
Total Increase / (Decrease)	**$**	**119,708**	
2010 Corporate Total	**$**	**1,570,032**	

Non-Fuel O&M Expenses
(Base O&M)
2008 - 2009

Unit		($000)	Major Factor Increase / (Decrease)
2008 Corporate Total	$	1,298,626	
Distribution		(8,900)	Forecasted reduction in customer growth
		(1,258)	Staff support reductions
		5,800	Higher level of Storm Secure work
	$	(4,358)	
Customer Service	$	2,184	Increase is attributed to activities associated with field services functions. The increase is driven primarily by higher staffing, training and vehicle cost.
		2,054	Increase is attributed to activities associated with meter reading, billing and payment processing functions. The increase is primarily driven by customer growth and new meter sets, vehicle, equipment, maintenance and postage expense.
		1,640	Increase is attributed to activities associated with credit and collection functions to continue to minimize bad debt. Increase is driven primarily by higher staffing, postage, equipment and material and collection agency expense.
		1,523	Increase is attributed to support services expenses associated with increased activities to support customer service including complaint handling, customer advocacy, business continuity, employee development and quality training.
		1,373	Increase is attributed to care center expense primarily associated with expected increases in call volume, management and quality support staff, telecommunications and maintenance expense.
		1,208	Increase in Automated Metering Infrastructure (AMI) expense driven by costs associated with the current operational phase of the project.
		920	Increase in Uncollectible Accounts Receivable based on current economic assumptions
	$	10,901	
Transmission	$	1,210	Regulatory commitments that include telecommunication/software licenses and increased staffing required by NERC for SCC
		950	Vegetation expenditures required to comply with NERC standard FAC.
		500	Training and recertification programs to support continuing compliance with reliability standards
		435	Pole inspection programs and storm hardening required by the FPSC
		1,700	Continuing and additional condition assessment/life extension activities on aging infrastructure and initiatives to perform real time statistical analysis of equipment performance
		1,380	Transfer responsibility for Distribution underbuilt program to Transmission & Substation from Distribution
	$	6,175	
Power Generation	$	9,984	Structural Maintenance & Reliability Projects
		9,746	West County Energy Center Operational
		3,492	Scherer Unit 4 Performance Fee
		(9,322)	No overhaul for Scherer Unit 4 in 2009
		(915)	Other (net)
	$	12,985	
Engineering, Construction, Corp S	$	281	Merit increases impact
		675	Increase in salaries due to filling of vacant positions in 2008
		385	O&M impact of 4 new approved positions
		890	Increased Maintenance - increase in Substation/Svc Center/Courier maintenance costs primarily driven by fuel and utilities increases along with 11 new substations.
		627	Facility Optimization initiative to maximize utilization of existing space to accommodate needs
		505	Energy Efficient Initiatives to support green initiative and reduce costs
		210	NERC Regulatory requirement to upgrade security access to Transmission related facilities
		200	Storm Hardening to address 2008 Strom Dry Run action items
		(201)	Non-recurring projects from 2008 partially offset by deferred projects from 2008
		56	Other - miscellaneous
	$	3,628	

Non-Fuel O&M Expenses
(Base O&M)
2008 - 2009

Unit		($000)	Major Factor Increase / (Decrease)
Nuclear	$	7,700	Inflation at 2%
		11,000	Regular Payroll (headcount increase; operations pipeline and Fatigue Rule impact)
		(5,100)	Overtime Payroll (impact of headcount increase and Fatigue Rule)
		14,600	Discretionary projects
		(4,400)	Short Notice Outages (not budgeted, but in 2008 actuals)
		(6,500)	Turkey Point Excellence (ramp down of project)
		(4,100)	PSL Spent Fuel Storage Loading Campaigns (not budgeted in 2009 - only occurs as necessary)
		3,200	PSL-PTN-ENG Station Projects
		(1,300)	Other
	$	15,370	
Accounting, Financial & Other	$	43,818	AEGIS Environmental Insurance Policy commutation payment, only credited in 2008
		2,483	Payroll Accrual - Driven by increase in budgeted payroll dollars
		2,034	St. Lucie Participation Credit - 2009 credit lower due to differences in the outage schedules
		1,616	Centerpoint and Entergy mutual assistance - Billing for assistance provided during hurricane
		(9,000)	Estimated DOE Settlement - credit budgeted in 2009
		(4,440)	Pension & Welfare Credit - increased credit driven by an increase in capitalized payroll expenses ($3,634) and PWTI rate ($806K) vs. 2008. 2008 PWTI rate was 7.36% and 2009 was 7.62%
		(2,833)	Affiliate Management Fee - Driven by an increase in cost pool expenses and an increase in the Massachusetts Formula allocation rate
		(4,776)	2008 HR Severance Accrual
		684	Other
	$	29,486	
Human Resources	$	5,405	Medical: The 2008 to 2009 increase is being driven by a blended medical trend of 9.28% (12% bargaining, 8% nonbargaining), which is in line with national medical increases in trends. For 2009, the resulting forecast was reduced by ~$1.2M, primarily reflecting increased employee contributions.
		2,969	FAS 112: Primary cost drivers include actual disability experience, and to a lesser degree assumptions regarding discount rates and medical trends. FPL's 2009 expense reflects an average of historical results.
		10,235	FAS 87: Primary driver of year over year increase is the impact of a significant negative return on assets (credit budget) in 2008 as well as the impact of a union arbitration decided in October of 2008. These factors were offset by an expected increase in the discount rate.
		5,165	Corporate Incentive Program: 2008 to 2009 cost drivers include employee headcount, merit and market pay increases, as well as corporate, business unit, and individual performance against established performance indicators.
		(691)	Other: Mainly driven by a decrease in FAS 106 Retiree Medical (due to fewer eligible emloyees) and other miscellaneous items, offset by an increase in Workers' Comp (due to lowered expectation of settled claims).
	$	23,082	
Information Management	$	4,146	Represents the O&M component for the second year of the Future Enterprise Network Architecture project (FENA). The increase in O&M from 2008 can be mainly attributed to the need of circuit redundancy with carrier diversity services required during the implementation stages to reduce the risk of network outages at critical sites such as data centers, nuclear plants, care centers, and dispatch centers while our wide area network is being upgraded. There is also professional services and equipment maintenance included in this increase.
	$	1,090	Increase represents the consulting services associated with two information security initiatives in 2009: (a) Information Security Provisioning tool replacement ($340k) to eliminate the current system limitations, manual work and multiple interfaces required to complete system requests; and (b) Identity Management Role Based & Process Re-engineering ($795) to streamline the current access control administration process which is highly customized and requires extensive human intervention and also makes it difficult to evaluate security issues such as Segregation of Duties violations (SOD).
	$	1,390	Mainly attributed to the utility portion new maintenance contracts associated with the Nuclear Asset Management (NAMS) software as part of the current implementation.
		2,232	Standard HR compensation programs as well as projected increase in headcount to be able to execute our Information Technology enterprise projects
		354	Misc
	$	9,213	

Non-Fuel O&M Expenses
(Base O&M)
2008 - 2009

Unit		($000)	Major Factor Increase / (Decrease)
Financial Business Unit	$	1,164	Greater nuclear liability insurance due to higher projected premiums and lower projected nuclear liability and other distributions in 2009.
		3,171	Greater executive SERP thrift program and Board of Director pension program attributable to anticipated growth in FPL stock price.
		2,600	Greater executive miscellaneous expense.
		7,182	Greater nuclear property insurance due to lower distributions, additional storm premium, and site loss penalty included in 2009.
		221	Greater executive industry dues, $0.5 mil and greater audit and professional fees, $0.6 mil, partially offset by discontinuation of the Research and Development program, $(0.2) mil, transfer of responsibility for printing and fulfillment of annual report to Marketing & Communications, $(0.3) mil, and net favorable other, $(0.4) mil.
		3,345	Greater executive deferred compensation due to anticipated growth in stock market investments and projected increases in executive stock awards, also greater executive admin-assistant salaries, partially offset by lower executive incentives, severance, and relocation, also greater credits for the executive portion of the affiliate management fee.
	$	17,682	
Regulatory Affairs	$	2,752	Rate Case expenses incurred
		1,420	Regulatory Affairs Department annualized incremental payroll for 11 new positions
		(107)	Net other minor items
	$	4,065	
General Counsel	$	737	Payroll. Headcount increases - $160K. Under in head count in 2008 - $242. Incentive, merit increases and raises - $635K.
		(336)	Office & Employee Related. Response to economic down turn by reducing travel, entertainment, third party training and reduction of office expenses.
		(491)	Outside Services. Increased staffing levels will enable FPL attorneys to handle matters previously assigned to outside counsel.
		2,474	Injuries and Damages. Due to an increase in the Self-insured retention from $ 2 million to $3 million in 2009, the budget was increased in anticipation of these increased costs. Our claims department calculated an annual impact of $2 million dollars. The remainder of the increase is to bring the budget up to the normalized level as 2008 was an unusually low year.
	$	2,384	
Strategy, Policy, and Bus Proc		5,101	The R74000 is a new business unit. Three sections, Security, Aviation and Environmental Services, were previously under different business units and two new sections, Operational Excellence and Strategic Initiatives, were combined to form the Strategy, Policy and Business Process Improvement business unit. • The salary variance of $3,377,191 is mainly due to new personnel in Strategic Initiatives and Operational Excellence as well as pay increases in the other sections. • The office supplies and expenses variance of $1,352,613 is mainly due to aircraft fuel expenses are higher, new software for Security, relocation and software cost for Strategic Initiatives and Operational Excellence. • The outside services employed variance of $912,764 is mainly due to a classification change between 2008 and 2009. • The miscellaneous general expense variance of $713,755 is mainly due to Environmental Liabilities Reserve (ELR). • The maintenance of general plant variance $143,567 is mainly due to general aircraft maintenance cost increases.
	$	5,101	
Other Base O&M	$	299	Less than 0.2% of increase, not material
2009 Corporate Total	$	1,434,438	
Total Variance 2008 vs. 2009	$	136,912	

Non-Fuel O&M Expenses
(Revenue Enhancement)
2008 - 2009

Unit	($000)	Major Factor Increase / (Decrease)
2008 Corporate Total	**$ 16,275**	
Customer Service	10,895	This increase in O&M is due to the planned growth in the Performance Contracting business. Performance Contracting is planning to increase sales revenue by 60% in 2009 vs. 2008. The projected increase in O&M is to support the planned growth.
	590	This increase in O&M is due primarily to the administrative expense related to supporting the business growth.
	$ 11,485	
Other	**$ (31)**	Less than 0.3% of increase, not material
2009 Corporate Total	**$ 27,729**	
Total Variance 2008 vs. 2009	**$ 11,454**	

Non-Fuel O&M Expenses
(Base O&M)
2009 - 2010

Unit		($000)	Major Factor Increase / (Decrease)
2009 Corporate Total	$	1,434,438	
Distribution		5,100	Forecasted increase in customer growth
		6,600	Higher level of Storm Secure work
		(2,451)	Staff support reductions
	$	9,249	
Customer Service	$	(5,783)	Decrease is attributed to lower uncollectible expense. This improvement is driven by the continued application of credit and collections resources to minimize bad debt.
		4,765	Increase is attributed to the first year of full-scale deployment of the Automated Metering Infrastructure program (2010).
		2,406	Increase is attributed to activities associated with meter reading, billing and payment processing functions. The increase is primarily driven by customer growth and new meter sets, vehicle, equipment, maintenance, postage expense and centralization of key activities. This expense is partially offset by savings associated with Advanced Metering Infrastucture.
		2,158	Increase is attributed to activities associated with field services functions. The increase is driven primarily by staffing, training and vehicle cost.
		1,637	Increase is attributed to care center expense primarily associated with expected increases in call volume, management and quality support staff, telecommunications and maintenance expense.
		1,143	Increase is attributed to support services expenses associated with increased activities to support customer service including customer advocacy, business continuity, employee development and billing and payment options development.
		632	Increase is attributed to credit and collection activities to minimize bad debt expense. This increase is associated with enhancements to the credit and collections model, and collection agency expense.
	$	6,958	
Transmission		9,843	The primary cost drivers of the variance are initiatives associated with NERC reliability standards and FPL's reliability enhancement program contributes to the increase in projected expenditures for 2010. This includes development and implementation of programs, standard modules, external audits, self-assessments, training and certification programs, reliability studies, and support for continuing compliance with NERC reliability standards.
		1,600	Additional condition assessment and life extension activities for Protection and Control equipment and new and expanded training and re-certification programs also account for projected increases for 2010 for Transmission O&M.
		543	Other
	$	11,986	
Power Generation	$	10,179	Scherer Unit 4 Semi Annual Overhaul
		9,172	West County Energy Center Operational
		3,213	Payroll & Routine Maintenance (Inflation)
		1,657	Scherer maintenance increase based on condition assessment
		1,200	SJRPP maintenance based on condition assessment
		(4,490)	Scherer Performance Fee (reduced) due to overhaul 2010
		(6,113)	Structural Maintenance & Reliability Projects reduced to level dictated by condition assessment
		82	Other (net)
	$	14,900	
Engineering, Construction, Corp Si		(1,724)	Non-recurring projects from 2009 partially offset by CPI growth for expenses and merit increases
	$	(1,724)	
Nuclear	$	8,000	Inflation at 2%
		8,700	Regular Payroll (headcount increase; additional operations pipeline and Fatigue Rule impact)
		(14,500)	Non-recurring discretionary projects (2009 budget only)
		5,000	NRC Fees
		6,100	Outage Reserves (future years' scope driven)
		6,000	PSL Spent Fuel Storage Loading Campaigns (not budgeted in 2009 - only occurs as necessary)
		4,600	PSL-PTN-ENG Station Projects
		3,700	Other
	$	27,924	

Non-Fuel O&M Expenses
(Base O&M)
2009 - 2010

Unit		($000)	Major Factor Increase / (Decrease)
Accounting, Financial & Other	$	(12,200)	Pension & Welfare Credit - increased credit driven by an increase in capitalized payroll expenses ($1,892) and PWTI rate ($10,338) vs. 2008. 2009 PWTI rate was 7.62% and 2010 was 10.71%
		(4,093)	Affiliate Management Fee - Driven by an increase in cost pool expenses and an increase in the Massachusetts Formula allocation rate
		(2,603)	St. Lucie Participation Credit - 2009 credit lower due to differences in the outage schedules
		1,010	Payroll Accrual - Driven by increase in budgeted payroll dollars
		9,000	DOE Settlement - credit budgeted in 2009
		(1,317)	Other
	$	(10,203)	
Human Resources	$	12,400	The increase is driven by greater medical services costs, as well as projected increases in the enrolled population.
		19,937	FAS 87: The year over year forecasted increase results from the amortization of the significant negative investment returns from 2008 which will continue to impact the FAS 87 evaluation until 2014. The forecast assumes the actual return in 2010 will equal the Plan's long term assumption of 7.75%.
		4,600	401K: The two primary drivers of the increase include: changes in population (both number participating and level of contributions) and changes to employee base pay. In addition, there is also a projected $2 million dollar increase in 2010 for the planned implementation of auto-enroll features.
		2,400	Long Term Incentive Programs: The 2010 budget includes continued amortization of prior year grants over the vesting periods and amortization of grants planned for 2010 for retention and competitive pay practice purposes.
		2,685	Other: Main drivers include an increase in Dental (mainly driven by an 8% trend), an increase to the Corporate Incentive Program (based on expected company performance and employee headcount), and an increase of programs in Other Benefits.
	$	42,021	
Information Management	$	6,358	Increase mainly attributed to cost associated with the Customer Information System II replacement project. The current system is old, highly customized/complex and inflexible, to the point that we are spending more on support than new enhancements.
		4,047	Increase represents the costs required during the second year of the project to relocate the Juno Beach Data Center to new out-of-state Data Center Site. The objective is to achieve greater geographic diversity for our secondary data center and drastically reduce the impact to business operation during a storm event.
		(148)	Other.
	$	10,257	
Financial Business Unit		2,497	Projected increases of $1.9 for non-executive new positions, merit, relocation, recruiting, and annual bonuses and $0.6 mil for greater executive payroll, merit, and annual incentive bonus.
		1,164	Greater audit, bank, and professional fees.
		1,230	Greater liability coverage for FPL's liability exposure related to a nuclear energy hazard, third party liability, and directors and officers insurance, due to an expected increase in capacity, market conditions, and nature of the company's business and loss history, $1.0. Greater non-nuclear property insurance, $0.4 mil, partially offset by lower storm related site loss experience penalty, $(0.2).
		924	Projected increase in executive stock based compensation awards mainly driven by retentions and inflation, and projected increase in the executive deferred compensation balance driven by stock market growth projections, largely offset by increase in Executive portion of the Affiliate Management fee due to the change in the Massachusetts formula rate from 32.36% to 34.24%, as well as due to additional services needed to support the affiliate growth at FPLE.
		741	Other
	$	6,556	
Regulatory Affairs	$	(2,721)	Rate Case expenses no longer incurred
		500	FERC Regulatory Commission expenses
		318	Employee Compensation: pay rate increase and incentive increase
		65	Net other minor items
	$	(1,838)	
Other	$	2,272	Less than 2.0% of increase, not material
2010 Corporate Total	$	1,552,796	
Total Variance 2009 vs. 2010	$	118,358	

Non-Fuel O&M Expenses
(Revenue Enhancement)
2009 - 2010

Unit	($000)	Major Factor Increase / (Decrease)
2009 Corporate Total	**$ 27,729**	
Customer Service	1,567	This increase in O&M is due to the planned growth in the Performance Contracting business. Performance Contracting is planning to increase sales revenue by 6% in 2010 vs. 2009. The projected increase in O&M is to support the planned growth.
	218	This increase in O&M is due primarily to the administrative expense related to supporting the business growth.
	$ 1,785	
2010 Corporate Total	**$ 29,514**	
Total Variance 2009 vs. 2010	**$ 1,785**	

EXHIBIT___(LK-10)

Q.
Regarding Schedule C-35 for the 2010 test year. Of the data that appear in this schedule, please identify which amounts are capital and which are expenses for each year provided and separately identify the amounts that should be included in base rates and the Company's various riders for each year.

A.
MFR C-35 line 3 – Gross Payroll - See Attachment No. 1 for the requested breakdown of amounts that appear on MFR C-35 line 3. The source of the amounts provided on MFR C-35 line 3 for 2006 through 2008 is the FERC Form 1, which provides an accounting view of costs classified as payroll. The source of the amounts provided on MFR C-35 line 3 for 2009 and 2010 is the FPL corporate budget system, which provides a management view of payroll. For comparability across years, the response to this interrogatory is from the FPL corporate budget system for 2006 through 2010.

MFR C-35 Fringe Benefits -- See Attachment No. 2.

FPL Utility
Gross Payroll

	O&M Expenses		Capital		Other	Total
Year	Base Recoverable	Clause Recoverable	Base Recoverable	Clause Recoverable		
2006	$ 637,917,353	$ 19,269,821	$ 188,940,360	$ 1,178,469	$ 9,496,054	$ 856,802,058
2007	686,309,937	21,691,062	210,673,988	879,986	12,160,124	931,715,097
2008	714,860,295	22,416,627	216,755,824	1,250,731	13,685,927	968,969,403
2009	722,471,814	27,748,103	243,763,197	3,956,611	9,274,829	1,007,214,554
2010	765,261,494	27,867,388	254,621,125	5,269,533	9,630,794	1,062,650,334

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SFHHA's 10th Set of Interrogatories – Question 297
MFR C-35 2006–2010 Benefits Expenses ($000) Categorized by Expense vs. Capital

	2010			2009			2008			2007			2006		
Benefit Line Items (C-35)	O&M	Capital	Total	O&M	Capital	Total	O&M	Capital	Total	O&M	Capital	Total	O&M	Capital	Total
Life Insurance	1,058	373	1,431	1,012	327	1,339	1,040	285	1,325	781	339	1,120	710	753	1,463
Medical Insurance	69,572	25,965	95,537	61,785	21,158	82,943	59,812	17,773	77,585	54,131	17,174	71,305	52,507	14,343	66,850
Pension Plan (FAS 87)	-38,982	-16,737	-55,719	-55,487	-20,169	-75,656	-66,932	-18,932	-85,864	-60,168	-17,026	-77,194	-64,332	-14,408	-78,740
Employee Savings Plan	23,802	8,900	32,702	20,884	7,218	28,102	22,052	6,108	28,160	20,249	6,414	26,663	20,152	5,577	25,729
Federal Insurance Contributions Act (FICA)	52,578	18,831	71,409	51,539	16,727	68,266	50,883	13,620	64,503	48,200	13,272	61,472	45,843	11,866	57,709
Federal & State Unemployment Taxes	937	340	1,277	918	302	1,220	832	251	1,083	2,143	634	2,776	2,266	592	2,858
Workers' Compensation	6,393	2,386	8,779	6,259	2,242	8,501	6,496	2,238	8,734	6,658	2,563	9,221	7,977	2,031	10,008
Educational Assistance	1,193	459	1,652	898	302	1,200	641	183	824	558	225	783	533	232	765
Employee Welfare	2,893	1,882	4,775	2,055	1,424	3,479	2,070	1,627	3,697	7,415	1,323	8,738	5,730	2,192	7,922
Post Retirement Benefits (FAS 106)	16,428	6,172	22,600	16,513	5,709	22,222	18,338	5,191	23,529	19,338	5,531	24,869	22,310	5,917	28,227
Post Employment Disability Benefit (FAS 112)	5,294	1,981	7,275	5,216	1,786	7,000	2,484	1,547	4,031	8,824	1,213	10,036	4,164	1,562	5,726
Dental Insurance	4,649	1,751	6,400	4,092	1,408	5,500	4,114	1,201	5,315	3,745	1,202	4,986	3,653	1,151	4,804
Nuclear Child Development Center	237	0	237	251	0	251	217	0	217	216	0	216	128	0	128
TOTAL Fringe Benefits			198,355			164,367			133,139			144,981			133,449

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Exhibit __(LK-10), Page 3 of 3

EXHIBIT___(LK-11)

FLORIDA POWER AND LIGHT
SFHHA ADJUSTMENTS TO REFLECT PRODUCTIVITY GAINS
TEST YEAR ENDING DECEMBER 31, 2010
($ MILLIONS)

Source: Response to SFHHA Interrogatory No. 297 and Burea of Labor Statistics website

Assumed 2.0% Annual Productivity Factor Based on Historical Data Presented Below

	O&M Amount	Productivity Factor	Productivity Reduction
O&M Base Recovery Payroll 2010	765.261	0.0404	(30.917)
O&M Payroll Tax 2010 - Sch C-20	49.384	0.0404	(1.995)
O&M Base Recovery Fr. Benefits	89.286	0.0404	(3.607)
Total Productivity Reduction			(36.519)

BLS Productivity Statistics

Series Id: PRS85006093
Duration: index, 1992 = 100
Measure: Output Per Hour
Sector: Nonfarm Business

Year	Qtr1	Qtr2	Qtr3	Qtr4	Annual	% Increase
1998	108.356	108.675	109.902	110.476	109.358	
1999	111.455	111.704	112.487	114.415	112.521	2.9%
2000	113.914	115.938	115.713	116.824	115.687	2.8%
2001	116.689	118.288	118.826	120.574	118.577	2.5%
2002	122.685	122.88	124.208	124.098	123.468	4.1%
2003	125.197	126.903	130.064	129.963	128.034	3.7%
2004	130.225	131.73	132.242	132.245	131.614	2.8%
2005	133.167	133.394	134.687	134.195	133.862	1.7%
2006	134.832	135.642	135.086	134.938	135.123	0.9%
2007	134.731	136.326	138.665	138.482	137.049	1.4%
2008	139.385	140.98	141.732	141.533	140.897	2.8%
2009	142.079					
5 Year Simple Average						1.9%
10 Year Simple Average						2.8%
Most Recent Annualized 1st Qtr						1.9%

FLORIDA POWER AND LIGHT
SFHHA ADJUSTMENTS TO REFLECT PRODUCTIVITY GAINS
TEST YEAR ENDING DECEMBER 31, 2010
($ MILLIONS)

Computation of Fringe Benefits
SFHHA Interrogatory No. 297

	2010 Fringe O&M Reflected on #297		2010 Fringe O&M Without PR Taxes
Life Insurance	1.058		1.058
Medical Insurance	69.572		69.572
Pension Plan	-38.982		-38.982
Employee Savings Plan	23.802		23.802
FICA - SB P/R Tax	52.578		
Fed & St Unemployment - SB P/R Tax	0.937		
Worker's Comp	6.393		6.393
Educational Assist	1.193		1.193
Employee Welfare	2.893		2.893
OPEB (SFAS 106)	16.428		16.428
Post Emp Disability Benefit	5.294		5.294
Dental Insurance	4.649		4.649
Nuclear Child Development Center	0.237		0.237
Total	146.052		92.537
Base Recovery Amount			89.286

O&M Payroll

Base Recovery Gross PR per No. 297	765.261494	96.5%
Clause Recovery Gross PR per No. 297	27.867388	3.5%
Total O&M Payroll	793.128882	100.0%

EXHIBIT___(LK-12)

Q.
Regarding Testimony of FPL Witness J. A. Stall

Regarding page 39:1-9 and Exhibit JAS-10. Please provide a detailed explanation of the reasons for the increase in annual O&M expenditures for St. Lucy and Turkey Point in the 2010 and 2011 plans as compared to 2008 actual expenditures.

A.
FPL's increase in annual O&M expenditures for 2010 and 2011, compared to 2008 actual expenditures, is approximately $43.5 million and $59.0 million, respectively. The major drivers of the variance are categorized as follows:

2010:

Nuclear Division Staffing: The increase is comprised of the following components: Year-to-year merit increases for Nuclear Division employees and an increase in staffing to address Operations staffing needs and Maintenance and Engineering College Program. The increase attributable to merit increases is approximately $6 million, and staffing increase is approximately $18.5 million.

NRC Licensing and Inspection Fees: The NRC has significantly increased the fees FPL must pay as a result of the nuclear units being regulated by the NRC. NRC licensing fees are charged at a per unit rate and inspection fees are charged at a per hour rate for services required. The increase is approximately $4.9 million.

Outages: Included in this variance are changes in actual costs associated with differences in the number and scope of refueling outages for St. Lucie and Turkey Point nuclear units in the two comparison years (2008 and 2010). The increase is approximately $7.9 million.

Projects: Projects are scope-driven and expenditures will vary from year to year. The net increase attributable to projects is approximately $3.8 million. See documents provided in FPL's response to SFHHA's Fifth Request for Production of Documents No. 71 for a list of projects.

Materials & Supplies: The increase is associated with costs for material and supplies to support daily maintenance activities and write-off of obsolete inventory due to equipment upgrades not related to the uprate projects. The increase is approximately $2.1 million.

2011:

Nuclear Division Staffing: The increase is comprised of the following components: Year-to-year merit increases for Nuclear Division employees and an increase in staffing to address Operations staffing needs and Maintenance and Engineering College Program. The increase attributable to merit increases is approximately $9.1 million, and staffing increase is approximately $23.3 million.

NRC Licensing and Inspection Fees: The NRC has significantly increased the fees FPL must pay as a result of the nuclear units being regulated by the NRC. NRC licensing fees are charged at a per unit rate and inspection fees are charged at a per hour rate for services required. The increase is approximately $7.2 million.

Outages: Included in this variance are changes in actual costs associated with differences in the number and scope of refueling outages for St. Lucie and Turkey Point nuclear units in the two comparison years (2008 and 2011). The increase is approximately $15.1 million.

Materials & Supplies: The increase is associated with costs for material and supplies to support daily maintenance activities and write-off of obsolete inventory due to equipment upgrades not related to the uprate projects. The increase is approximately $2.6 million.

EXHIBIT___(LK-13)

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Q.
Please provide a monthly history of nuclear production full time equivalent employees by department and in total for this function from January 2006 through December 2011 and provide an explanation for any year to year change (December to December) exceeding 2% in total for this function. For 2009, the Company should provide this information on a budgeted basis and on an actual basis for those months with actual data.

A.
See Attachment No. 1.

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Rate Case Interrogatory #291
Year over Year Increase

	Full Time Regular Employees	% Increase
2006 Actual	1,689.5	
2007 Actual	1,768.5	4.7%
2008 Actual	1,888.5	6.8%
2009 Actual & Budget	2,011.5	6.5%
2010 Budget	2,071.0	3.0%
2011 Budget	2,115.8	2.2%

Changes from 2006-2007:
FPL added staff to anticipate and ultimately compensate for attrition and retirements.
As part of the FPL Professional Training Pipeline, FPL had formed partnerships with both the Indian River State College and the Miami Dade Community College to train the next generation of workers, and has committed to accepting a fixed number into the Apprenticeship Program each year. Employee increases during 2007 resulted from this program, plus dedicated air conditioning maintenance employees (displacing contractors), as well as authorized increases in Nuclear Engineering to align with the standard fleet organization model based on the size of each station.

Changes from 2007-2008:
The majority of employee increases during 2008 were driven by the "pipeline". FPL increased the number of plant workers to allow for a smooth transition as experienced workers retire, while also preparing for anticipated industry growth over the next 10 years. Many of those hired were for licensed operator classes where employees are trained for extensive time frames prior to becoming productive. Other drivers included Capacity Clause security positions and project bound employees for a new major capital project (Extended Power Uprate) (payroll dollars for Capacity Clause and Extended Power Uprate are included in their respective Docket filings).

Changes from 2008-2009:
The main drivers for each of the projected years is the Apprenticeship Program and operations training pipeline. During 2009 only FPL also expects to hire additional project bound positions to support the new major capital project referenced for 2008, which is expected to last into 2013.

Changes from 2009-2010:
The main drivers for each of the projected years is the Apprenticeship Program and operations training pipeline.

Changes from 2010-2011:
The main drivers for each of the projected years is the Apprenticeship Program

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BRC Description	Ledger Date	Emp.Type	Emp.Status	Actual
R01044 - ENGINEERING SUPP SVC	200601	Exempt Regular	Bi-weekly Fixed	53
	200601	Non-Exempt	Bi-weekly Fixed	3
	200602	Exempt Regular	Bi-weekly Fixed	53
	200602	Non-Exempt	Bi-weekly Fixed	3
	200603	Exempt Regular	Bi-weekly Fixed	52
	200603	Non-Exempt	Bi-weekly Fixed	3
	200604	Exempt Regular	Bi-weekly Fixed	48
	200604	Non-Exempt	Bi-weekly Fixed	3
	200605	Exempt Regular	Bi-weekly Fixed	48
	200605	Non-Exempt	Bi-weekly Fixed	3
	200606	Exempt Regular	Bi-weekly Fixed	48
	200606	Non-Exempt	Bi-weekly Fixed	3
	200607	Bargaining	Bi-weekly Fixed	4
	200607	Exempt Regular	Bi-weekly Fixed	49
	200607	Non-Exempt	Bi-weekly Fixed	3
	200608	Exempt Regular	Bi-weekly Fixed	49
	200608	Non-Exempt	Bi-weekly Fixed	3
	200609	Exempt Regular	Bi-weekly Fixed	49
	200609	Non-Exempt	Bi-weekly Fixed	3
	200610	Exempt Regular	Bi-weekly Fixed	49
	200610	Non-Exempt	Bi-weekly Fixed	3
	200611	Exempt Regular	Bi-weekly Fixed	50
	200611	Non-Exempt	Bi-weekly Fixed	3
	200612	Exempt Regular	Bi-weekly Fixed	51
	200612	Non-Exempt	Bi-weekly Fixed	3
R01905 - ST LUCIE PLANT	200601	Bargaining	Bi-weekly Fixed	252
	200601	Exempt Regular	Bi-weekly Fixed	340
	200601	Non-Exempt	Bi-weekly Fixed	46
	200602	Bargaining	Bi-weekly Fixed	254
	200602	Exempt Regular	Bi-weekly Fixed	341
	200602	Non-Exempt	Bi-weekly Fixed	45
	200603	Bargaining	Bi-weekly Fixed	257
	200603	Exempt Regular	Bi-weekly Fixed	340
	200603	Non-Exempt	Bi-weekly Fixed	45
	200604	Bargaining	Bi-weekly Fixed	257
	200604	Exempt Regular	Bi-weekly Fixed	345
	200604	Non-Exempt	Bi-weekly Fixed	45
	200605	Bargaining	Bi-weekly Fixed	264
	200605	Exempt Regular	Bi-weekly Fixed	350
	200605	Non-Exempt	Bi-weekly Fixed	46
	200606	Bargaining	Bi-weekly Fixed	266
	200606	Exempt Regular	Bi-weekly Fixed	350
	200606	Non-Exempt	Bi-weekly Fixed	45
	200607	Bargaining	Bi-weekly Fixed	263
	200607	Exempt Regular	Bi-weekly Fixed	358

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BRC Description	Ledger Date	Emp.Type	Emp.Status	Actual
	200607	Non-Exempt	Bi-weekly Fixed	46
	200608	Bargaining	Bi-weekly Fixed	265
	200608	Exempt Regular	Bi-weekly Fixed	363
	200608	Non-Exempt	Bi-weekly Fixed	45
	200609	Bargaining	Bi-weekly Fixed	264
	200609	Exempt Regular	Bi-weekly Fixed	363
	200609	Non-Exempt	Bi-weekly Fixed	44
	200610	Bargaining	Bi-weekly Fixed	262
	200610	Exempt Regular	Bi-weekly Fixed	372
	200610	Non-Exempt	Bi-weekly Fixed	45.5
	200611	Bargaining	Bi-weekly Fixed	264
	200611	Exempt Regular	Bi-weekly Fixed	374.5
	200611	Non-Exempt	Bi-weekly Fixed	44.5
	200612	Bargaining	Bi-weekly Fixed	264
	200612	Exempt Regular	Bi-weekly Fixed	372.5
	200612	Non-Exempt	Bi-weekly Fixed	45.5
R01908 - PTN STATION	200601	Bargaining	Bi-weekly Fixed	272
	200601	Bargaining	Daily Variable	0
	200601	Exempt Regular	Bi-weekly Fixed	354.5
	200601	Non-Exempt	Bi-weekly Fixed	50
	200602	Bargaining	Bi-weekly Fixed	283
	200602	Bargaining	Daily Variable	0
	200602	Exempt Regular	Bi-weekly Fixed	354.5
	200602	Non-Exempt	Bi-weekly Fixed	49
	200603	Bargaining	Bi-weekly Fixed	294
	200603	Bargaining	Daily Variable	0
	200603	Exempt Regular	Bi-weekly Fixed	355.5
	200603	Non-Exempt	Bi-weekly Fixed	49
	200604	Bargaining	Bi-weekly Fixed	303
	200604	Bargaining	Daily Variable	0
	200604	Exempt Regular	Bi-weekly Fixed	356.5
	200604	Non-Exempt	Bi-weekly Fixed	49
	200605	Bargaining	Bi-weekly Fixed	301
	200605	Bargaining	Daily Variable	0
	200605	Exempt Regular	Bi-weekly Fixed	357.5
	200605	Non-Exempt	Bi-weekly Fixed	48
	200606	Bargaining	Bi-weekly Fixed	310
	200606	Bargaining	Daily Variable	0
	200606	Exempt Regular	Bi-weekly Fixed	355.5
	200606	Non-Exempt	Bi-weekly Fixed	48
	200607	Bargaining	Bi-weekly Fixed	312
	200607	Bargaining	Daily Variable	0
	200607	Exempt Regular	Bi-weekly Fixed	357.5
	200607	Non-Exempt	Bi-weekly Fixed	47
	200608	Bargaining	Bi-weekly Fixed	313

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BRC Description	Ledger Date	Emp.Type	Emp.Status	Actual
	200608	Bargaining	Daily Variable	0
	200608	Exempt Regular	Bi-weekly Fixed	348.5
	200608	Non-Exempt	Bi-weekly Fixed	48
	200609	Bargaining	Bi-weekly Fixed	313
	200609	Bargaining	Daily Variable	0
	200609	Exempt Regular	Bi-weekly Fixed	361.5
	200609	Non-Exempt	Bi-weekly Fixed	47
	200610	Bargaining	Bi-weekly Fixed	309
	200610	Bargaining	Daily Variable	0
	200610	Exempt Regular	Bi-weekly Fixed	360.5
	200610	Non-Exempt	Bi-weekly Fixed	50
	200611	Bargaining	Bi-weekly Fixed	305
	200611	Bargaining	Daily Variable	0
	200611	Exempt Regular	Bi-weekly Fixed	358.5
	200611	Non-Exempt	Bi-weekly Fixed	53
	200612	Bargaining	Bi-weekly Fixed	300
	200612	Bargaining	Daily Variable	0
	200612	Exempt Regular	Bi-weekly Fixed	360.5
	200612	Non-Exempt	Bi-weekly Fixed	50
R31600 - NUCLEAR OPERNS SUPPT	200601	Exempt Regular	Bi-weekly Fixed	20
	200601	Non-Exempt	Bi-weekly Fixed	1
	200602	Exempt Regular	Bi-weekly Fixed	20
	200602	Non-Exempt	Bi-weekly Fixed	1
	200603	Exempt Regular	Bi-weekly Fixed	19
	200603	Non-Exempt	Bi-weekly Fixed	1
	200604	Exempt Regular	Bi-weekly Fixed	18
	200604	Non-Exempt	Bi-weekly Fixed	1
	200605	Exempt Regular	Bi-weekly Fixed	17
	200605	Non-Exempt	Bi-weekly Fixed	1
	200606	Exempt Regular	Bi-weekly Fixed	16
	200606	Non-Exempt	Bi-weekly Fixed	1
	200607	Exempt Regular	Bi-weekly Fixed	17
	200607	Non-Exempt	Bi-weekly Fixed	1
	200608	Exempt Regular	Bi-weekly Fixed	16
	200608	Non-Exempt	Bi-weekly Fixed	1
	200609	Exempt Regular	Bi-weekly Fixed	17
	200609	Non-Exempt	Bi-weekly Fixed	1
	200610	Exempt Regular	Bi-weekly Fixed	18
	200610	Non-Exempt	Bi-weekly Fixed	1
	200611	Exempt Regular	Bi-weekly Fixed	18
	200611	Non-Exempt	Bi-weekly Fixed	1
	200612	Exempt Regular	Bi-weekly Fixed	18
	200612	Non-Exempt	Bi-weekly Fixed	2
R64525 - VP TECH SERVICES	200601	Exempt Regular	Bi-weekly Fixed	100
	200601	Non-Exempt	Bi-weekly Fixed	10

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BRC Description	Ledger Date	Emp.Type	Emp.Status	Actual
	200602	Exempt Regular	Bi-weekly Fixed	99
	200602	Non-Exempt	Bi-weekly Fixed	10
	200603	Exempt Regular	Bi-weekly Fixed	104
	200603	Non-Exempt	Bi-weekly Fixed	10
	200604	Exempt Regular	Bi-weekly Fixed	106
	200604	Non-Exempt	Bi-weekly Fixed	10
	200605	Exempt Regular	Bi-weekly Fixed	106
	200605	Non-Exempt	Bi-weekly Fixed	10
	200606	Exempt Regular	Bi-weekly Fixed	105
	200606	Non-Exempt	Bi-weekly Fixed	10
	200607	Exempt Regular	Bi-weekly Fixed	106
	200607	Non-Exempt	Bi-weekly Fixed	9
	200608	Exempt Regular	Bi-weekly Fixed	107
	200608	Non-Exempt	Bi-weekly Fixed	9
	200609	Exempt Regular	Bi-weekly Fixed	106
	200609	Non-Exempt	Bi-weekly Fixed	8
	200610	Exempt Regular	Bi-weekly Fixed	106
	200610	Non-Exempt	Bi-weekly Fixed	8
	200611	Exempt Regular	Bi-weekly Fixed	106
	200611	Non-Exempt	Bi-weekly Fixed	8
	200612	Exempt Regular	Bi-weekly Fixed	104
	200612	Non-Exempt	Bi-weekly Fixed	8
R64725 - VP PLANT SUPPORT	200601	Exempt Regular	Bi-weekly Fixed	27
	200601	Non-Exempt	Bi-weekly Fixed	3
	200602	Exempt Regular	Bi-weekly Fixed	27
	200602	Non-Exempt	Bi-weekly Fixed	3
	200603	Exempt Regular	Bi-weekly Fixed	27
	200603	Non-Exempt	Bi-weekly Fixed	3
	200604	Exempt Regular	Bi-weekly Fixed	26
	200604	Non-Exempt	Bi-weekly Fixed	3
	200605	Exempt Regular	Bi-weekly Fixed	27
	200605	Non-Exempt	Bi-weekly Fixed	3
	200606	Exempt Regular	Bi-weekly Fixed	30
	200606	Non-Exempt	Bi-weekly Fixed	3
	200607	Exempt Regular	Bi-weekly Fixed	28
	200607	Non-Exempt	Bi-weekly Fixed	3
	200608	Exempt Regular	Bi-weekly Fixed	29
	200608	Non-Exempt	Bi-weekly Fixed	3
	200609	Exempt Regular	Bi-weekly Fixed	28
	200609	Non-Exempt	Bi-weekly Fixed	3
	200610	Exempt Regular	Bi-weekly Fixed	29
	200610	Non-Exempt	Bi-weekly Fixed	3
	200611	Exempt Regular	Bi-weekly Fixed	29
	200611	Non-Exempt	Bi-weekly Fixed	3
	200612	Exempt Regular	Bi-weekly Fixed	28

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BRC Description		Ledger Date	Emp.Type	Emp.Status	Actual
		200612	Non-Exempt	Bi-weekly Fixed	3
R65200 - VP SAFETY ASSURANCE		200601	Exempt Regular	Bi-weekly Fixed	69
		200601	Non-Exempt	Bi-weekly Fixed	6
		200602	Exempt Regular	Bi-weekly Fixed	70
		200602	Non-Exempt	Bi-weekly Fixed	6
		200603	Exempt Regular	Bi-weekly Fixed	72
		200603	Non-Exempt	Bi-weekly Fixed	6
		200604	Exempt Regular	Bi-weekly Fixed	72
		200604	Non-Exempt	Bi-weekly Fixed	6
		200605	Exempt Regular	Bi-weekly Fixed	71
		200605	Non-Exempt	Bi-weekly Fixed	6
		200606	Exempt Regular	Bi-weekly Fixed	72
		200606	Non-Exempt	Bi-weekly Fixed	6
		200607	Exempt Executive	Bi-weekly Fixed	1
		200607	Exempt Regular	Bi-weekly Fixed	70
		200607	Non-Exempt	Bi-weekly Fixed	6
		200608	Exempt Executive	Bi-weekly Fixed	1
		200608	Exempt Regular	Bi-weekly Fixed	70
		200608	Non-Exempt	Bi-weekly Fixed	6
		200609	Exempt Executive	Bi-weekly Fixed	1
		200609	Exempt Regular	Bi-weekly Fixed	71
		200609	Non-Exempt	Bi-weekly Fixed	6
		200610	Exempt Executive	Bi-weekly Fixed	1
		200610	Exempt Regular	Bi-weekly Fixed	71
		200610	Non-Exempt	Bi-weekly Fixed	5
		200611	Exempt Executive	Bi-weekly Fixed	1
		200611	Exempt Regular	Bi-weekly Fixed	72
		200611	Non-Exempt	Bi-weekly Fixed	5
		200612	Exempt Executive	Bi-weekly Fixed	1
		200612	Exempt Regular	Bi-weekly Fixed	73
	1689.5	200612	Non-Exempt	Bi-weekly Fixed	6

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Manpower Trend Report

BASA	
EAC	
Key Figures	
BRC	

Fiscal Year Variant	Calendar year, 4 spec. periods
BRC	NUC DIV BUS UNIT
EAC	FPL EMPLOYEES
Exp	SUSPENSE

Fiscal year/period	

	BRC	EAC\Fiscal year/period	001/2007	002/2007
Actual version	△ ▷ R01044 ENGINEERING SUPPORT SERVICES	FEX-FPL Exempt Employees	51.0	53.0
		FNX-FPL Non-Exempt Employees	3.0	3.0
		Result	54.0	56.0
	▷ R01905 ST. LUCIE PLANT	FBF-FPL Bargaining Unit - Fixed Employees	270.0	268.0
		FBV-FPL Bargaining Unit - Variable Employees		
		FEX-FPL Exempt Employees	373.0	372.0
		FNX-FPL Non-Exempt Employees	46.5	46.5
		Result	689.5	686.5
	▷ R01908 PTN STATION	FBF-FPL Bargaining Unit - Fixed Employees	294.0	292.0
		FBV-FPL Bargaining Unit - Variable Employees		
		FEX-FPL Exempt Employees	360.5	361.5
		FNX-FPL Non-Exempt Employees	49.0	52.0
		Result	703.5	705.5
	▷	FEX-FPL Exempt Employees	18.0	17.0
		FNX-FPL Non-Exempt Employees	2.0	2.0
	▷ R31800 ND MANAGEMENT	Result	20.0	19.0
	▷	FEX-FPL Exempt Employees	105.0	104.0
		FNX-FPL Non-Exempt Employees	9.0	9.0
		Result	114.0	113.0
	▷ R64725 VP PLANT SUPPORT	FEX-FPL Exempt Employees	28.0	27.0
		FNX-FPL Non-Exempt Employees	3.0	3.0
		Result	31.0	30.0
	▷ R65200 VP SAFETY ASSURANCE	FEX-FPL Exempt Employees	72.0	73.0
		FNX-FPL Non-Exempt Employees	6.0	7.0
		Result	78.0	80.0
	△ R31000 NUCLEAR DIVISION BUSINESS UNIT	Result	1,690.0	1,690.0

2007 -2008 -2009 Actual

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Manpower Trend Report

BASA	
EAC	
Key Figures	
BRC	

Fiscal Year Variant	Calendar year, 4 spec. periods
BRC	NUC DIV BUS UNIT
EAC	FPL EMPLOYEES
Exp	SUSPENSE

Fiscal year/period	

	BRC	003/2007	004/2007	005/2007	006/2007	007/2007	008/2007
Actual version	△ ▷ R01044 ENGINEERING SUPPORT SERVICES	56.0	56.0	57.0	59.0	57.0	56.0
		2.0	3.0	3.0	3.0	3.0	3.0
		58.0	59.0	60.0	62.0	60.0	59.0
	▷ R01905 ST. LUCIE PLANT	271.0	273.0	273.0	278.0	285.0	284.0
		371.0	377.0	377.0	378.0	383.0	380.0
		46.5	45.5	44.0	44.0	44.0	44.0
		688.5	696.5	694.0	701.0	[illegible]	708.0
	▷ R01908 PTN STATION	287.0	271.0	277.0	284.0	290.0	288.0
		380.5	359.5	385.5	370.5	371.5	367.5
		53.0	53.0	51.0	51.0	52.0	52.0
		[illegible]	[illegible]	683.5	705.5	713.5	[illegible]
	▷	17.0	15.0	15.0	13.0	14.0	14.0
		2.0	2.0	2.0	2.0	3.0	3.0
	▷ R31800 ND MANAGEMENT	19.0	17.0	[illegible]	15.0	17.0	[illegible]
	▷	104.0	105.0	111.0	112.0	112.0	104.0
		9.0	8.0	9.0	9.0	9.0	8.0
		113.0	113.0	120.0	124.0	[illegible]	112.0
	▷ R64725 VP PLANT SUPPORT	28.0	32.0	32.0	32.0	35.0	45.0
		3.0	4.0	4.0	4.0	6.0	5.0
		31.0	36.0	36.0	36.0	[illegible]	50.0
	▷ R65200 VP SAFETY ASSURANCE	73.0	72.0	72.0	73.0	74.0	75.0
		7.0	7.0	7.0	7.0	7.0	8.0
		80.0	79.0	79.0	80.0	[illegible]	83.0
	△ R31000 NUCLEAR DIVISION BUSINESS UNIT	1,680.0	1,663.0	1,698.5	1,720.5	1,744.5	1,737.5

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Manpower Trend Report

BASA	
EAC	
Key Figures	
BRC	

Fiscal Year Variant	Calendar year, 4 spec. periods
BRC	NUC DIV BUS UNIT
EAC	FPL EMPLOYEES
Exp	SUSPENSE

Fiscal year/period	

	BRC	008/2007	010/2007	011/2007	012/2007	001/2008	002/2008
Actual version	△ ▷ R01044 ENGINEERING SUPPORT SERVICES	54.0	55.0	59.0	59.0	59.0	59.0
		3.0	3.0	3.0	3.0	3.0	3.0
		57.0	58.0	62.0	62.0	[illegible]	62.0
	▷ R01905 ST. LUCIE PLANT	289.0	290.0	290.0	289.0	285.0	284.0
		381.0	380.0	378.0	377.0	369.0	368.0
		45.0	45.0	45.0	45.0	44.0	43.0
		715.0	715.0	713.0	711.0	[illegible]	695.0
	▷ R01908 PTN STATION	294.0	296.0	292.0	291.0	290.0	290.0
		372.5	372.5	378.5	379.5	388.5	387.5
		51.0	51.0	51.0	52.0	51.0	51.0
		[illegible]	[illegible]	721.5	[illegible]	729.5	728.5
	▷	14.0	15.0	15.0	16.0	17.0	17.0
		3.0	2.0	2.0	3.0	4.0	4.0
	▷ R31800 ND MANAGEMENT	17.0	[illegible]	17.0	19.0	21.0	21.0
	▷	104.0	107.0	107.0	110.0	110.0	112.0
		8.0	8.0	8.0	8.0	7.0	7.0
		[illegible]	115.0	115.0	118.0	117.0	[illegible]
	▷ R64725 VP PLANT SUPPORT	45.0	48.0	48.0	47.0	47.0	48.0
		6.0	8.0	6.0	6.0	6.0	6.0
		51.0	54.0	54.0	53.0	53.0	54.0
	▷ R65200 VP SAFETY ASSURANCE	73.0	73.0	73.0	74.0	78.0	78.0
		8.0	10.0	9.0	9.0	10.0	10.0
		81.0	83.0	82.0	83.0	[illegible]	[illegible]
	△ R31000 NUCLEAR DIVISION BUSINESS UNIT	1,750.5	1,761.5	1,764.5	[illegible]	1,768.5	[illegible]

2007 -2008 -2009 Actual

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Manpower Trend Report

BASA	
EAC	
Key Figures	
BRC	

Fiscal Year Variant	Calendar year, 4 spec. periods
BRC	NUC DIV BUS UNIT
EAC	FPL EMPLOYEES
Exp	SUSPENSE

Fiscal year/period	

	BRC	003/2008	004/2008	005/2008	006/2008	007/2008	008/2008
Actual version	△ ▷ R01044 ENGINEERING SUPPORT SERVICES	59.0	59.0	60.0	59.0	51.0	49.0
		3.0	3.0	3.0	3.0	3.0	3.0
		62.0	62.0	63.0	62.0	54.0	52.0
	▷ R01905 ST. LUCIE PLANT	282.0	297.0	309.0	312.0	316.0	318.0
		367.0	365.0	361.0	362.0	386.0	367.0
		43.0	39.0	40.0	41.0	42.0	43.0
		692.0	701.0	710.0	715.0	724.0	[illegible]
	▷ R01906 PTN STATION	298.0	302.0	307.0	308.0	305.0	304.0
		383.5	387.5	389.5	385.5	388.5	392.5
		50.0	50.0	51.0	50.0	51.0	49.0
		731.5	739.5	747.5	743.5	[illegible]	[illegible]
	▷	18.0	19.0	20.0	21.0	24.0	25.0
		4.0	5.0	5.0	5.0	5.0	4.0
	▷ R31800 ND MANAGEMENT	22.0	24.0	[illegible]	26.0	[illegible]	29.0
	▷	118.0	122.0	128.5	128.5	136.5	136.5
		7.0	7.0	7.0	7.0	7.0	7.0
		[illegible]	129.0	135.5	135.5	143.5	[illegible]
	▷ R64725 VP PLANT SUPPORT	52.0	51.0	57.0	65.0	64.0	64.0
		7.0	8.0	8.0	7.0	7.0	8.0
		59.0	59.0	65.0	72.0	[illegible]	72.0
	▷ R65200 VP SAFETY ASSURANCE	80.0	80.0	81.0	76.0	76.0	79.0
		11.0	11.0	10.0	10.0	9.0	9.0
		91.0	91.0	91.0	[illegible]	85.0	89.0
	△ R31000 NUCLEAR DIVISION BUSINESS UNIT	[illegible]	1,805.5	1,837.0	1,840.0	[illegible]	[illegible]

2009 Budget

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Version	C01	Original Budget
Fiscal year	2009	K4/2009
Exp	0	SUSPENSE

BRC		EAC	BASA		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total [illegible]	BRC	Total	EAC Total	BASA	1,983.5	1,982.3	[illegible]	1,987.1	2,003.5	2,044.5	2,097.5	2,008.5	[illegible]	[illegible]	[illegible]	2,761.5
[illegible] SUPERVISION	064314	Total	EAC Total	BASA	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
CSR/MGMT SUPERVISION	064314	FEX-FPL Exempt Employees	FEX CSR/MGMT SUPV	11900910748	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
CSR/MGMT SUPERVISION	064314	FNX-FPL Non-Exempt Employees	FNX CSR/MGMT SUPV	11900910748	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	2.0	3.0
C&I CHIEFS	064515	Total	EAC Total	BASA	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	[illegible]	21.0	21.0	21.0
C&I CHIEFS	064515	FEX-FPL Exempt Employees	FEX CHIEFS REGULATORY	11810021353	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
CODES & INSPECTIONS	064517	Total	EAC Total	BASA	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
CODES & INSPECTIONS	064517	FEX-FPL Exempt Employees	FEX CODES AND INSPECTION	10904922103	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
MATERIALS & COMPONENT	064518	Total	EAC Total	BASA	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	[illegible]	7.0	[illegible]	7.0
MATERIALS & COMPONEN	064518	FEX-FPL Exempt Employees	FEX MATERIALS AND COMPON	11808916781	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
RRAG SUMMARY	064529	Total	EAC Total	BASA	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	[illegible]	[illegible]	[illegible]	7.0
RRAG SUMMARY	064526	FEX-FPL Exempt Employees	FEX RRAG	12146090050	5.0	5.0	5.0	5.0	6.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
RRAG SUMMARY	064529	FEX-FPL Exempt Employees	FEX AFFILIATE DIRECT CHA	12146AFFLDC	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
PLANT MANAGEMENT	092308	Total	EAC Total	BASA	574.0	574.0	574.0	574.0	574.0	574.0	574.0	574.0	[illegible]	[illegible]	[illegible]	574.0
PLANT MANAGEMENT	092300	FBV-FPL Bargaining Unit - Variable Empl	FBV PAYROLL EMPLOYEE REL	01428000000	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0
PLANT MANAGEMENT	092050	FEX-FPL Exempt Employees	FEA EQUIPMENT RELIABILIT	00036000000	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
PLANT MANAGEMENT	092300	FEX-FPL Exempt Employees	FEX PAYROLL EMPLOYEE REL	01428000000	207.0	207.0	207.0	207.0	207.0	207.0	207.0	207.0	207.0	207.0	207.0	207.0
PLANT MANAGEMENT	092080	FNX-FPL Non-Exempt Employees	FNX PAYROLL EMPLOYEE REL	01428000000	36.0	36.0	36.0	36.0	36.0	35.0	36.0	36.0	36.0	36.0	36.0	36.0
PSL ENGINEERING SUMM	064313	Total	EAC Total	BASA	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	[illegible]	118.0	118.0	118.0
PSL ENGINEERING SUMM	064649	FEX-FPL Exempt Employees	FEX REQUESTS FOR ENG. AS	11242000000	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	112.0	113.0	113.0	113.0
PSL ENGINEERING SUMM	064E??	FNX-FPL Non-Exempt Employees	FNX REQUESTS FOR ENG. AS	11242000000	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	6.0	5.0	5.0	5.0
PTN ENGINEERING SUMM	084568	Total	EAC Total	BASA	144.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	[illegible]	146.0	146.0	146.0
PTN ENGINEERING SUMM	084563	FEX-FPL Exempt Employees	FEX PTN ENGRG PAYROLL	12356605800	134.0	136.0	136.0	136.0	136.0	136.0	136.0	136.0	136.0	136.0	136.0	136.0
PTN ENGINEERING SUMM	094680	FNX-FPL Non-Exempt Employees	FNX PTN ENGRG PAYROLL	12356975392	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
MANAGEMENT	091406	Total	EAC Total	BASA	577.0	590.0	[illegible]	603.0	613.0	614.0	616.0	617.0	[illegible]	[illegible]	619.0	620.0
MANAGEMENT	091403	FBV-FPL Bargaining Unit - Variable Empl	FBV PAYROLL	01478928029	317.0	327.0	338.0	344.0	350.0	351.0	353.0	354.0	354.0	355.0	356.0	357.0
MANAGEMENT	091405	FEX-FPL Exempt Employees	FEX PAYROLL	01428928029	221.0	223.0	223.0	223.0	223.0	223.0	223.0	223.0	223.0	223.0	221.0	223.0
MANAGEMENT	091400	FNX-FPL Non-Exempt Employees	FNX PAYROLL	01428938029	39.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
PTN RTE PEOPLE	091457	Total	EAC Total	BASA	9.5	[illegible]	[illegible]	[illegible]	9.5	9.5	[illegible]	[illegible]	9.5	9.5	9.5	9.5
PTN RTE PEOPLE	091457	FEX-FPL Exempt Employees	FEX ADDITIONAL PERSONNEL	0175ADDPER	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
PTN RTE PLANT	091459	Total	EAC Total	BASA	[illegible]	0.0	[illegible]	[illegible]	0.0	0.0	0.0	0.0	0.0	0.0	[illegible]	0.0
PTN RTE PLANT	091459	FEX-FPL Exempt Employees	FEX RTE STAFF	0176RTESTF	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BUSINESS OPERATIONS	095109	Total	EAC Total	BASA	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
BUSINESS OPERATIONS	095109	FEX-FPL Exempt Employees	FEX ST PAYROLL AND OTHER	01420923407	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
BUSINESS OPERATIONS	095109	FNX-FPL Non-Exempt Employees	FNX ST PAYROLL AND OTHER	01420923407	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NUCLEAR OPERATIONS	081700	Total	EAC Total	BASA	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
NUCLEAR OPERATIONS	081700	FNX-FPL Non-Exempt Employees	FNX ST PAYROLL AND OTHER	01420923407	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
PTN FUELS	086641	Total	EAC Total	BASA	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
PTN FUELS	086641	FEX-FPL Exempt Employees	FEX NUCLEAR FUEL PLANT S	12132000040	8.1	8.1	9.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
PTN FUELS	086641	FEX-FPL Exempt Employees	FEX AFFILIATE DIRECT CHA	121324FRDC	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
FUEL PROJECTS	086544	Total	EAC Total	BASA	9.0	9.0	[illegible]	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
FUEL PROJECTS	086544	FEX-FPL Exempt Employees	FEX NUCLEAR FUEL PLANT S	12132000050	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5

2009 Budget

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Version	092	Original Budget
Fiscal year	2008	K42005
Exp	C	SUBFEXSP

BRC		EAC		BASA		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
FUEL PROJECTS	065044	FEX-FPL Exempt Employees	FEX	AFFILIATE DIRECT CHA	12102AFFLDC	4.6	4.5	4.5	4.5	4.6	4.5	4.8	4.5	4.8	4.6	4.5	4.5
[illegible]	064150	Total	EAC	Total	BASA	[illegible]	30.0	30.0	[illegible]	[illegible]	30.0	[illegible]	30.0	30.0	30.0	30.0	30.0
JB PROJECTS BASE	064850	FEX-FPL Exempt Employees	FEX	JUNO NON PROJECT EXP	01470JUNONP	26.0	27.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0
JB PROJECTS BASE	064950	FNX-FPL Non-Exempt Employees	FNX	JUNO NON PROJECT EXP	01470JUNONP	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
PSL PROJECTS BASE	064451	Total	EAC	Total	BASA	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	[illegible]	18.0	[illegible]	18.0
PSL PROJECTS BASE	034451	FEX-FPL Exempt Employees	FEX	PSL PROJECT NON PROJ	01470PSLNPE	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
PTN PROJECTS BASE	064852	Total	EAC	Total	BASA	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	[illegible]	[illegible]	16.0	16.0
PTN PROJECTS BASE	034852	FEX-FPL Exempt Employees	FEX	PTN NON PROJECT EXPE	01470PTNNPE	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
PROJECTS ENGINE BASE	064602	Total	EAC	Total	BASA	40.0	40.0	40.0	40.0	40.0	40.0	[illegible]	40.0	[illegible]	[illegible]	40.0	40.0
PROJECTS ENGINE BASE	064602	FEX-FPL Exempt Employees	FEX	MAJOR PROJ ENG GRP -	12245NPEGRP	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
EPU PROJECT	064730	Total	EAC	Total	BASA	59.5	59.5	60.5	59.5	60.5	60.5	61.5	61.5	[illegible]	61.5	[illegible]	61.5
EPU PROJECT	065730	FEX-FPL Exempt Employees	FEX	PAYROLL EMPLOYEES REL	01420090000	59.5	59.5	59.5	59.5	60.5	60.5	61.5	61.5	61.5	61.5	61.5	61.5
VP PLANT SUPPORT	064728	Total	EAC	Total	BASA	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	[illegible]	79.0	79.0	79.0
VP PLANT SUPPORT	064720	FEX-FPL Exempt Employees	FEX	ST PAYROLL AND OTHER	01420923407	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0	48.0
VP PLANT SUPPORT	064785	FEX-FPL Exempt Employees	FEX	CAPACITY SECURITY PA	01514920989	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
VP PLANT SUPPORT	064729	FNX-FPL Non-Exempt Employees	FNX	ST PAYROLL AND OTHER	01420923407	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
VP PLANT SUPPORT	064725	FNX-FPL Non-Exempt Employees	FNX	CAPACITY SECURITY PA	01514920920	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
JOAUB MANAGEMENT	064345	Total	EAC	Total	BASA	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	[illegible]	[illegible]	[illegible]	23.0
JOAUB MANAGEMENT	064345	FEX-FPL Exempt Employees	FEX	OFFICE FURNITURE, FI	00091000000	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
JOAUB MANAGEMENT	064345	FEX-FPL Exempt Employees	FEX	SYSTEMS AND AUDITS -	10136000000	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
JOAUB MANAGEMENT	064345	FEX-FPL Exempt Employees	FEX	JOAUB MANAGEMENT AU	10140500000	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
JOAUB MANAGEMENT	064345	FEX-FPL Exempt Employees	FEX	VENDOR ACTIVITIES -	10622000000	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
JOAUB MANAGEMENT	064345	FNX-FPL Non-Exempt Employees	FNX	SYSTEMS AND AUDITS -	10136000000	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
JOAUB MANAGEMENT	064345	FNX-FPL Non-Exempt Employees	FNX	VENDOR ACTIVITIES -	10622000000	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
NUCL ASSURANCE-CNRB	069554	Total	EAC	Total	BASA	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	[illegible]	[illegible]	[illegible]	2.0
NUCL ASSURANCE-CNRB	069554	FEX-FPL Exempt Employees	FEX	COMPANY NUCLEAR REVI	10137000000	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
PSL-NUC ASSURANCE	067500	Total	EAC	Total	BASA	19.0	19.0	19.0	19.0	19.0	19.0	[illegible]	[illegible]	19.0	[illegible]	19.0	19.0
PSL-NUC ASSURANCE	067500	FEX-FPL Exempt Employees	FEX	JOAPSL MANAGEMENT A	10524500000	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
PSL-NUC ASSURANCE	067500	FNX-FPL Non-Exempt Employees	FNX	JOAPSL MANAGEMENT A	10524500000	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
PTN-NUC ASSURANCE	069400	Total	EAC	Total	BASA	18.0	[illegible]	[illegible]	[illegible]	18.0	18.0	18.0	18.0	[illegible]	18.0	18.0	18.0
PTN-NUC ASSURANCE	069400	FEX-FPL Exempt Employees	FEX	QUALITY SUPPORT-JNA	11507000000	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0
PTN-NUC ASSURANCE	069450	FNX-FPL Non-Exempt Employees	FNX	QUALITY SUPPORT-JNA	11507000000	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
NUCLR ASSURANCE CNRB	069575	Total	EAC	Total	BASA	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
NUCLR ASSURANCE CNRB	059575	FEX-FPL Exempt Employees	FEX	EMPLOYEE CONCERNS PR	01672000000	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
NUCLR ASSURANCE CNRB	069558	FEX-FPL Exempt Employees	FEX	EMPLOYEE CONCERNS PR	01673000000	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NUCLR ASSURANCE CNRB	069555	FEX-FPL Exempt Employees	FEX	EMPLOYEE CONCERNS PR	01674000000	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
SAFETY ASSURE MGT	065225	Total	EAC	Total	BASA	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0	156.0
SAFETY ASSURE MGT	065225	FEX-FPL Exempt Employees	FEX	ST PAYROLL AND OTHER	01420923407	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0
SAFETY ASSURE MGT	065225	FNX-FPL Non-Exempt Employees	FNX	ST PAYROLL AND OTHER	01420923407	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0

2010 Budget

Florida Power & Light Company
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Version	042	Original Budget
Fiscal year	2010	K07018
Era	4	SUSPENSE

BRC		EAC		BASA		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
[illegible]	BRC	Total	EAC	Total	BASA	2,032.8	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2,047.8	[illegible]	2,056.0	[illegible]	[illegible]	[illegible]
CMMDNT SUPERVISION	[illegible]	Total	EAC	Total	BASA	10.0	10.0	10.0	10.0	10.0	[illegible]	[illegible]	10.0	10.0	10.0	10.0	10.0
CMMDNT SUPERVISION	064514	FEX-FPL Exempt Employees	FEX	CMMDNT SUPV	1155091C745	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
CMMDNT SUPERVISION	094514	FNX-FPL Non-Exempt Employees	FNX	CMMDNT SUPV	1156D9307C6	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
GSI CHIEFS	[illegible]	Total	EAC	Total	BASA	21.0	[illegible]	21.0	[illegible]	21.0	21.0	[illegible]	21.0	21.0	21.0	[illegible]	21.0
GSI CHIEFS	064515	FEX-FPL Exempt Employees	FEX	CHIEFS REGULATORY	1158992133D	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
CODES & INSPECTIONS	[illegible]	Total	EAC	Total	BASA	9.0	[illegible]	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	[illegible]	9.0
CODES & INSPECTIONS	064517	FEX-FPL Exempt Employees	FEX	CODES AND INSPECTION	1099452D2143	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
MATERIALS & COMPONENT	064518	Total	EAC	Total	BASA	7.0	7.0	7.0	7.0	7.0	7.0	7.0	[illegible]	7.0	7.0	[illegible]	7.0
MATERIALS & COMPONEN	064518	FEX-FPL Exempt Employees	FEX	MATERIALS AND COMPON	1188B312751	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
RRAG SUMMARY	[illegible]	Total	EAC	Total	BASA	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	[illegible]	7.0
RRAG SUMMARY	064725	FEX-FPL Exempt Employees	FEX	RRAG	121418000800	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
RRAG SUMMARY	064529	FEX-FPL Exempt Employees	FEX	AFFILIATE DIRECT CHA	121453FFLDC	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
PLANT MANAGEMENT	[illegible]	Total	EAC	Total	BASA	587.0	587.0	587.0	587.0	587.0	587.0	587.0	587.0	587.0	587.0	[illegible]	587.0
PLANT MANAGEMENT	032900	FBV-FPL Bargaining Unit - Variable Emplo	FBV	PAYROLL EMPLOYEE REL	0142200700D	337.0	337.0	337.0	337.0	337.0	337.0	337.0	337.0	337.0	337.0	337.0	337.0
PLANT MANAGEMENT	092900	FEX-FPL Exempt Employees	FEX	PAYROLL EMPLOYEE REL	0142R00D600	214.0	214.0	214.0	214.0	214.0	214.0	214.0	214.0	214.0	214.0	214.0	214.0
PLANT MANAGEMENT	092900	FNX-FPL Non-Exempt Employees	FNX	PAYROLL EMPLOYEE REL	0142500D072	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
PSL ENGINEERING SUBM	[illegible]	Total	EAC	Total	BASA	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	[illegible]	[illegible]	118.0
PSL ENGINEERING SUBM	064369	FEX-FPL Exempt Employees	FEX	REQUESTS FOR ENG. AS	1124200000D	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0
PSL ENGINEERING SUBM	064369	FNX-FPL Non-Exempt Employees	FNX	REQUESTS FOR ENG. AS	1124200040D	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
PTN ENGINEERING SUBM	[illegible]	Total	EAC	Total	BASA	148.0	[illegible]	[illegible]	148.0	148.0	148.0	148.0	[illegible]	148.0	148.0	[illegible]	148.0
PTN ENGINEERING SUBM	064508	FEX-FPL Exempt Employees	FEX	PTN ENGRG PAYROLL	1235805800	138.0	138.0	138.0	138.0	138.0	138.0	138.0	138.0	138.0	138.0	138.0	138.0
PTN ENGINEERING SUBM	064408	FNX-FPL Non-Exempt Employees	FNX	PTN ENGRG PAYROLL	1250805800	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
MANAGEMENT	[illegible]	Total	EAC	Total	BASA	[illegible]	[illegible]	[illegible]	447.0	445.0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
MANAGEMENT	081400	FBV-FPL Bargaining Unit - Variable Emplo	FBV	PAYROLL	01428977R08	380.0	368.0	374.0	376.0	377.0	379.0	380.0	382.0	383.0	385.0	387.0	387.0
MANAGEMENT	081400	FEX-FPL Exempt Employees	FEX	PAYROLL	0142B025028	228.0	228.0	230.0	231.0	232.0	272.0	233.0	234.0	234.0	234.0	235.0	235.0
MANAGEMENT	061400	FNX-FPL Non-Exempt Employees	FNX	PAYROLL	0142B5C5029	37.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
PTN RTS PEOPLE	[illegible]	Total	EAC	Total	BASA	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PTN RTS PEOPLE	061407	FEX-FPL Exempt Employees	FEX	ADDITIONAL PERSONNEL	0175ADDPER	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
BUSINESS OPERATIONS	[illegible]	Total	EAC	Total	BASA	15.0	15.0	[illegible]	15.0	15.0	15.0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	15.0
BUSINESS OPERATIONS	035100	FEX-FPL Exempt Employees	FEX	ST PAYROLL AND OTHER	0142B023407	13.0	13.0	12.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
BUSINESS OPERATIONS	065100	FNX-FPL Non-Exempt Employees	FNX	ST PAYROLL AND OTHER	0142B023407	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NUCLEAR OPERATIONS	[illegible]	Total	EAC	Total	BASA	1.0	[illegible]	[illegible]	[illegible]	[illegible]	1.0	[illegible]	1.0	1.0	1.0	1.0	1.0
NUCLEAR OPERATIONS	061700	FNX-FPL Non-Exempt Employees	FNX	ST PAYROLL AND OTHER	0142B023407	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
PTN FUELS	[illegible]	Total	EAC	Total	BASA	13.0	[illegible]	13.0	13.0	13.0	[illegible]	[illegible]	13.0	[illegible]	13.0	13.0	13.0
PTN FUELS	064841	FEX-FPL Exempt Employees	FEX	NUCLEAR FUEL PLANT S	12152200000	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
PTN FUELS	069341	FEX-FPL Exempt Employees	FEX	AFFILIATE DIRECT CHA	12152AFFLDC	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
FUEL PROJECTS	[illegible]	Total	EAC	Total	BASA	9.0	[illegible]	[illegible]	9.0	9.0	9.0	9.0	9.0	9.0	[illegible]	9.0	9.0
FUEL PROJECTS	065344	FEX-FPL Exempt Employees	FEX	NUCLEAR FUEL PLANT S	12132000000	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
FUEL PROJECTS	075844	FEX-FPL Exempt Employees	FEX	AFFILIATE DIRECT CHA	12132AFFLDC	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
JB PROJECTS BASE	[illegible]	Total	EAC	Total	BASA	30.0	30.0	30.0	30.0	30.0	30.0	[illegible]	[illegible]	30.0	[illegible]	30.0	[illegible]
JB PROJECTS BASE	064450	FEX-FPL Exempt Employees	FEX	JUNO NON PROJECT EXP	0147BJUOIOHP	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0
JB PROJECTS BASE	064650	FNX-FPL Non-Exempt Employees	FNX	JUNO NON PROJECT EXP	0147BJUZIOHP	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
PSL PROJECTS BASE	[illegible]	Total	EAC	Total	BASA	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
PSL PROJECTS BASE	064651	FEX-FPL Exempt Employees	FEX	PSL PROJECT NON PROJ	01472PSLNPE	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	15.0	16.0	16.0	16.0
PTN PROJECTS BASE	[illegible]	Total	EAC	Total	BASA	16.0	[illegible]	[illegible]	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
PTN PROJECTS BASE	064652	FEX-FPL Exempt Employees	FEX	PTN NON PROJECT EXPE	01478PTNNPE	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0

2010 Budget.

Florida Power & Light Company
Docket No. 080677-EI
SFHHA's Tenth Set of Interrogatories
Question No. 291
Attachment No. 1
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Version	003	Original Budget
Fiscal year	2010	[illegible]
Exp	#	[illegible]

BRC		EAC		BASA		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PROJECTS ENGINE BASE	[illegible]	Total	EAC	Total	BASA	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PROJECTS ENGINE BASE	068802	FEX-FPL Exempt Employees	FEX	MAJOR PROJ ENG OFF -	12345MPEGRP	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
EPU PROJECT	068730	Total	EAC	Total	BASA	[illegible]	[illegible]	48.5	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	49.5	49.5	48.5	[illegible]
EPU PROJECT	058730	FEX-FPL Exempt Employees	FEX	PAYROLL EMPLOYEE REL	01427000000	42.5	49.5	48.5	48.5	49.0	49.5	49.5	49.5	49.5	49.5	48.5	49.5
VP PLANT SUPPORT	054725	Total	EAC	Total	BASA	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
VP PLANT SUPPORT	084725	FEX-FPL Exempt Employees	FEX	ST PAYROLL AND OTHER	01420823407	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0
VP PLANT SUPPORT	084725	FEX-FPL Exempt Employees	FEX	CAPACITY SECURITY PA	01814928808	27.0	21.0	27.0	27.0	27.0	27.0	21.0	21.0	21.0	21.0	21.0	21.0
VP PLANT SUPPORT	084725	FNX-FPL Non-Exempt Employees	FNX	ST PAYROLL AND OTHER	01430823407	8.0	5.0	8.0	5.0	5.0	8.0	8.0	5.0	8.0	8.0	8.0	8.0
VP PLANT SUPPORT	054725	FNX-FPL Non-Exempt Employees	FNX	CAPACITY SECURITY PA	01514925800	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
JOAUB MANAGEMENT	064343	Total	EAC	Total	BASA	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	[illegible]	[illegible]	[illegible]
JOAUB MANAGEMENT	064345	FEX-FPL Exempt Employees	FEX	OFFICE FURNITURE, ST	00881000004	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
JOAUB MANAGEMENT	064345	FEX-FPL Exempt Employees	FEX	SYSTEMS AND AUDITS -	10138800000	6.0	6.0	6.0	6.0	6.0	6.0	5.0	6.0	6.0	6.0	6.0	6.0
JOAUB MANAGEMENT	054345	FEX-FPL Exempt Employees	FEX	JOAUB MANAGEMENT AH	10140000000	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
JOAUB MANAGEMENT	064345	FEX-FPL Exempt Employees	FEX	VENDOR ACTIVITIES -	10622000000	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
JOAUB MANAGEMENT	064345	FNX-FPL Non-Exempt Employees	FNX	SYSTEMS AND AUDITS -	10134000000	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
JOAUB MANAGEMENT	054345	FNX-FPL Non-Exempt Employees	FNX	VENDOR ACTIVITIES -	10522000000	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
NUCL ASSURANCE-CNRB	849534	Total	EAC	Total	BASA	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	[illegible]	[illegible]	2.0
NUCL ASSURANCE-CNRB	059534	FEX-FPL Exempt Employees	FEX	COMPANY NUCLEAR REVI	10137000000	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
PSL-NUC ASSURANCE	067600	Total	EAC	Total	BASA	19.0	19.0	19.0	19.0	19.0	19.0	[illegible]	19.0	19.0	[illegible]	[illegible]	[illegible]
PSL-NUC ASSURANCE	087600	FEX-FPL Exempt Employees	FEX	JOAP PSL MANAGEMENT A	10024000000	18.0	18.0	18.0	18.0	18.0	18.0	13.0	18.0	18.0	18.0	18.0	13.0
PSL-NUC ASSURANCE	067600	FNX-FPL Non-Exempt Employees	FNX	JOAP PSL MANAGEMENT A	10034000000	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
PTN-NUC ASSURANCE	069400	Total	EAC	Total	BASA	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	[illegible]	[illegible]	18.0
PTN-NUC ASSURANCE	069400	FEX-FPL Exempt Employees	FEX	QUALITY SUPPORT-PTN	11507000000	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0
PTN-NUC ASSURANCE	059400	FNX-FPL Non-Exempt Employees	FNX	QUALITY SUPPORT-PTN	11507070004	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
NUCLR ASSURANCE CNRB	061385	Total	EAC	Total	BASA	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	[illegible]	[illegible]	[illegible]
NUCLR ASSURANCE CNRB	[illegible]	FEX-FPL Exempt Employees	FEX	EMPLOYEE CONCERNS PR	01672000000	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
NUCLR ASSURANCE CNRB	068857	FEX-FPL Exempt Employees	FEX	EMPLOYEE CONCERNS PR	01673000000	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NUCLR ASSURANCE CNRB	[illegible]	FEX-FPL Exempt Employees	FEX	EMPLOYEE CONCERNS PR	01674000000	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
SAFETY ASSURE MGT	044225	Total	EAC	Total	BASA	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
SAFETY ASSURE MGT	095225	FEX-FPL Exempt Employees	FEX	ST PAYROLL AND OTHER	01428823407	148.0	149.0	145.0	148.0	148.0	143.0	148.0	148.0	148.0	148.0	148.0	148.0
SAFETY ASSURE MGT	098225	FNX-FPL Non-Exempt Employees	FNX	ST PAYROLL AND OTHER	01430823407	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0

2011 Budget

Florida Power & Light Company
Docket No. 080677-EI
SFHHA's Tenth Set of Interrogatories
Question No. 291
Attachment No. 1
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Version	092	Original Budget
Fiscal year	2011	1/4/2011
Exp	6	SUSPENSE

BRC	EAC		BASA		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total [illegible] BRC	FEX Total	EXPS	Total	BASA	2,076.8	[illegible]	2,092.8	2,095.8	2,088.8	[illegible]	[illegible]	[illegible]	2,198.8	2,108.8	[illegible]	[illegible]
CSRMGNT SUPT 064514	Total	EAC	Total	BASA	10.0	10.0	10.0	[illegible]	[illegible]	[illegible]	10.0	10.0	10.0	10.0	10.0	10.0
CSRMGNT SUPT 064514	FEX-FPL Exempt Employees	FEX	CSRMGNT SUPV	11850916748	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
CSRMGNT SUPT 064514	FNX-FPL Non-Exempt Employees	FNX	CSRMGNT SUPV	11850916748	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
CSI CHIEFS 064515	Total	EAC	Total	BASA	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	[illegible]	21.0	21.0
CSI CHIEFS 064515	FEX-FPL Exempt Employees	FEX	CHIEFS REGULATORY	11850921374	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
CODES & INSPE 064517	Total	EAC	Total	BASA	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	[illegible]	[illegible]	9.0
CODES & INSPE 064517	FEX-FPL Exempt Employees	FEX	CODES AND INSPECTION	10984902158	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
MATERIALS & C 064518	Total	EAC	Total	BASA	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	[illegible]	[illegible]	7.0
MATERIALS & C 064518	FEX-FPL Exempt Employees	FEX	MATERIALS AND COMPON	11868816751	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
RRAG SUMMAR 064529	Total	EAC	Total	BASA	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	[illegible]	[illegible]	7.0
RRAG SUMMAR 064529	FEX-FPL Exempt Employees	FEX	RRAG	12140000000	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
RRAG SUMMAR 064529	FEX-FPL Exempt Employees	FEX	AFFILIATE DIRECT CHA	1214AFFLDC	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
PLANT MANAGE 092300	Total	EAC	Total	BASA	595.0	589.0	596.0	596.0	596.0	599.0	596.0	599.0	596.0	[illegible]	[illegible]	[illegible]
PLANT MANAGE 092300	FBV-FPL Bargaining Unit - Variable Emplo	FBV	PAYROLL EMPLOYEE REL	01425000000	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0	341.0
PLANT MANAGE 092300	FEX-FPL Exempt Employees	FEX	PAYROLL EMPLOYEE REL	01425000000	218.0	210.0	219.0	210.0	219.0	218.0	218.0	218.0	218.0	219.0	210.0	210.0
PLANT MANAGE 092300	FNX-FPL Non-Exempt Employees	FNX	PAYROLL EMPLOYEE REL	01425000000	36.0	36.0	36.0	35.0	36.0	35.0	36.0	36.0	35.0	36.0	36.0	36.0
PSL ENGINEERI 064599	Total	EAC	Total	BASA	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	[illegible]	[illegible]	118.0
PSL ENGINEERI 064599	FEX-FPL Exempt Employees	FEX	REQUESTS FOR ENG. AS	11243000000	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	113.0	112.0	113.0
PSL ENGINEERI 064599	FNX-FPL Non-Exempt Employees	FNX	REQUESTS FOR ENG. AS	11242000500	5.0	5.0	5.0	5.0	5.0	5.0	5.0	6.0	5.0	5.0	6.0	5.0
PTN ENGINEERI 064589	Total	EAC	Total	BASA	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	146.0	[illegible]	[illegible]	146.0
PTN ENGINEERI 064589	FEX-FPL Exempt Employees	FEX	PTN ENGRG PAYROLL	12516805100	136.0	136.0	136.0	132.0	136.0	136.0	135.0	136.0	136.0	136.0	136.0	136.0
PTN ENGINEERI 064589	FNX-FPL Non-Exempt Employees	FNX	PTN ENGRG PAYROLL	12506205800	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
MANAGEMENT 091400	Total	EAC	Total	BASA	683.0	670.0	678.0	682.0	683.0	684.0	684.0	686.0	691.0	[illegible]	[illegible]	702.0
MANAGEMENT 091400	FBV-FPL Bargaining Unit - Variable Emplo	FBV	PAYROLL	01425026025	366.0	391.0	398.0	401.0	401.0	403.0	404.0	402.0	410.0	412.0	414.0	416.0
MANAGEMENT 091400	FEX-FPL Exempt Employees	FEX	PAYROLL	01426026025	235.0	229.0	241.0	241.0	242.0	241.0	240.0	240.0	241.0	243.0	245.0	243.0
MANAGEMENT 091400	FNX-FPL Non-Exempt Employees	FNX	PAYROLL	01426026026	40.0	40.0	40.0	40.0	40.0	46.0	40.0	40.0	40.0	40.0	40.0	40.0
PTN RTE PEOPL 091482	Total	EAC	Total	BASA	4.0	4.0	4.0	4.0	4.0	4.0	[illegible]	4.0	[illegible]	[illegible]	[illegible]	4.0
PTN RTE PEOPL 091482	FEX-FPL Exempt Employees	FEX	ADDITIONAL PERSONNEL	0173ADDPER	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
BUSINESS OPE 095100	Total	EAC	Total	BASA	[illegible]	[illegible]	15.0	15.0	[illegible]	15.0	15.0	[illegible]	[illegible]	15.0	15.0	15.0
BUSINESS OPE 095100	FEX-FPL Exempt Employees	FEX	ST PAYROLL AND OTHER	01428823407	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
BUSINESS OPE 095100	FNX-FPL Non-Exempt Employees	FNX	ST PAYROLL AND OTHER	01428823407	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
PTN FUELS 068841	Total	EAC	Total	BASA	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
PTN FUELS 068841	FEX-FPL Exempt Employees	FEX	NUCLEAR FUEL PLANT B	12132000000	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
PTN FUELS 068841	FEX-FPL Exempt Employees	FEX	AFFILIATE DIRECT CHA	12132AFFLDC	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
FUEL PROJECT 068844	Total	EAC	Total	BASA	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
FUEL PROJECT 068844	FEX-FPL Exempt Employees	FEX	NUCLEAR FUEL PLANT B	12132000000	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
FUEL PROJECT 068844	FEX-FPL Exempt Employees	FEX	AFFILIATE DIRECT CHA	12132AFFLDC	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
JB PROJECTS & 094860	Total	EAC	Total	BASA	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
JB PROJECTS & 094860	FEX-FPL Exempt Employees	FEX	JUNO NON PROJECT EXP	01478JUNONP	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0
JB PROJECTS & 094860	FNX-FPL Non-Exempt Employees	FNX	JUNO NON PROJECT EXP	01478JUNONP	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
PSL PROJECTS 094861	Total	EAC	Total	BASA	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0

2011 Budget

Florida Power & Light Company
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Question No. 291
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Version	CV2	Original Budget
Fiscal year	2011	K4/2011
Exp	0	$ UEXPENSE

BRC	EAC		BASA		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PSL PROJECTS 064861	FEX-FPL Exempt Employees	FEX	PSL PROJECT NON PROJ	01476PSLNPE	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
PTN PROJECTS 064862	Total	EAC	Total	BASA	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
PTN PROJECTS 064862	FEX-FPL Exempt Employees	FEX	PTN NON PROJECT EXPE	01478PTNNPE	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
PROJECTS ENG 058802	Total	EAC	Total	BASA	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
PROJECTS ENG 058802	FEX-FPL Exempt Employees	FEX	MAJOR PROJ ENG OFF -	12345MPEGRP	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
EPU PROJECT 068730	Total	EAC	Total	BASA	47.8	47.8	47.8	47.8	47.8	47.8	47.8	47.8	47.8	47.8	47.8	47.8
EPU PROJECT 068730	FEX-FPL Exempt Employees	FEX	PAYROLL EMPLOYEE REL	01428000006	47.8	47.8	47.8	47.8	47.8	47.8	47.8	47.8	47.8	47.8	47.8	47.8
VP PLANT SUPP 064725	Total	EAC	Total	BASA	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0	82.0
VP PLANT SUPP 064725	FEX-FPL Exempt Employees	FEX	ST PAYROLL AND OTHER	01428023407	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
VP PLANT SUPP 064725	FEX-FPL Exempt Employees	FEX	CAPACITY SECURITY PA	01514020208	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
VP PLANT SUPP 064725	FNX-FPL Non-Exempt Employees	FNX	ST PAYROLL AND OTHER	01425023407	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
VP PLANT SUPP 064725	FNX-FPL Non-Exempt Employees	FNX	CAPACITY SECURITY PA	01514020209	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
JOAN/B MANAG 064345	Total	EAC	Total	BASA	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
JOAN/B MANAG 064345	FEX-FPL Exempt Employees	FEX	OFFICE FURNITURE, R	06621000000	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
JOAN/B MANAG 064345	FEX-FPL Exempt Employees	FEX	SYSTEMS AND AUDITS -	10139000009	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
JOAN/B MANAG 064345	FEX-FPL Exempt Employees	FEX	JOAN/B MANAGEMENT AS	10140000009	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
JOAN/B MANAG 064345	FEX-FPL Exempt Employees	FEY	VENDOR ACTIVITIES -	10822000000	7.0	7.0	7.0	7.0	7.0	7.6	7.0	7.0	7.0	7.0	7.0	7.0
JOAN/B MANAG 064345	FNX-FPL Non-Exempt Employees	FNY	SYSTEMS AND AUDITS -	10136000000	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
JOAN/B MANAG 064345	FNX-FPL Non-Exempt Employees	FNX	VENDOR ACTIVITIES -	10822000000	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
NUCL ASSURAN 063554	Total	EAC	Total	BASA	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NUCL ASSURAN 063554	FEX-FPL Exempt Employees	FEX	COMPANY NUCLEAR REVI	10137000000	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
PSL-NUC ASSU 067600	Total	EAC	Total	BASA	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0
PSL-NUC ASSU 067600	FEX-FPL Exempt Employees	FEX	JOA/PSL MANAGEMENT A	10524000050	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
PSL-NUC ASSU 067600	FNX-FPL Non-Exempt Employees	FNX	JOA/PSL MANAGEMENT A	10524000500	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
PTN-NUC ASSU 069400	Total	EAC	Total	BASA	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
PTN-NUC ASSU 069400	FEX-FPL Exempt Employees	FEX	QUALITY SUPPORT-JNA/	11507900600	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0
PTN-NUC ASSU 069400	FNX-FPL Non-Exempt Employees	FNX	QUALITY SUPPORT-JNA/	11507000000	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
NUCLR ASSURA 068565	Total	EAC	Total	BASA	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
NUCLR ASSURA 068565	FEX-FPL Exempt Employees	FEX	EMPLOYEE CONCERNS PR	01672000000	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
NUCLR ASSURA 068565	FEX-FPL Exempt Employees	FEX	EMPLOYEE CONCERNS PR	01673000107	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NUCLR ASSURA 068565	FEX-FPL Exempt Employees	FEX	EMPLOYEE CONCERNS PR	01674000000	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
SAFETY ASSUR 065225	Total	EAC	Total	BASA	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0
SAFETY ASSUR 065225	FEX-FPL Exempt Employees	FEX	ST PAYROLL AND OTHER	01428023407	152.0	152.0	152.0	152.0	152.0	152.0	152.0	152.0	152.0	152.0	152.0	152.0
SAFETY ASSUR 065225	FNX-FPL Non-Exempt Employees	FNX	ST PAYROLL AND OTHER	01428023407	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0

2007 -2008 -2009 Actual

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Manpower Trend Report

BASA	
EAC	
Key Figures	
BRC	

Fiscal Year Variant	Calendar year, 4 spec. periods
BRC	NUC DIV BUS UNIT
EAC	FPL EMPLOYEES
Exp	SUSPENSE

Fiscal year/period	

	BRC	008/2007	009/2007	010/2007	011/2007	012/2007
Actual version	△ ▷ R01044 ENGINEERING SUPPORT SERVICES	56.0	54.0	55.0	59.0	59.0
		3.0	3.0	3.0	3.0	3.0
		59.0	67.0	58.0	62.0	62.0
	▷ R01905 ST. LUCIE PLANT	284.0	289.0	290.0	290.0	289.0
		380.0	381.0	380.0	378.0	377.0
		44.0	45.0	45.0	45.0	45.0
		708.0	715.0	715.0	713.0	711.0
	▷ R01908 PTN STATION	289.0	294.0	296.0	292.0	291.0
		367.5	372.5	372.5	378.5	379.5
		52.0	51.0	51.0	51.0	52.0
		708.5	717.5	719.5	721.5	722.5
	▷	14.0	14.0	15.0	15.0	16.0
		3.0	3.0	2.0	2.0	3.0
	▷ R31800 ND MANAGEMENT	17.0	17.0	17.0	17.0	19.0
	▷	104.0	104.0	107.0	107.0	110.0
		8.0	8.0	8.0	8.0	8.0
		112.0	112.0	115.0	115.0	118.0
	▷ R64725 VP PLANT SUPPORT	45.0	45.0	48.0	48.0	47.0
		5.0	6.0	6.0	6.0	6.0
		50.0	51.0	54.0	54.0	53.0
	▷ R65200 VP SAFETY ASSURANCE	75.0	73.0	73.0	73.0	74.0
		8.0	8.0	10.0	9.0	9.0
		83.0	81.0	83.0	82.0	83.0
	△ R31000 NUCLEAR DIVISION BUSINESS UNIT	1,737.5	1,750.5	1,761.5	1,764.5	1,768.5

2007 -2008 -2009 Actual

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Manpower Trend Report

BASA	
EAC	
Key Figures	
BRC	

Fiscal Year Variant	Calendar year, 4 spec. periods
BRC	NUC DIV BUS UNIT
EAC	FPL EMPLOYEES
Exp	SUSPENSE

Fiscal year/period	

	BRC	001/2008	002/2008	003/2008	004/2008	005/2008
Actual version	△ ▷ R01044 ENGINEERING SUPPORT SERVICES	59.0	59.0	59.0	59.0	60.0
		3.0	3.0	3.0	3.0	3.0
		62.0	62.0	62.0	62.0	63.0
	▷ R01805 ST. LUCIE PLANT	285.0	284.0	282.0	297.0	309.0
		369.0	368.0	387.0	365.0	361.0
		44.0	43.0	43.0	39.0	40.0
		698.0	695.0	692.0	701.0	710.0
	▷ R01908 PTN STATION	290.0	290.0	298.0	302.0	307.0
		388.5	387.5	383.5	387.5	389.5
		51.0	51.0	50.0	50.0	51.0
		729.5	728.5	731.5	739.5	747.5
	▷	17.0	17.0	18.0	19.0	20.0
		4.0	4.0	4.0	5.0	5.0
	▷ R31800 ND MANAGEMENT	21.0	24.0	22.0	24.0	28.0
	▷	110.0	112.0	118.0	122.0	128.5
		7.0	7.0	7.0	7.0	7.0
		117.0	119.0	126.0	129.0	135.5
	▷ R64725 VP PLANT SUPPORT	47.0	48.0	52.0	51.0	57.0
		6.0	6.0	7.0	8.0	8.0
		53.0	54.0	59.0	59.0	65.0
	▷ R65200 VP SAFETY ASSURANCE	78.0	78.0	80.0	80.0	81.0
		10.0	10.0	11.0	11.0	10.0
		88.0	88.0	91.0	91.0	91.0
	△ R31000 NUCLEAR DIVISION BUSINESS UNIT	1,768.5	1,767.5	1,782.5	1,805.5	1,837.0

2007 - 2008 - 2009 Actual

Manpower Trend Report

BASA	
EAC	
Key Figures	
BRC	

Fiscal Year Variant	Calendar year, 4 spec. periods
BRC	NUC DIV BUS UNIT
EAC	FPL EMPLOYEES
Exp	SUSPENSE

Fiscal year/period	

	BRC	006/2008	007/2008	008/2008	009/2008	010/2008
Actual version	△ ▷ R01044 ENGINEERING SUPPORT SERVICES	69.0	51.0	49.0	48.0	47.0
		3.0	3.0	3.0	3.0	3.0
		62.0	54.0	52.0	51.0	50.0
	▷ R01905 ST. LUCIE PLANT	312.0	316.0	318.0	334.0	333.0
		362.0	366.0	367.0	369.0	368.0
		41.0	42.0	43.0	43.0	43.0
		715.0	724.0	728.0	746.0	744.0
	▷ R01908 PTN STATION	308.0	305.0	304.0	307.0	311.0
		385.5	388.5	392.5	402.0	402.0
		50.0	51.0	49.0	51.0	51.0
		743.5	744.5	745.5	760.0	764.0
	▷	21.0	24.0	25.0	28.0	25.0
		5.0	5.0	4.0	4.0	4.0
	▷ R31800 ND MANAGEMENT	26.0	29.0	29.0	29.0	29.0
	▷	128.5	136.5	136.5	140.5	140.5
		7.0	7.0	7.0	7.0	7.0
		136.5	143.5	143.5	147.5	147.5
	▷ R64725 VP PLANT SUPPORT	65.0	64.0	64.0	67.0	67.0
		7.0	7.0	8.0	8.0	8.0
		72.0	71.0	72.0	75.0	75.0
	▷ R65200 VP SAFETY ASSURANCE	76.0	78.0	79.0	81.0	79.0
		10.0	9.0	9.0	9.0	9.0
		86.0	85.0	88.0	90.0	88.0
	△ R31000 NUCLEAR DIVISION BUSINESS UNIT	1,840.0	1,851.0	1,858.0	1,898.5	1,897.5

Florida Power Light Company
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Question No. 291 - Supplemental
Attachment No. 1

2007 -2008 -2009 Actual

Manpower Trend Report

BASA	
EAC	
Key Figures	
BRC	

Fiscal Year Variant	Calendar year, 4 spec. periods
BRC	NUC DIV BUS UNIT
EAC	FPL EMPLOYEES
Exp	SUSPENSE

Fiscal year/period

	BRC	011/2008	012/2008	001/2009	002/2009	003/2009
Actual version	△ ▷ R01044 ENGINEERING SUPPORT SERVICES	47.0	48.0	47.0	47.0	47.0
		3.0	3.0	3.0	2.0	2.0
		50.0	51.0	50.0	49.0	49.0
		333.0	333.0	333.0	332.0	330.0
	▷ R01905 ST. LUCIE PLANT					
		368.0	364.0	364.0	366.0	364.0
		43.0	42.0	42.0	42.0	41.0
		744.0	739.0	739.0	740.0	735.0
		311.0	314.0	315.0	318.0	316.0
	▷ R01908 PTN STATION					
		399.0	396.0	395.0	391.0	389.0
		51.0	51.0	51.0	49.0	49.0
		761.0	761.0	761.0	758.0	754.0
		24.0	24.0	23.0	23.0	23.0
	▷	4.0	4.0	4.0	4.0	4.0
	▷ R31800 ND MANAGEMENT	28.0	28.0	27.0	27.0	27.0
	▷	142.5	140.5	138.5	137.5	137.5
		7.0	7.0	7.0	7.0	7.0
		149.5	147.5	145.5	144.5	144.5
	▷ R64725 VP PLANT SUPPORT	66.0	66.0	66.0	66.0	65.0
		8.0	8.0	8.0	8.0	8.0
		74.0	74.0	74.0	74.0	73.0
	▷ R65200 VP SAFETY ASSURANCE	79.0	79.0	79.0	78.0	77.0
		9.0	9.0	9.0	9.0	9.0
		88.0	88.0	88.0	87.0	86.0
	△ R31000 NUCLEAR DIVISION BUSINESS UNIT	1,894.5	1,888.5	1,884.5	1,879.5	1,868.5

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FPL Resp. to SFHHA Int. No. 291
Exhibit __(LK-13), Page 23 of 24

2007 -2008 -2009 Actual

Manpower Trend Report

BASA	
EAC	
Key Figures	
BRC	

Fiscal Year Variant	*Calendar year, 4 spec. periods*
BRC	NUC DIV BUS UNIT
EAC	FPL EMPLOYEES
Exp	*SUSPENSE*

Fiscal year/period	

	BRC	004/2009
Actual version	△ ▷ R01044 ENGINEERING SUPPORT SERVICES	44.0
		2.0
		46.0
	▷ R01905 ST. LUCIE PLANT	329.0
		361.0
		41.0
		731.0
	▷ R01908 PTN STATION	316.0
		388.0
		49.0
	▷	750.0
		25.0
		4.0
	▷ R31800 ND MANAGEMENT	29.0
	▷	140.5
		7.0
		147.5
	▷ R64725 VP PLANT SUPPORT	65.0
		8.0
		73.0
	▷ R65200 VP SAFETY ASSURANCE	77.0
		9.0
		86.0
	△ R31000 NUCLEAR DIVISION BUSINESS UNIT	1,882.5

EXHIBIT___(LK-14)

FLORIDA POWER AND LIGHT
SFHHA ADJUSTMENTS TO ELIMINATE NUCLEAR STAFF INCREASES
TEST YEAR ENDING DECEMBER 31, 2010
($ MILLIONS)

Source: Response to SFHHA Interrogatory No. 240

Per the response, FPL included $18.5 million in the test year for additional nuclear staffing related to O&M. The adjustment below includes a separate computation of payroll taxes and fringe benefits based on the analysis performed to compute the productivity reduction.

	O&M Amount
O&M Nuclear Staffing Increases by 2010	18.500
O&M Nuclear Staffing Increase Payroll Tax 2010	1.194
O&M Nuclear Staffing Incease Fr. Benefits	2.158
Total Nuclear Staffing Increase	21.852

EXHIBIT___(LK-15)

Q.
Regarding Testimony of FPL Witness J. A. Stall

Regarding page 31:5-11. Please specifically identify and describe FPL's efforts through litigation to seek recovery of past and future damages related to the US Government's failure to dispose of FPL's spent fuel, the current status of such litigation, and FPL's plan for accounting for any recoveries FPL makes in such litigation in terms of flowing recoveries back to ratepayers.

A.
In 1998, FPL filed a lawsuit against the U.S. Government seeking damages caused by the U.S. Department of Energy's (DOE) failure to dispose of spent nuclear fuel (SNF) from FPL's nuclear power plants. On March 31, 2009, FPL entered into a settlement agreement with the U.S. Government that resolves FPL's SNF damages claims against the Government. Under the settlement, FPL will receive from the Government a cash payment of $77.1 million, representing damages incurred related to DOE's SNF default through December 31, 2007. The settlement also formalizes an annual claim process that will enable FPL to submit and receive payment from the Government for annual SNF expenditures related to DOE's default. This process will enable FPL to recover its expenses relating to the long-term storage of SNF at FPL's nuclear power plants without the need for additional litigation.

The SNF settlement represents reimbursement for incremental costs incurred by FPL because DOE failed to meet its obligations in a timely manner. As these incremental costs were incurred by FPL they were charged either to base O&M or capitalized, resulting in an increase in capital structure and lowering the base ROE realized. The SNF settlement was subsequently recorded as a reduction to plant, CWIP, and O&M and reversal of previously incurred depreciation expense. Customers will receive the benefits associated with the SNF settlement through future rates. These reductions were forecasted in 2009 as achieved so current plant and depreciation expense reflects FPL's estimate of those settlement dollars received. Therefore, the 2010 plant balances used to calculate test year results reflect this estimated reduction and customers will receive the benefits associated with the SNF settlement through future rates. Reductions in prospective costs should likewise occur as DOE reimburses FPL for SNF costs incurred in 2009 and beyond. These refunds were not forecasted in the Test Year and Subsequent Year revenue requirements.

EXHIBIT___(LK-16)

Florida Power & Light Company
Docket No. 080677-EI
SFHHA's Second Set of Interrogatories
Interrogatory No. 120
Page 1 of 1

Q.
Interrogatories Directed to Ms. Kim Ousdahl:

Regarding Schedule C-41. Please state the capital costs and O&M expenses associated with smart meters up through and including meters that will be installed in 2010.

A.
The O&M and Capital expenditures related to Advanced Metering Infrastructure (AMI) are:

($Millions)

	2006	2007	2008	2009	2010
O&M	$0.98	$0.85	$1.39	$2.61	$7.40
Capital	$2.64	$1.15	$7.07	$43.68	$168.54

Please note that Capital expenditures are not included in Schedule C-41.

EXHIBIT__(LK-17)

Q.
Please provide a deployment timeline for the AMI program along with annual projections of costs and savings separated into capital and expense, including all supporting assumptions, data, computations, workpapers and electronic spreadsheets with formulas intact.

A.

Deployment	2009	2010	2011	2012	2013	Total
Meters (thousands)	170	1,128	1,099	1,076	873	4,346
	2009	2010	2011	2012	2013	Total
Capital (millions)	$43.7	$168.5	$156.7	$151.5	$122.5	$645.0
	2009	2010	2011	2012	2013	
O&M (Thousands)	$2,274	$6,883	$8,910	$11,882	$10,458	
Savings (Thousands)	$(167)	$(418)	$(4,700)	$(18,203)	$(30,401)	
Net O&M (Thousands)	$2,106	$6,465	$4,210	$(6,321)	$(19,943)	

Based on this deployment schedule, net O&M savings beyond 2013 will be greater than $30 million annually. See supporting documents provided in response to SFHHA's Tenth Request for Production of Documents No. 102.

EXHIBIT __(LK-18)

Florida Power & Light Company
Docket No. 080677-EI
SFHHA's Tenth Set of Interrogatories
Interrogatory No. 290
Page 1 of 1

Q.
Please provide a schedule showing the amounts included in each rate base component and each operating expense for the AMI program in each month for the prior year, the test year and in the subsequent year.

A.
See Attachment No. 1.

Florida Power & Light Company
Docket No. 080677-EI
SFHHA's Tenth Set of Interrogatories
Question No. 290
Attachment No. 1

Advanced Metering Infrastructure ("AMI")

Rate Base Components	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
CWIP												
Intangible Plant	$ 426,129	$ 852,258	$ 1,437,951	$ 2,014,442	$ 2,590,933	$ 4,189,824	$ 7,429,648	$ 8,101,924	$ 8,711,748	$ 9,321,572	$ 9,931,396	$ 11,126,974
Distribution 370	$ 6,326	$ 8,223	$ 19,438	$ 20,075	$ 22,007	$ 39,824	$ 92,076	$ 795,577	$ 1,618,521	$ 2,815,312	$ 3,423,594	$ 3,584,114
Total CWIP	$ 432,455	$ 860,481	$ 1,457,389	$ 2,034,517	$ 2,612,940	$ 4,229,648	$ 7,521,724	$ 8,897,501	$ 10,330,269	$ 12,136,884	$ 13,354,990	$ 14,711,088
Plant in Service												
Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution 370	$ 14,760	$ 33,947	$ 79,302	$ 126,145	$ 177,495	$ 270,416	$ 485,259	$ 2,341,607	$ 6,118,156	$ 12,687,218	$ 20,675,605	$ 29,038,537
Total Plant in Service	$ 14,760	$ 33,947	$ 79,302	$ 126,145	$ 177,495	$ 270,416	$ 485,259	$ 2,341,607	$ 6,118,156	$ 12,687,218	$ 20,675,605	$ 29,038,537
Accumulated Depreciation												
Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution 370	$ (25)	$ (106)	$ (295)	$ (637)	$ (1,143)	$ (1,890)	$ (3,149)	$ (7,860)	$ (21,960)	$ (53,302)	$ (108,907)	$ (191,764)
Total Accumulated Depreciation	$ (25)	$ (106)	$ (295)	$ (637)	$ (1,143)	$ (1,890)	$ (3,149)	$ (7,860)	$ (21,960)	$ (53,302)	$ (108,907)	$ (191,764)
Operating Expense												
O&M Expenses	$ 339,962	$ 90,512	$ 122,876	$ 83,147	$ 120,740	$ 121,227	$ 121,697	$ 187,669	$ 291,978	$ 154,157	$ 209,964	$ 262,549
Depreciation Expense												
Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution 370	$ 25	$ 81	$ 189	$ 342	$ 506	$ 747	$ 1,259	$ 4,711	$ 14,100	$ 31,342	$ 55,605	$ 82,857
Total Depreciation Expense	$ 25	$ 81	$ 189	$ 342	$ 506	$ 747	$ 1,259	$ 4,711	$ 14,100	$ 31,342	$ 55,605	$ 82,857

Florida Power & Light Company
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SFHHA's Tenth Set of Interrogatories
Question No. 290
Attachment No. 1

Advanced Metering Infrastructure ("AMI")

Rate Base Components	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
CWIP												
Intangible Plant	$ 11,731,893	$ 12,376,812	$ 13,810,468	$ 14,435,716	$ 15,795,814	$ 18,121,062	$ 18,799,560	$ 19,433,216	$ 20,566,872	$ 21,192,120	$ 21,817,368	$ 22,942,616
Distribution 370	$ 4,999,393	$ 5,412,588	$ 5,550,830	$ 5,579,421	$ 5,588,223	$ 5,628,700	$ 5,604,926	$ 5,612,421	$ 5,614,799	$ 5,609,525	$ 5,608,767	$ 5,526,761
Total CWIP	$ 16,751,286	$ 17,789,400	$ 19,361,298	$ 20,015,137	$ 21,384,037	$ 23,749,762	$ 24,404,486	$ 25,045,637	$ 26,181,671	$ 26,801,645	$ 27,426,135	$ 28,469,377
Plant in Service												
Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution 370	$ 40,703,789	$ 53,333,159	$ 66,285,096	$ 79,303,746	$ 92,342,934	$ 105,476,566	$ 118,554,726	$ 131,650,374	$ 144,751,572	$ 157,840,463	$ 170,927,587	$ 183,823,364
Total Plant in Service	$ 40,703,789	$ 53,333,159	$ 66,285,096	$ 79,303,746	$ 92,342,934	$ 105,476,566	$ 118,554,726	$ 131,650,374	$ 144,751,572	$ 157,840,463	$ 170,927,587	$ 183,823,364
Accumulated Depreciation												
Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution 370	$ (308,001)	$ (464,729)	$ (664,093)	$ (906,741)	$ (1,192,819)	$ (1,522,518)	$ (1,895,904)	$ (2,312,912)	$ (2,773,582)	$ (3,277,902)	$ (3,825,849)	$ (4,417,100)
Total Accumulated Depreciation	$ (308,001)	$ (464,729)	$ (664,093)	$ (906,741)	$ (1,192,819)	$ (1,522,518)	$ (1,895,904)	$ (2,312,912)	$ (2,773,582)	$ (3,277,902)	$ (3,825,849)	$ (4,417,100)
Operating Expense												
O&M Expenses	$ 602,198	$ 339,572	$ 411,646	$ 347,987	$ 380,971	$ 416,056	$ 559,246	$ 424,561	$ 922,828	$ 305,155	$ 278,226	$ 1,477,134
Depreciation Expense												
Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution 370	$ 116,237	$ 156,728	$ 199,364	$ 242,648	$ 286,078	$ 329,699	$ 373,385	$ 417,009	$ 460,670	$ 504,320	$ 547,947	$ 591,252
Total Depreciation Expense	$ 116,237	$ 156,728	$ 199,364	$ 242,648	$ 286,078	$ 329,699	$ 373,385	$ 417,009	$ 460,670	$ 504,320	$ 547,947	$ 591,252

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FPL Resp. to SFHHA Int. No. 290
Exhibit __(LK-18), Page 3 of 4

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FPL Resp. to SFHHA Int. No. 2
Exhibit __(LK-18), Page 4 of 4

Florida Power & Light Company
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Attachment No. 1

Advanced Metering Infrastructure ("AMI")

Rate Base Components	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
CWIP												
Intangible Plant	$ 23,339,004	$ 23,726,024	$ 24,613,418	$ 25,000,812	$ 25,388,206	$ 27,606,850	$ 27,994,244	$ 28,391,194	$ 29,278,588	$ 29,665,982	$ 30,053,376	$ 31,194,020
Distribution 370	$ 5,456,143	$ 5,400,370	$ 5,385,146	$ 5,382,484	$ 5,381,942	$ 5,318,557	$ 5,359,752	$ 5,389,121	$ 5,381,434	$ 5,405,300	$ 5,423,812	$ 5,269,815
Total CWIP	$ 28,795,147	$ 29,126,394	$ 29,998,564	$ 30,383,296	$ 30,770,148	$ 32,925,407	$ 33,353,996	$ 33,780,315	$ 34,660,022	$ 35,071,282	$ 35,477,188	$ 36,463,835
Plant in Service												
Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution 370	$ 196,554,365	$ 209,155,228	$ 221,720,567	$ 234,279,698	$ 246,837,563	$ 259,247,528	$ 271,753,618	$ 284,328,234	$ 296,884,914	$ 309,497,282	$ 322,152,843	$ 334,449,079
Total Plant in Service	$ 196,554,365	$ 209,155,228	$ 221,720,567	$ 234,279,698	$ 246,837,563	$ 259,247,528	$ 271,753,618	$ 284,328,234	$ 296,884,914	$ 309,497,282	$ 322,152,843	$ 334,449,079
Accumulated Depreciation												
Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution 370	$ (5,051,063)	$ (5,727,246)	$ (6,445,372)	$ (7,205,373)	$ (8,007,235)	$ (8,850,710)	$ (9,735,712)	$ (10,662,515)	$ (11,631,204)	$ (12,641,841)	$ (13,694,591)	$ (14,788,927)
Total Accumulated Depreciation	$ (5,051,063)	$ (5,727,246)	$ (6,445,372)	$ (7,205,373)	$ (8,007,235)	$ (8,850,710)	$ (9,735,712)	$ (10,662,515)	$ (11,631,204)	$ (12,641,841)	$ (13,694,591)	$ (14,788,927)
Operating Expense												
O&M Expenses	$ 485,869	$ 134,259	$ 153,521	$ (10,030)	$ 22,935	$ 55,898	$ 398,422	$ 77,603	$ 557,960	$ (39,128)	$ (60,873)	$ 2,434,098
Depreciation Expense												
Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution 370	$ 633,963	$ 676,183	$ 718,126	$ 760,000	$ 801,862	$ 843,475	$ 885,002	$ 926,803	$ 968,689	$ 1,010,637	$ 1,052,750	$ 1,094,337
Total Depreciation Expense	$ 633,963	$ 676,183	$ 718,126	$ 760,000	$ 801,862	$ 843,475	$ 885,002	$ 926,803	$ 968,689	$ 1,010,637	$ 1,052,750	$ 1,094,337

EXHIBIT___(LK-19)

Florida Power & Light Company
Docket No. 080677-EI
SFHHA's Tenth Set of Interrogatories
Interrogatory No. 283
Page 1 of 1

Q.
Regarding Schedule C-8 for the 2010 test year, page 1:26 and page 3:21-24. Please provide a more detailed explanation for the variance in account 902 for 2010 compared to 2009 than provided in Reason I. The explanation should include a description of why there is an expense increase of $4.8 million for the "full-scale deployment" of the AMI rather than a reduction in meter reading expenses.

A.
The $4.8 million increase in 2010 is driven by cost associated with the first full year of AMI deployment and includes expenses related to repair and replace unsafe meter conditions encountered during deployment and installation, customer marketing and mail-outs to educate the customers on the benefits of AMI, and severance. In addition, it includes expense associated with the operations of the project such as software maintenance and hosting fees for AMI communication vendor, network and field support, communication lines, and materials & supplies. The $0.5 million increase in 2010 associated with meter reading expense is net of $0.4 million in savings related to the AMI project.

EXHIBIT___(LK-20)

Q.
Regarding Testimony of FPL Witness Marlene M. Santos

Regarding pages 29:1-41:18. Please provide a date for when FPL anticipates it will have completed implementation of all smart meters, the ultimate number of customers FPL anticipates to provide with smart meters, describe the projected total cost of installing all smart meters, and the total costs savings upon implementation of all smart meters.

A.
Large scale AMI deployment is planned to begin later in 2009 and run through 2013. This deployment will replace approximately 4.3 million meters. The AMI meter will also be deployed to all new residential and small/medium service accounts as the customer population grows. The total cost of the project includes the integrated meter and installation, network field infrastructure and installation, software integration, software license fees and maintenance, servers, emergency repairs on electric service during installation, customer communication mail outs and operations. Total capital costs and cumulative O&M through 2013 is approximately \$645M and \$34M, respectively. The total savings associated with AMI are Customer Service operational savings, primarily driven by meter reading costs. The savings are approximately \$36M annually once fully implemented.

EXHIBIT___(LK-21)

Q.
Please provide a deployment timeline for the new CIS along with annual projections of costs and savings separated into capital and expense, including all supporting assumptions, data, computations, workpapers and electronic spreadsheets with formulas intact.

A.
The preliminary project assessment phase for CIS III will begin at the start of 2010. As a result, only a high-level timeline can be provided herein. Current plans are as follows:

- Project Assessment (including Business Case generation): planned completion - Feb 2010;
- Project Preparation: planned completion - June 2010;
- Business BluePrint: planned completion - Feb 2011;
- Realization: planned completion - Jan 2012;
- Final Preparation: completion - April 2012;
- Cutover / Go-Live: completion - June 2012.

Annual projected CIS III project costs:

- 2010 O&M: $7,250,000;
- 2011 O&M: $5,000,000;
- 2012 O&M: $19,000,000;
- 2010 Capital: $12,000,000;
- 2011 Capital: $76,000,000;
- 2012 Capital: $41,000,000.

EXHIBIT___(LK-22)

Q.
Please provide a schedule showing the amounts included in each rate base component and each operating expense for the new CIS in each month for the prior year, the test year and in the subsequent year.

A.
See Attachment No. 1.

Florida Power & Light Company
Docket No. 080677-EI
SFHHA's Tenth Set of Interrogatories
Question No. 288
Attachment No. 1

Customer Information System ("CIS")

Rate Base Components	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
CWIP												
Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
General Plant Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total CWIP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Plant in Service												
Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
General Plant Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Plant in Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation												
Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
General Plant Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Accumulated Depreciation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Operating Expenses												
O&M Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Depreciation Expense												
Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
General Plant Other	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Depreciation Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Florida Power & Light Company
Docket No. 080677-EI
SFHHA's Tenth Set of Interrogator
Question No. 288
Attachment No. 1

Docket No. 080677-EI
FPL Resp. to SFHHA Int. No. 288
Exhibit __(LK-22), Page 3 of 4

Customer Information System ("CIS")

Rate Base Components	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
CWIP												
Intangible Plant	$ 224,000	$ 380,800	$ 490,560	$ 567,392	$ 621,174	$ 658,822	$ 797,175	$ 894,023	$ 961,818	$ 1,009,271	$ 1,042,490	$ 1,065,743
General Plant Other	$ 384,000	$ 691,200	$ 936,960	$ 1,133,568	$ 1,290,854	$ 1,416,684	$ 1,709,347	$ 1,943,477	$ 2,130,782	$ 2,280,626	$ 2,400,500	$ 2,496,400
Total CWIP	$ 608,000	$ 1,072,000	$ 1,427,520	$ 1,700,960	$ 1,912,029	$ 2,075,506	$ 2,506,522	$ 2,837,500	$ 3,092,598	$ 3,289,897	$ 3,442,990	$ 3,562,143
Plant in Service												
Intangible Plant	$ 96,000	$ 259,200	$ 469,440	$ 712,608	$ 978,826	$ 1,261,178	$ 1,602,825	$ 1,985,977	$ 2,398,184	$ 2,830,729	$ 3,277,510	$ 3,734,257
General Plant Other	$ 96,000	$ 268,800	$ 503,040	$ 786,432	$ 1,109,146	$ 1,463,316	$ 1,880,653	$ 2,376,523	$ 2,909,218	$ 3,479,374	$ 4,078,500	$ 4,703,600
Total Plant in Service	$ 192,000	$ 528,000	$ 972,480	$ 1,499,040	$ 2,087,971	$ 2,724,494	$ 3,483,478	$ 4,362,500	$ 5,307,402	$ 6,310,103	$ 7,357,010	$ 8,437,857
Accumulated Depreciation												
Intangible Plant	$ (620)	$ (2,914)	$ (7,620)	$ (15,254)	$ (26,178)	$ (40,644)	$ (59,141)	$ (82,319)	$ (110,633)	$ (144,403)	$ (183,852)	$ (229,137)
General Plant Other	$ (620)	$ (2,976)	$ (7,961)	$ (16,289)	$ (28,531)	$ (45,145)	$ (66,806)	$ (94,365)	$ (128,502)	$ (169,761)	$ (218,579)	$ (275,303)
Total Accumulated Depreciation	$ (1,240)	$ (5,890)	$ (15,581)	$ (31,543)	$ (54,709)	$ (85,789)	$ (125,947)	$ (176,683)	$ (239,135)	$ (314,165)	$ (402,431)	$ (504,440)
Operating Expenses												
O&M Expense	$ 595,283	$ 595,283	$ 648,581	$ 595,283	$ 595,283	$ 595,283	$ 595,283	$ 648,581	$ 595,283	$ 595,283	$ 595,283	$ 595,291
Depreciation Expense												
Intangible Plant	$ 620	$ 2,294	$ 4,706	$ 7,634	$ 10,924	$ 14,467	$ 18,497	$ 23,178	$ 28,314	$ 33,770	$ 39,449	$ 45,284
General Plant Other	$ 620	$ 2,356	$ 4,985	$ 8,328	$ 12,242	$ 16,614	$ 21,661	$ 27,559	$ 34,137	$ 41,260	$ 48,818	$ 56,724
Total Depreciation Expense	$ 1,240	$ 4,650	$ 9,691	$ 15,962	$ 23,166	$ 31,081	$ 40,158	$ 50,737	$ 62,451	$ 75,030	$ 88,267	$ 102,008

Florida Power & Light Company
Docket No. 080677-EI
SFHHA's Tenth Set of Interrogator
Question No. 288
Attachment No. 1

Customer Information System ("CIS")

Rate Base Components	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
CWIP												
Intangible Plant	$ 2,164,687	$ 2,933,948	$ 3,472,430	$ 3,849,368	$ 4,113,224	$ 4,297,924	$ 5,136,647	$ 5,723,583	$ 6,134,508	$ 6,422,155	$ 6,623,509	$ 6,764,456
General Plant Other	$ 4,429,120	$ 5,975,297	$ 7,212,237	$ 8,201,790	$ 8,993,432	$ 9,626,746	$ 11,349,397	$ 12,727,517	$ 13,830,014	$ 14,712,011	$ 15,417,609	$ 15,982,086
Total CWIP	$ 6,593,807	$ 8,909,244	$ 10,684,667	$ 12,051,158	$ 13,106,656	$ 13,924,670	$ 16,465,943	$ 18,451,100	$ 19,964,522	$ 21,134,167	$ 22,041,118	$ 22,746,542
Plant in Service												
Intangible Plant	$ 4,661,980	$ 5,919,386	$ 7,407,570	$ 9,057,299	$ 10,820,110	$ 12,662,077	$ 14,863,454	$ 17,316,418	$ 19,945,493	$ 22,697,845	$ 25,536,492	$ 28,435,544
General Plant Other	$ 5,810,880	$ 7,304,704	$ 9,107,763	$ 11,158,211	$ 13,406,569	$ 15,813,255	$ 18,650,604	$ 21,832,484	$ 25,289,987	$ 28,967,990	$ 32,822,382	$ 36,817,914
Total Plant in Service	$ 10,472,860	$ 13,224,090	$ 16,515,334	$ 20,215,510	$ 24,226,679	$ 28,475,332	$ 33,514,058	$ 39,148,902	$ 45,235,480	$ 51,665,835	$ 58,358,884	$ 65,253,458
Accumulated Depreciation												
Intangible Plant	$ (283,362)	$ (351,700)	$ (437,770)	$ (544,106)	$ (672,481)	$ (824,137)	$ (1,001,908)	$ (1,209,734)	$ (1,450,384)	$ (1,725,789)	$ (2,037,302)	$ (2,385,871)
General Plant Other	$ (343,209)	$ (427,914)	$ (533,911)	$ (664,796)	$ (823,443)	$ (1,012,155)	$ (1,234,734)	$ (1,496,187)	$ (1,800,520)	$ (2,150,936)	$ (2,549,999)	$ (2,999,759)
Total Accumulated Depreciation	$ (626,572)	$ (779,614)	$ (971,681)	$ (1,208,901)	$ (1,495,924)	$ (1,836,291)	$ (2,236,639)	$ (2,705,921)	$ (3,250,903)	$ (3,876,724)	$ (4,587,301)	$ (5,385,630)
Operating Expenses												
O&M Expense	$ 416,667	$ 416,667	$ 416,667	$ 416,667	$ 416,667	$ 416,667	$ 416,667	$ 416,667	$ 416,667	$ 416,667	$ 416,667	$ 416,663
Depreciation Expense												
Intangible Plant	$ 54,226	$ 68,338	$ 86,070	$ 106,336	$ 128,375	$ 151,656	$ 177,769	$ 207,826	$ 240,650	$ 275,405	$ 311,513	$ 348,569
General Plant Other	$ 67,906	$ 84,705	$ 105,997	$ 130,884	$ 158,648	$ 188,711	$ 222,579	$ 261,453	$ 304,333	$ 350,416	$ 399,083	$ 449,760
Total Depreciation Expense	$ 122,132	$ 153,043	$ 192,067	$ 237,220	$ 287,022	$ 340,367	$ 400,348	$ 469,282	$ 544,982	$ 625,821	$ 710,576	$ 798,330

EXHIBIT___(LK-23)

Florida Power & Light Company
Docket No. 080677-EI
SFHHA's Tenth Set of Interrogatories
Interrogatory No. 284
Page 1 of 1

Q.
Regarding Schedule C-8 for the 2010 test year, page 1:28 and page 3:26-32. Please provide a more detailed explanation for the variance in account 903 for 2010 compared to 2009 than provided in Reason J. The explanation should include a description of why there is an increase in expense for a new Customer Information System ("CIS") rather than capitalization of the amounts to a plant account.

A.
Projected increase in spending in 2010 can be mainly attributed to cost associated with the CISII system replacement project. Some of the project costs in 2010 which will be expensed (as opposed to capitalized) in accordance with SOP-98 (**Statement of Position (SOP) 98-1: Accounting for the Costs of Computer Software**) include: 1) Preparation of detailed project plan; 2) Review of scope and preliminary project requirements; 3) Approval of Scoping Study documentation; and 4) Start preparing for data conversion.

EXHIBIT___(LK-24)

FLORIDA POWER AND LIGHT
SFHHA ADJUSTMENTS TO REFLECT DEFERRAL OF CIS O&M EXPENSE
TEST YEAR ENDING DECEMBER 31, 2010
($ MILLIONS)

Source: SFHHA Interrogatories 287 and 288

CIS Reflected as O&M in Test Year	7.250
Grossed Up for Bad Debt Expense and Regulatory Assessment Fee	100.33%
CIS Reflected as O&M in Test Year Grossed Up	7.274
Increase to Rate Base to Capitalize or Defer O&M Costs	7.250
Average Increase to Rate Base in Test Year	3.625
FPL Filed Grossed Up Rate of Return	11.80%
Revenue Requirement Effect of Capitalization/Deferral	0.428

EXHIBIT___(LK-25)

FLORIDA POWER AND LIGHT
SFHHA CAPITAL EXPENDITURE REDUCTIONS
TEST YEAR ENDING DECEMBER 31, 2010
($ MILLIONS)

Source: Response to SFHHA Inter 279 and Depreciation Study Exhibit CRC-1 Page 49 of 720

	2009 Budget	2009 Actual	Reduction
January-09	235	167	(68)
February-09	200	127	(73)
March-09	237	242	5
April-09	225	191	(34)
Total First Four Months	897	727	(170)
Percentage Reduction First Four Months			-19.0%
Total Annual Budget for 2009			2,790
	2009	**2010**	**Total**
Total Annual Capital Reduction for 2009	(529)	-	(529)
Average Capital Reduction for 2010		(264)	(264)
Total Test Year Capital Reduction	(529)	(264)	(793)
Jurisdictional Allocation for Gross Plant - Schedule B-1	0.988940	0.988940	
Jurisdictional Test Year Capital Reduction	(523)	(261)	(784)
FPL Filed Grossed Up Rate of Return	11.80%	11.80%	
Revenue Requirement Effect of Capital Expenditure Reduction-Gross Plant	(61.719)	(30.801)	(92.520)
Composite Depreciation Rate - Based on FPL Remaining Life Method	3.39%	3.39%	
Reduction in Depreciation Expense - Total Company	(17.933)	(8.950)	(26.883)
Jurisdictional Allocation for Gross Plant - Schedule C-1	0.990615	0.990615	0.990615
Jurisdictional Reduction in Depreciation Expense	(17.765)	(8.866)	(26.630)
Annual Accumulated Depreciation Reduction	17.765	8.866	
Time Period To Apply Reduction	1.5 Years	.5 Years	
Accumulated Depreciation Reduction - Increase to Rate Base	26.647	4.433	31.080
FPL Filed Grossed Up Rate of Return	11.80%	11.80%	
Revenue Requirement Effect of Accumulated Depreciation Reduction	3.145	0.523	3.668
Total Revenue Requirement Effect of Capital Cost Reductions	(76.340)	(39.143)	(115.483)

EXHIBIT___(LK-26)

Florida Power & Light Company

Table 5. Comparison of Theoretical Reserve and Book Reserve based on Plant in Service as of December 31, 2009

	Original Cost	Theoretical Reserve	Book Reserve	Reserve Variance
	(1)	(2)	(3)	(4) = (3) - (2)
Steam				
311 Structures & Improvements	607,383,884	371,032,445	450,480,572	79,448,127
312 Boiler Plant Equipment	1,520,058,000	827,288,045	1,022,923,266	195,637,221
314 Turbogenerator Units	656,903,762	324,858,642	420,826,473	95,967,831
315 Accessory Electric Equipment	215,129,268	118,935,460	150,422,294	31,486,834
316 Miscellaneous Equipment	37,208,440	20,480,939	28,051,100	7,570,161
Total Steam	3,036,683,354	1,662,593,531	2,072,703,705	410,110,174
Nuclear				
321 Structures & Improvements	1,174,690,191	563,046,279	661,926,379	98,880,100
322 Reactor Plant Equipment	1,862,733,318	694,663,703	855,060,882	160,397,179
323 Turbogenerator Units	262,505,086	126,028,876	186,406,688	60,377,812
324 Accessory Electric Equipment	581,096,429	322,433,151	362,757,426	40,324,275
325 Miscellaneous Equipment	89,457,913	37,498,895	55,026,788	17,527,893
Total Nuclear	3,970,482,937	1,743,670,904	2,121,178,163	377,507,259
Combined Cycle				
341 Structures & Improvements	368,040,843	179,939,429	159,404,481	(20,534,948)
342 Fuel Holders, Producers & Accessories	82,917,606	37,534,832	41,033,160	3,498,328
343 Prime Movers	2,893,397,511	753,421,499	801,742,016	48,320,517
344 Generators	322,410,125	136,588,910	105,796,420	(30,792,490)
345 Accessory Electric Equipment	399,748,476	153,152,145	172,286,784	19,134,639
346 Misc. Power Plant Equipment	49,873,002	16,965,625	23,284,289	6,318,664
Total Combined Cycle	4,116,385,564	1,277,602,440	1,303,547,150	25,944,710
Combustion Turbine				
341 Structures & Improvements	13,869,690	12,464,080	12,046,516	(417,564)
342 Fuel Holders, Producers & Accessories	15,203,834	10,513,390	15,585,942	5,072,552
343 Prime Movers	112,800,506	62,987,847	91,301,391	28,313,544
344 Generators	51,167,864	46,554,280	42,187,783	(4,366,497)
345 Accessory Electric Equipment	22,215,820	12,853,378	12,286,406	(566,972)
346 Misc. Power Plant Equipment	421,309	378,083	370,806	(7,277)
Total Combustion Turbine	215,678,824	145,751,058	173,778,844	28,027,786
T, D and G				
Transmission	3,122,536,022	1,048,319,348	1,032,681,912	(15,637,436)
Distribution	10,060,556,895	3,559,394,856	3,899,924,205	340,529,349
General	672,093,362	232,057,078	310,935,651	78,878,573
Total T, D and G	13,845,186,279	4,839,771,282	5,243,541,768	403,770,486
TOTAL PLANT IN SERVICE	25,184,406,958	9,669,389,215	10,914,749,630	1,245,360,415

Note: The book reserve shown includes the allocation of the $500 M Depreciation Expense Credit

EXHIBIT___(LK-27)

FLORIDA POWER AND LIGHT
SFHHA AMORTIZATION OF DEPRECIATION RESERVE SURPLUS
TEST YEAR ENDING DECEMBER 31, 2010
($ MILLIONS)

Source: Depreciation Study Exhibit CRC-1 Page 53 of 720

Depreciation Reserve Surplus at January 1, 2010	1,245.360
Amortization Period Recommended by SFHHA	5 Years
Annual Depreciation Expense Reduction	(249.072)
Jurisdictional Allocation for Depreciation - Schedule C-1	0.990615
Jurisdictional Depreciation Reduction	(246.735)
Annual Accumulated Depreciation Reduction	246.735
Time Period To Apply Reduction	.5 Years
Accumulated Depreciation Reduction - Increase to Rate Base	123.367
FPL Filed Grossed Up Rate of Return	11.80%
Revenue Requirement Effect of Accumulated Depreciation Reduction	14.559
Total Revenue Requirement Effect of Amortization of Depr Reserve Surplus	(232.176)

EXHIBIT___(LK-28)

FLORIDA POWER AND LIGHT
SFHHA ADJUSTMENTS TO COMPANY PROPOSED CAPITAL COSTS RECOVERY OVER FOUR YEARS
TEST YEAR ENDING DECEMBER 31, 2010
($ MILLIONS)

Source: Depreciation Study Exhibit CRC-1 *Pages 55 through 57 of 720* and page 39 of 720

	Unrecovered Costs	FPL's Amortization Period	FPL Annual Depr	SFHHA Amortization Period or Rate	SFHHA Annual Depr	SFHHA Depr Reduction
Unrecovered Costs of Cape Canaveral at January 1, 2010						
Cape Canaveral Common	3.539	4	0.885	0	-	(0.885)
Cape Canaveral Unit 1	23.148	4	5.787	0	-	(5.787)
Cape Canaveral Unit 2	8.616	4	2.154	0	-	(2.154)
Unrecovered Costs of Cape Canaveral at January 1, 2010						
Riviera Common	0.057	4	0.014	0	-	(0.014)
Riviera Unit 1	5.664	4	1.416	0	-	(1.416)
Riviera Unit 2	3.883	4	0.971	0	-	(0.971)
Unrecovered Costs of Nuclear Uprates at January 1, 2010						
St. Lucie Unit 1	40.821	4	10.205	27	1.512	(8.693)
St. Lucie Unit 2	37.448	4	9.362	34	1.101	(8.261)
Turkey Point Common	2.149	4	0.537	24	0.090	(0.448)
Turkey Point Unit 3	43.931	4	10.983	23	1.910	(9.073)
Turkey Point Unit 4	43.886	4	10.972	24	1.829	(9.143)
Unrecovered Costs of Acct 370 Meters Made Obsolete by AMI	101.082	4	25.270	3.26%	8.120	(17.151)
Total Unrecovered Costs at January 1, 2010	314.223		78.556		14.561	(63.994)
Jurisdictional Allocation for Depreciation - Schedule C-1						0.990615
Jurisdictional Depreciation Reduction						(63.394)
Gross Cost of Meters Used in AMI Change Computation Above	249.077					

EXHIBIT___(LK-29)

THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 2/29/2009)
Form 1-F Approved
OMB No. 1902-0029
(Expires 2/28/2009)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 2/28/2009)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Florida Power & Light Company	End of 2008/Q4

FERC FORM No.1/3-Q (REV. 02-04)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power & Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Putnam* (b)			Plant Name: *Sanford* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combined Cycle			Combined Cycle		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Full Outdoor			Conventional		
3	Year Originally Constructed	1977			2002		
4	Year Last Unit was Installed	1978			2003		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	580.00			2378.00		
6	Net Peak Demand on Plant - MW (60 minutes)	506			2105		
7	Plant Hours Connected to Load	4268			8773		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	496			1907		
10	When Limited by Condenser Water	478			1788		
11	Average Number of Employees	36			55		
12	Net Generation, Exclusive of Plant Use - KWh	1168216000			10673778000		
13	Cost of Plant: Land and Land Rights	37983			2612675		
14	Structures and Improvements	11535532			73873781		
15	Equipment Costs	176618382			650920220		
16	Asset Retirement Costs	0			0		
17	Total Cost	188191897			727206676		
18	Cost per KW of Installed Capacity (line 17/5) Including	324.4688			305.8060		
19	Production Expenses: Oper, Supv, & Engr	1149870			1195533		
20	Fuel	122839246			808475919		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	839435			1113514		
26	Misc Steam (or Nuclear) Power Expenses	844136			1839060		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	509366			776444		
30	Maintenance of Structures	592560			319115		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	1336920			5253737		
33	Maintenance of Misc Steam (or Nuclear) Plant	57450			362630		
34	Total Production Expenses	128169983			819435952		
35	Expenses per Net KWh	0.1097			0.0768		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil	Gas		Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Barrels	Mcf		Mcf		
38	Quantity (Units) of Fuel Burned	690	11371948	0	76417286	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	138310	1031325	0	1031885	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	66.296	10.798	0.000	10.580	0.000	0.000
41	Average Cost of Fuel per Unit Burned	66.296	10.798	0.000	10.580	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	11.413	10.798	0.000	10.580	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.105	0.000	0.076	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	10043.000	0.000	7388.000	0.000	0.000

EXHIBIT ___(LK-30)

Florida Power & Light Company

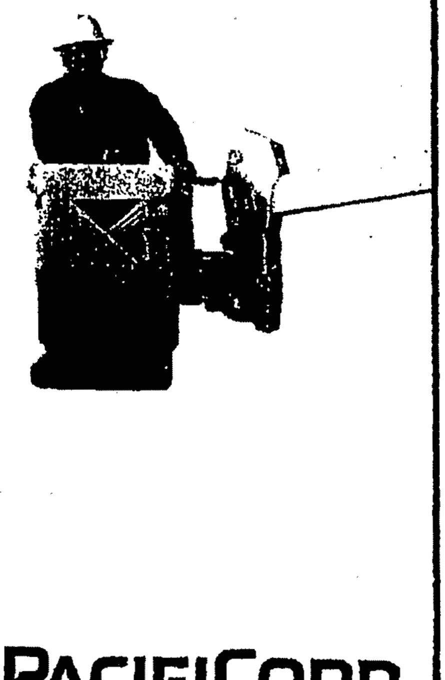
Table 13. Comparison of Existing and Proposed Remaining Life Depreciation Rates based on Electric Generation Plant in Service as of December 31, 2009

	Original Cost	Book Reserve	Existing Net Salvage	Existing Annual Depreciation Rate	Existing Annual Depreciation Amount	Proposed Life Span Date	Proposed Survivor Curve	Proposed Net Salvage	Proposed Annual Depreciation Rate	Proposed Annual Depreciation Amount	Increase/Decrease
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11) = (10) - (5)
COMBINED CYCLE PRODUCTION PLANT											
Putnam Combined Cycle Plant											
Putnam Common											
341 Structures & Improvements	12,728,938	9,449,327	(2)	4.10	521,886	6-2020	25 - R5	(12)	18.97	2,414,572	1,892,686
342 Fuel Holders, Producers & Accessories	11,435,870	8,470,029	0	3.70	423,120	6-2020	22 - R3	(3)	2.97	339,209	(83,911)
343 Prime Movers	20,146,555	11,834,908	0	6.30	1,269,233	6-2020	50 - R1 (a)	(2)	4.17	840,832	(428,401)
344 Generators	170,569	47,851	(1)	3.80	6,482	6-2020	30 - R5	(11)	8.04	13,712	7,230
345 Accessory Electric Equipment	1,623,348	1,111,882	(1)	4.20	63,981	6-2020	28 - R4	(3)	6.24	95,007	31,026
346 Misc. Power Plant Equipment	1,440,520	981,518	0	3.70	53,299	6-2020	22 - R4	0	7.09	102,062	48,763
Total Putnam Common	47,445,586	31,895,293			2,338,007					3,805,394	1,467,393
Putnam Unit 1											
341 Structures & Improvements	38,646	31,993	(2)	4.50	1,735	6-2020	25 - R5	(12)	17.72	6,832	5,097
342 Fuel Holders, Producers & Accessories	68,736	56,064	0	4.10	2,818	6-2020	22 - R3	(3)	3.64	2,499	(319)
343 Prime Movers	61,302,516	42,334,924	0	5.20	3,187,731	6-2020	50 - R1 (a)	(2)	3.03	1,859,389	(1,328,342)
344 Generators	7,708,123	5,576,593	(1)	6.40	418,239	6-2020	30 - R5	(11)	6.34	489,792	72,553
345 Accessory Electric Equipment	7,169,774	5,892,353	(1)	4.30	307,870	6-2020	28 - R4	(3)	2.32	237,861	(70,009)
346 Misc. Power Plant Equipment	407,903	332,744	0	4.10	16,720	6-2020	22 - R4	0	7.81	31,838	15,118
Total Putnam Unit 1	76,695,497	54,224,691			3,933,113					2,627,209	(1,305,904)
Putnam Unit 2											
341 Structures & Improvements	38,546	27,526	(2)	4.40	1,696	6-2020	25 - R5	(12)	28.44	10,964	9,268
342 Fuel Holders, Producers & Accessories	68,672	48,857	0	4.10	2,816	6-2020	22 - R3	(3)	7.19	4,935	2,119
343 Prime Movers	59,896,462	39,409,582	0	5.40	3,234,409	6-2020	50 - R1 (a)	(2)	3.47	2,078,665	(1,155,744)
344 Generators	7,979,287	6,074,669	(1)	6.60	526,630	6-2020	20 - R6	(11)	4.61	368,010	(158,620)
345 Accessory Electric Equipment	7,332,410	5,184,098	(1)	4.20	307,961	6-2020	28 - R4	(3)	7.92	581,068	273,107
346 Misc. Power Plant Equipment	392,093	278,918	0	4.10	16,078	6-2020	22 - R4	0	17.51	68,668	52,592
Total Putnam Unit 2	75,707,420	51,113,944			4,089,588					3,112,310	(977,278)
Total Putnam Combined Cycle Plant	198,838,515	137,232,928			10,358,702					9,544,913	(815,789)

EXHIBIT___(LK-31)

Let's turn the answers

2008
Integrated Resource Plan
Volume I



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May 28, 2009

Pacific Power | Rocky Mountain Power | PacifiCorp Energy

Table 6.2 – East Side Supply-Side Resource Options

	Location / Timing		Plant Details			Outage Information		Costs				Emissions			
Description	Installation	Earliest In-Service Date	Average Capacity	Design Plant Life	Annual Heat Rate	Maint. Outage	Equivalent Forced Outage	Low Estimate Capital Cost	High Estimate Capital Cost	Var O&M	Fixed O&M	SO2	NOx	Hg	CO2
	Location	Mid-Year	(MW)	in Years	BTU/kWh	Rate	Rate (EFOR)	($/kW)	($/kW)	($/MWh)	($/kW-yr)	lbs/MMBtu	lbs/MMBtu	lbs/TBtu	lbs/MMBtu
East Side Options (4500')															
Coal															
Utah PC without Carbon Capture & Sequestration	Utah	2020	600	40	9,106	5%	4%	2,708	3,521	$ 0.96	$ 38.87	0.100	0.070	0.41	205.35
Utah PC with Carbon Capture & Sequestration	Utah	2025	526	40	13,087	5%	5%	5,040	6,367	$ 6.71	$ 66.07	0.050	0.020	0.20	20.54
Utah IGCC with Carbon Capture & Sequestration	Utah	2025	466	40	10,823	7%	8%	4,880	6,164	$ 11.28	$ 53.24	0.050	0.011	0.04	20.54
Wyoming PC without Carbon Capture & Sequestration	Wyoming	2020	780	40	9,214	5%	4%	3,156	3,987	$ 1.27	$ 36.00	0.100	0.070	0.41	205.35
Wyoming PC with Carbon Capture & Sequestration	Wyoming	2025	692	40	13,242	5%	5%	5,707	7,209	$ 7.36	$ 61.37	0.050	0.020	0.35	20.54
Wyoming IGCC with Carbon Capture & Sequestration	Wyoming	2025	456	40	11,047	7%	8%	5,535	6,972	$ 13.52	$ 36.00	0.050	0.011	0.06	20.50
Existing PC with Carbon Capture & Sequestration (500 MW)	UT / WY	2026	(139)	20	14,372	5%	5%	1,253	1,583	$ 6.71	$ 66.07	0.050	0.011	0.10	20.50
Natural Gas															
Utility Cogeneration	Utah	2011	10	15	4,974	10%	8%	4,832	6,091	$ 23.27	$ 1.56	-	-	0.26	118.00
Fuel Cell - Large	Utah	2013	5	25	7,362	3%	3%	1,704	2,153	$ 0.03	$ 9.40	0.001	-	0.26	118.00
SCCT Aero	Utah	2013	118	30	9,771	4%	3%	1,070	1,351	$ 5.63	$ 9.95	0.001	0.011	0.26	118.00
Intercooled Aero SCCT	Utah	2012	174	30	9,402	4%	3%	999	1,261	$ 2.71	$ 3.64	0.001	0.011	0.26	118.00
Intercooled Aero SCCT	Utah	2012	261	30	9,401	4%	3%	999	1,262	$ 2.71	$ 4.04	0.001	0.011	0.26	118.00
Intercooled Aero SCCT	Wyoming	2013	241	30	9,472	4%	3%	1,083	1,368	$ 2.94	$ 4.19	0.001	0.011	0.35	118.00
Internal Combustion Engines	Utah	2009	153	30	8,500	5%	1%	1,256	1,589	$ 5.30	$ 12.80	0.001	0.011	0.26	118.00
SCCT Frame (2 Frame "F")	Utah	2012	202	35	11,659	4%	3%	710	897	$ 4.47	$ 3.24	0.001	0.097	0.26	118.00
SCCT Frame (2 Frame "F")	Wyoming	2012	175	35	11,659	4%	3%	720	972	$ 4.85	$ 4.05	0.001	0.026	0.26	118.00
CCCT (Wet "F" 1x1)	Utah	2013	222	40	7,302	4%	3%	1,206	1,648	$ 2.94	$ 12.79	0.001	0.050	0.26	118.00
CCCT Duct Firing (Wet "F" 1x1)	Utah	2013	50	40	8,869	4%	3%	530	689	$ 0.39	$ 1.60	0.001	0.011	0.26	118.00
CCCT (Wet "F" 2x1)	Utah	2013	505	40	7,098	4%	3%	1,162	1,493	$ 2.94	$ 7.27	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "F" 2x1)	Utah	2013	64	40	8,557	4%	3%	596	753	$ 0.39	$ 1.68	0.001	0.011	0.35	118.00
CCCT (Dry "F" 2x1)	Utah	2017	438	40	7,168	4%	3%	1,212	1,530	$ 3.35	$ 9.69	0.001	0.011	0.26	118.00
CCCT Duct Firing (Dry "F" 2x1)	Utah	2013	98	40	8,950	4%	3%	611	772	$ 0.31	$ 1.60	0.001	0.011	0.26	118.00
CCCT (Wet "G" 1x1)	Utah	2013	333	40	6,884	4%	3%	1,227	1,550	$ 4.56	$ 6.75	0.001	0.012	0.26	118.00
CCCT Duct Firing (Wet "G" 1x1)	Utah	2013	72	40	9,021	4%	3%	520	654	$ 0.36	$ 1.63	0.001	0.011	0.26	118.00
CCCT Advanced (Wet)	Utah	2018	400	40	6,760	4%	3%	1,355	1,112	$ 4.56	$ 6.75	0.001	0.011	0.26	118.00
CCCT Advanced Duct Firing (Wet)	Utah	2018	75	40	9,021	4%	3%	665	841	$ 0.36	$ 1.63	0.001	0.011	0.26	118.00
Other - Renewables															
East (Wyoming) Wind (35% CF)	Wyoming	2010	100	25	n/a	n/a	n/a	2,215	2,954	-	$ 31.43	-	-	-	-
East Side Geothermal (Blundell)	Utah	2013	35	40	n/a	5%	5%	5,762	7,304	$ 5.94	$ 110.85	-	-	-	-
East Side Geothermal (Green Field)	Utah	2013	35	40	n/a	5%	5%	5,782	7,304	$ 5.94	$ 110.85	-	-	-	-
Battery Storage	Utah	2016	5	10	12,000	2%	5%	1,986	2,501	$ 18.60	$ 1.10	0.100	0.600	3.00	205.35
Pumped Storage	Nevada	2018	350	50	13,000	5%	5%	1,684	2,127	$ 4.30	$ 4.30	0.100	0.300	3.40	205.35
Compressed Air Energy Storage (CAES)	Wyoming	2015	350	30	17,980	4%	3%	1,483	1,873	$ 5.50	$ 3.80	0.001	0.011	0.26	118.00
Recovered Energy Generation (CHP)	UT / WY	2011	12	30	-	8%	8%	5,300	3,500	-	$ 91.92	-	-	-	-
Nuclear	Utah	2025	1,600	40	10,718	7%	8%	5,188	6,553	$ 1.63	$ 146.70	-	-	-	-
Solar Concentrating (PV) - 30% CF	Utah	2015	10	20	n/a	n/a	n/a	6,194	7,824	-	$ 180.00	-	-	-	-
Solar Concentrating (natural gas backup) - 25% solar	Utah	2015	250	30	n/a	n/a	n/a	3,983	4,980	-	$ 195.68	-	-	-	-
Solar Concentrating (thermal storage) - 30% solar	Utah	2012	250	30	n/a	n/a	n/a	4,418	5,580	-	$ 138.50	-	-	-	-

Table 6.3 – West Side Supply-Side Resource Options

	Location / Timing		Plant Details			Outage Information		Costs				Emissions			
Description	Installation Location	Earliest In-Service Date Mid-Year	Average Capacity (MW)	Design Plant Life in Years	Annual Heat Rate BTU/kWh	Maint. Outage Rate	Equivalent Forced Outage Rate (EFOR)	Low Estimate Capital Cost ($/kW)	High Estimate Capital Cost ($/kW)	Var O&M ($/MWh)	Fixed O&M ($/kW-yr)	SO2 lbs/MMBtu	NOx lbs/MMBtu	Hg lbs/TBtu	CO2 lbs/MMBtu
West Side Options (1500')															
Natural Gas															
Fuel Cell - Large	Northwest	2011	5	25	7,262	3%	3%	1,704	2,153	$ 0.03	$ 8.48	0.001	-	0.26	118.00
SCCT Aero	Northwest	2012	137	30	9,773	4%	3%	972	1,228	$ 5.12	$ 9.04	0.001	0.011	0.26	118.00
Intercooled Aero SCCT	Northwest	2012	297	30	9,402	4%	3%	906	1,147	$ 2.46	$ 3.68	0.001	0.011	0.26	118.00
Internal Combustion Engines	Northwest	2012	168	30	8,500	5%	1%	1,143	1,444	$ 5.20	$ 12.80	0.001	0.017	0.26	118.00
SCCT Frame (2 Frame "F")	Northwest	2012	338	35	11,659	4%	3%	645	815	$ 4.07	$ 3.40	0.001	0.050	0.26	118.00
CCCT (Wet "F" 1x1)	Northwest	2013	244	40	7,302	4%	3%	1,180	1,491	$ 2.67	$ 11.62	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "F" 1x1)	Northwest	2013	55	40	8,869	4%	3%	482	608	$ 4.36	$ 1.45	0.001	0.011	0.26	118.00
CCCT (Wet "F" 2x1)	Northwest	2013	557	40	7,098	4%	3%	1,074	1,357	$ 2.67	$ 7.07	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "F" 2x1)	Northwest	2013	70	40	8,557	4%	3%	542	685	$ 0.36	$ 1.45	0.001	0.011	0.26	118.00
CCCT (Wet "G" 1x1)	Northwest	2013	347	40	6,884	4%	3%	1,116	1,409	$ 4.14	$ 6.13	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "G" 1x1)	Northwest	2013	83	40	9,021	4%	3%	472	597	$ 0.33	$ 1.48	0.001	0.011	0.26	118.00
CCCT Advanced (Wet)	Northwest	2018	440	40	6,760	4%	3%	1,232	1,556	$ 4.14	$ 6.13	0.001	0.011	0.26	118.00
CCCT Advanced Duct Firing (Wet)	Northwest	2018	83	40	9,021	4%	3%	605	764	$ 0.33	$ 1.48	0.001	0.011	0.26	118.00
Other - Renewables															
West Wind	Northwest	2010	50	25	n/a	n/a	n/a	2,350	3,134	-	$ 31.43	-	-	-	-
Biomass	Northwest	2015	50	30	10,979	5%	4%	3,179	4,016	$ 0.96	$ 38.80	0.100	0.350	0.40	205.39
West Side Geothermal (Green Field)	Northwest	2013	35	40	n/a	5%	5%	5,783	7,304	$ 5.94	$ 110.85	-	-	-	-
Compressed Air Energy Storage (CAES)	Northwest	2015	385	30	11,980	4%	3%	1,483	1,873	$ 5.01	$ 3.45	0.001	0.011	0.26	118.00
Hydrokinetic (Wave) - 21% CF	Northwest	2015	100	30	n/a	n/a	n/a	5,700	7,200	-	$ 180.00	-	-	-	-
West Side Options (Sea Level)															
Natural Gas															
Fuel Cell - Large	Northwest	2013	5	25	7,262	2%	3%	1,704	2,153	$ 0.03	$ 8.48	0.001	-	0.26	118.00
SCCT Aero	Northwest	2012	136	30	9,773	2%	3%	924	1,167	$ 4.87	$ 8.59	0.001	0.011	0.26	118.00
Intercooled Aero SCCT	Northwest	2012	302	30	9,402	4%	3%	863	1,090	$ 2.35	$ 3.49	0.001	0.011	0.26	118.00
Internal Combustion Engines	Northwest	2012	177	30	8,500	4%	1%	1,086	1,372	$ 5.30	$ 12.80	0.001	0.017	0.26	118.00
SCCT Frame (2 Frame "F")	Northwest	2013	356	35	11,659	5%	3%	613	774	$ 3.87	$ 3.23	0.001	0.050	0.26	118.00
CCCT (Wet "F" 1x1)	Northwest	2013	257	40	7,302	4%	3%	1,121	1,416	$ 2.55	$ 11.07	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "F" 1x1)	Northwest	2013	58	40	8,869	4%	3%	458	578	$ 0.34	$ 1.38	0.001	0.011	0.26	118.00
CCCT (Wet "F" 2x1)	Northwest	2013	586	40	7,098	4%	3%	1,020	1,289	$ 2.55	$ 6.73	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "F" 2x1)	Northwest	2013	74	40	8,557	4%	3%	515	650	$ 0.34	$ 1.38	0.001	0.011	0.26	118.00
CCCT (Wet "G" 1x1)	Northwest	2013	386	40	6,884	4%	3%	1,060	1,339	$ 3.94	$ 5.84	0.001	0.011	0.26	118.00
CCCT Duct Firing (Wet "G" 1x1)	Northwest	2010	84	40	9,021	4%	3%	449	567	$ 0.31	$ 1.41	0.001	0.011	0.26	118.00
CCCT Advanced (Wet)	Northwest	2018	463	40	6,760	4%	3%	1,170	1,479	$ 3.94	$ 5.84	0.001	0.011	0.26	118.00
CCCT Advanced Duct Firing (Wet)	Northwest	2018	87	40	9,021	4%	3%	574	725	$ 0.31	$ 1.41	0.001	0.011	0.26	119.00

EXHIBIT___(LK-32)

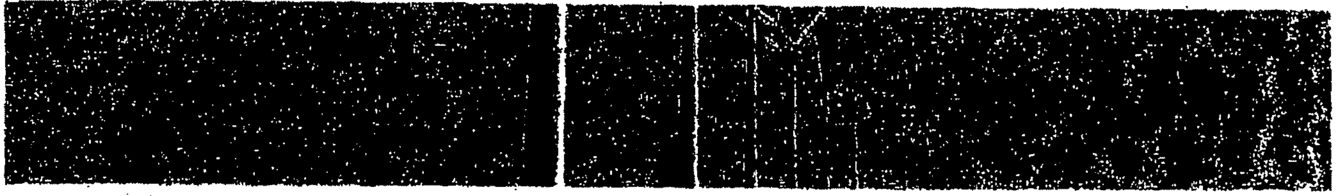
FLORIDA POWER AND LIGHT
SFHHA ADJUSTMENTS TO COMPANY PROPOSED SERVICE LIVES FOR COMBINED CYCLE GAS TURBINE UNITS
TEST YEAR ENDING DECEMBER 31, 2010
($ MILLIONS)

Source: Depreciation Study Exhibit CRC-1 Page 60 of 720 for WCEC Units 1 and 2
Depreciation Study Exhibit CRC-1 Pages 129-133 of 720 for All Other Units

Comined Cycle Units	FPL's Remaining Service Life	FPL Annual Depr	SFHHA Remaining Service Life	SFHHA Annual Depr	SFHHA Depr Reduction
West County Unit 1	25	36.032	40	22.520	(13.512)
West County Unit 2	25	30.625	40	19.140	(11.484)
Lauderdale Units 4, 5 and Common	10	25.657	25	10.263	(15.394)
Ft. Meyers Units 2, 3 and Common	18	35.040	33	19.113	(15.927)
Manatee Unit 3	20	22.551	35	12.886	(9.665)
Martin Units 3, 4, Common and Pipeline	10	25.650	25	10.260	(15.390)
Martin Unit 8	20	21.028	35	12.016	(9.012)
Putnam Units 1, 2 and Common	10	9.545	25	3.818	(5.727)
Samford Unit 4 and Common	18	22.110	33	12.060	(10.050)
Samford Unit 5 and Common	17	17.318	32	9.200	(8.118)
Turkey Point Unit 5	22	25.180	37	14.972	(10.208)
Total		270.736		146.249	(124.488)
Jurisdictional Allocation for Depreciation - Schedule C-1					0.990615
Jurisdictional Depreciation Reduction					(123.319)

Annual Accumulated Depreciation Reduction	123.319
Time Period To Apply Reduction	.5 Years
Accumulated Depreciation Reduction - Increase to Rate Base	61.660
FPL Filed Grossed Up Rate of Return	11.80%
Revenue Requirement Effect of Accumulated Depreciation Reduction	7.276
Total Revenue Requirement Effect of Capital Cost Recovery Adjustment	(116.043)

EXHIBIT___(LK-33)



Major players team up for Florida SmartMeter project

Monday, 20 April 2009 22:19

User Rating: / 0
Poor ○ ○ ○ ○ ◉ Best [Rate]

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The city of Miami announced on April 20 that it is installing a million fully-functioning smart meters for all residents within the next two years. Once carried out, the smart meter program will be the most comprehensive in the entire country.

Mayor Manny Diaz announced the plans, titled Energy Smart Miami, at a press conference hosted by Miami Dade College. The first phase, which involves the smart meter installations, will cost an estimated $200 million. Also present at the press conference were the CEOs of the major contributors to the project including Lewis Hay of Florida Power & Light (FP&L), John Chambers of Cisco, Jeffery Immelt of GE, and Scott Lang of Silver Spring Networks

"To me these are prudent and smart investments that will easily pay for themselves," said Diaz. "It will show the nation how to address environmental, energy, and economic challenges all at the same time."

The smart meters will be able to communicate wirelessly over the Internet. FP&L's customers will be able to get detailed information describing their energy usage and use it to lower their consumption, said FP&L CEO Hay.

Around 1000 consumers will get an EcoDashBoard – a central in-home energy display and control unit – that will allow for appliances and the thermostat to be controlled by the smart meter. This group of consumers will be enrolled in a demand response program that allows FP&L to adjust how appliances use energy during peak times of demand.

Across Florida the project will add Internet connectivity to power substations and other hardware along the distribution grid. Hay said that the $700 million effort will allow FP&L to prevent and quickly determine the source of power outages.

The utility is applying for a matching grant from the stimulus package that Hay says will allow FP&L to complete the project within two years. Without the funding it will take five. Around 100,000 FP&L customer in the Miami area have already been provided with smart meters that are equipped with networking technology provided by Silver Spring Networks.

Additional investments will be made to provide solar power at schools and universities and to purchase 300 plug-in electric vehicles accompanied by 50 charging stations. FP&L will have the ability to better integrate distributed renewable power sources and will be able to run the entire system efficiently.

"We have 100,000 of the meters deployed already and customers are seeing real savings," said Hay. "It's an open architecture based system that will allow new applications to be developed to automate home energy monitoring."

GE CEO Immelt said that the project will involve technologies that cover the power grid from end to end – from the power generation source to where it is consumed within the home.

"The most important word to come away with from today isn't 'green,' it's 'now,'" said Immelt. "The technologies are available now, the investments need to take place, the jobs need to be created now. This is the kind of project the country should be doing."

Mayor Diaz said that between 800 and 1000 jobs will be created and that $5 to $7 billion will be pumped into the general economy by 2016 as a result of the savings realized by consumers. Diaz added that climate concerns are at the forefront in Miami – a city that would be underwater should

the seas rise a few feet.

Cisco will be providing the network infrastructure for the project. CEO Chambers said that countries around the world are recognising the importance of investing in a smart grid.

"This is an instant replay of the Internet," said Chambers. "Instead of moving zeros and ones, we're moving electricity."

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General Electric
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Silver Spring Networks
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Redwood City, CA 94063
http://www.silverspringnet.com

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EXHIBIT___(LK-34)

FLORIDA POWER AND LIGHT
SFHHA ADJUSTMENT TO REFLECT EFFECTS OF ECONOMIC STIMULUS BILL
TEST YEAR ENDING DECEMBER 31, 2010
($ MILLIONS)

Source: Depreciation Study Exhibit CRC-1 Page 54 of 720

Economic Stimilus Expected for AMI Deployment	(20.000)
Remaining Life Depr Rate Proposed by FPL Acct 370.1 (Meters-AMI)	7.97%
Annual Depreciation Expense Reduction	(1.594)
Jurisdictional Allocation for Depreciation - Schedule C-1	0.990615
Jurisdictional Depreciation Reduction	(1.579)
Reduction to Gross Plant in Rate Base	(20.000)
Annual Accumulated Depreciation Reduction	1.579
Time Period To Apply Reduction	.5 Years
Accumulated Depreciation Reduction - Increase to Rate Base	0.790
Net Reduction to Rate Base	(19.210)
FPL Filed Grossed Up Rate of Return	11.80%
Revenue Requirement Effect of Reduction in Rate Base	(2.267)
Total Revenue Requirement Effect	(3.846)

EXHIBIT___(LK-35)

Florida Power & Light Company
Docket No. 080677-EI
SFHHA's Ninth Set of Interrogatories
Interrogatory No. 279
Page 1 of 1

Q.
Regarding Testimony of FPL Witness Barrett:

Regarding Exhibit REB-16. Please provide the 2009 budget capital expenditure information by month and provide the 2009 actual information by month for all months for which actual information is available.

A.
See Attachment No. 1.

Regarding Testimony of FPL Witness Barrett:

Regarding Exhibit REB-16. *Please provide the 2009 budget capital expenditure information by month and provide the 2009 actual information by month for all months for which actual information is available.*

2009 Approved Capital Budget

Excludes New England Division

($millions)

Business Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Power Generation	$ 22	$ 24	$ 38	$ 33	$ 35	$ 34	$ 35	$ 31	$ 41	$ 40	$ 37	$ 47	$ 417
Nuclear	53	34	64	35	83	34	34	46	30	33	63	42	533
Transmission	33	19	22	24	18	14	20	14	14	18	22	7	225
Distribution	30	31	39	32	32	31	25	31	26	24	22	22	345
Customer Service	1	0	1	1	1	2	4	3	5	8	9	10	45
Engineering & Construction and Project Development	81	74	53	82	105	96	91	91	95	102	80	85	1,034
Other	16	17	20	19	15	16	16	17	17	15	11	13	192
Total	$ 235	$ 200	$ 237	$ 225	$ 269	$ 226	$ 224	$ 234	$ 229	$241	$ 244	$ 226	$2,790

Actuals for 2009 Approved Capital Budget

Excludes New England Division

($millions)

Business Unit	Jan	Feb	Mar	Apr
Power Generation	$ 14	$ 24	$ 23	$ 32
Nuclear	24	23	38	43
Transmission	16	13	35	20
Distribution	32	28	35	30
Customer Service	0	0	0	0
Engineering & Construction and Project Development	67	26	95	50
Other *	14	13	17	16
Total	$ 167	$ 127	$ 242	$ 191

* Other for month of April excludes $83 million credit for DOE settlement relative to spent nuclear fuel storage not included in budget

2009 Approved Capital Bud

Excludes New England Division
($millions)

Business Unit		Reference Exhibit REB-18 · 2009 Approved Budget		Difference	Comment
Power Generation	$	417	$	(0)	
Nuclear		533		(0)	
Transmission		225		(0)	
Distribution		345		(0)	
Customer Service		54		(9)	During year budget transfer
Engineering & Construction and				0	
Project Development		1,025		9	During year budget transfer
Other		191		1	Net rounding differences
Total	$	2,790	$	(0)	

Actuals for 2009 Approved

Excludes New England Division
($millions)

Business Unit

Power Generation
Nuclear
Transmission
Distribution
Customer Service
Engineering & Construction and
Project Development
Other *
Total

* Other for month of April excludes

EXHIBIT___(LK-36)

FLORIDA POWER AND LIGHT COST OF CAPITAL
TEST YEAR ENDING DECEMBER 31, 2010
($ MILLIONS)

I. FPL Cost of Capital Per Filing

	Jurisdictional Adjusted Capital	Capital Ratio	Cost Rate	Weighted Avg Cost	(1) Grossed Up Cost
Long Term Debt	5,377.787	31.52%	5.55%	1.75%	1.75%
Customer Deposits	564.652	3.31%	5.98%	0.20%	0.20%
Short Term Debt	161.857	0.95%	2.96%	0.03%	0.03%
Deferred Income Tax	2,723.327	15.96%	0.00%	0.00%	0.00%
Investment Tax Credits	56.983	0.33%	9.74%	0.03%	0.03%
Common Equity	8,178.980	47.93%	12.50%	5.99%	9.79%
Total Capital	17,063.587	100.00%		8.00%	11.80%

II. FPL Cost of Capital Adjusted to Restate Common Equity and Debt Capital Structure as Recommended by Mr. Baudino

	Jurisdictional Capital Before Adjustment	Jurisdictional Adjustment	Jurisdictional Adjusted Capital	Capital Ratio	Cost Rate	Weighted Avg Cost	(1) Grossed Up Cost
Long Term Debt	5,377.787	845.038	6,222.825	36.47%	5.55%	2.02%	2.03%
Customer Deposits	564.652		564.652	3.31%	5.98%	0.20%	0.20%
Short Term Debt	161.857		161.857	0.95%	2.96%	0.03%	0.03%
Deferred Income Tax	2,723.327		2,723.327	15.96%	0.00%	0.00%	0.00%
Investment Tax Credits	56.983		56.983	0.33%	9.74%	0.03%	0.03%
Common Equity	8,178.980	(845.038)	7,333.942	42.98%	12.50%	5.37%	8.78%
Total Capital	17,063.587	-	17,063.587	100.00%		7.65%	11.07%
Incremental Grossed Up ROR							-0.74%
SFHHA Rate Base							16,511.804
SFHHA Revenue Requirement Effect							(121.424)

FLORIDA POWER AND LIGHT COST OF CAPITAL
TEST YEAR ENDING DECEMBER 31, 2010
($ MILLIONS)

II. FPL Cost of Capital Adjusted to Restate Long and Short Term Debt as Recommended by Mr. Baudino

	Jurisdictional Capital Before Adjustment	Jurisdictional Adjustment	Jurisdictional Adjusted Capital	Capital Ratio	Cost Rate	Weighted Avg Cost	(1) Grossed Up Cost
Long Term Debt	6,222.825	(438.143)	5,784.682	33.90%	5.55%	1.88%	1.89%
Customer Deposits	564.652		564.652	3.31%	5.98%	0.20%	0.20%
Short Term Debt	161.857	438.143	600.000	3.52%	2.96%	0.10%	0.10%
Deferred Income Tax	2,723.327		2,723.327	15.96%	0.00%	0.00%	0.00%
Investment Tax Credits	56.983		56.983	0.33%	9.74%	0.03%	0.03%
Common Equity	7,333.942		7,333.942	42.98%	12.50%	5.37%	8.78%
Total Capital	17,063.587	-	17,063.587	100.00%		7.59%	11.00%
Incremental Grossed Up ROR							-0.07%
SFHHA Rate Base							16,511.804
SFHHA Revenue Requirement Effect							(11.018)

IV. FPL Cost of Capital Adjusted to Add Back Company's FIN 48 Adjustment to Deferred Income Tax

	Jurisdictional Capital Before Adjustment	Jurisdictional Adjustment	Jurisdictional Adjusted Capital	Capital Ratio	Cost Rate	Weighted Avg Cost	(1) Grossed Up Cost
Long Term Debt	5,784.682		5,784.682	33.57%	5.55%	1.86%	1.87%
Customer Deposits	564.652		564.652	3.28%	5.98%	0.20%	0.20%
Short Term Debt	600.000		600.000	3.48%	2.96%	0.10%	0.10%
Deferred Income Tax	2,723.327	167.394	2,890.721	16.78%	0.00%	0.00%	0.00%
Investment Tax Credits	56.983		56.983	0.33%	9.74%	0.03%	0.03%
Common Equity	7,333.942		7,333.942	42.56%	12.50%	5.32%	8.69%
Total Capital	17,063.587	167.394	17,230.981	100.00%		7.51%	10.89%
Incremental Grossed Up ROR							-0.11%
SFHHA Rate Base							16,511.804
SFHHA Revenue Requirement Effect							(17.643)

FLORIDA POWER AND LIGHT COST OF CAPITAL
TEST YEAR ENDING DECEMBER 31, 2010
($ MILLIONS)

V. FPL Cost of Capital Adjusted to Reallocate Pro Rata Adjustments

	Jurisdictional Capital Before Adjustment	Jurisdictional Adjustment	Jurisdictional Adjusted Capital	Capital Ratio	Cost Rate	Weighted Avg Cost	(1) Grossed Up Cost
Long Term Debt	5,784.682	(176.958)	5,607.724	32.54%	5.55%	1.81%	1.81%
Customer Deposits	564.652	61.731	626.383	3.64%	5.98%	0.22%	0.22%
Short Term Debt	600.000	(4.369)	595.631	3.46%	2.96%	0.10%	0.10%
Deferred Income Tax	2,890.721	334.472	3,225.193	18.72%	0.00%	0.00%	0.00%
Investment Tax Credits	56.983	6.229	63.212	0.37%	9.74%	0.04%	0.04%
Common Equity	7,333.942	(221.105)	7,112.837	41.28%	12.50%	5.16%	8.43%
Total Capital	17,230.981	-	17,230.981	100.00%		7.32%	10.60%
Incremental Grossed Up ROR							-0.29%
SFHHA Rate Base							16,511.804
SFHHA Revenue Requirement Effect							(48.695)

VI FPL Cost of Capital Adjusted to Increase ADIT for Depreciation Changes

	Jurisdictional Capital Before Adjustment	Jurisdictional Adjustment	Jurisdictional Adjusted Capital	Capital Ratio	Cost Rate	Weighted Avg Cost	(1) Grossed Up Cost
Long Term Debt	5,607.724		5,607.724	32.38%	5.55%	1.80%	1.80%
Customer Deposits	626.383		626.383	3.62%	5.98%	0.22%	0.22%
Short Term Debt	595.631		595.631	3.44%	2.96%	0.10%	0.10%
Deferred Income Tax	3,225.193	88.180	3,313.373	19.13%	0.00%	0.00%	0.00%
Investment Tax Credits	63.212		63.212	0.36%	9.74%	0.04%	0.04%
Common Equity	7,112.837		7,112.837	41.07%	12.50%	5.13%	8.39%
Total Capital	17,230.981	88.180	17,319.161	100.00%		7.28%	10.54%
Incremental Grossed Up ROR							-0.05%
SFHHA Rate Base							16,511.804
SFHHA Revenue Requirement Effect							(8.909)

FLORIDA POWER AND LIGHT COST OF CAPITAL
TEST YEAR ENDING DECEMBER 31, 2010
($ MILLIONS)

II. FPL Cost of Capital Adjusted to Restate ROE at 10.4% as Recommended by Mr. Baudino

	Jurisdictional Capital Before Adjustment	Jurisdictional Adjustment	*Jurisdictional* Adjusted Capital	Capital Ratio	Cost Rate	Weighted Avg Cost	(1) Grossed Up Cost
Long Term Debt	5,607.724		5,607.724	32.38%	5.55%	1.80%	1.80%
Customer Deposits	626.383		626.383	3.62%	5.98%	0.22%	0.22%
Short Term Debt	595.631		595.631	3.44%	2.96%	0.10%	0.10%
Deferred Income Tax	3,313.373		3,313.373	19.13%	0.00%	0.00%	0.00%
Investment Tax Credits	63.212		63.212	0.36%	9.74%	0.04%	0.04%
Common Equity	7,112.837		7,112.837	41.07%	10.40%	4.27%	6.98%
Total Capital	17,319.161	-	17,319.161	100.00%		6.42%	9.13%
Incremental Grossed Up ROR							-1.41%
SFHHA Rate Base							16,511.804
SFHHA Revenue Requirement Effect							(232.610)

FLORIDA POWER AND LIGHT COST OF CAPITAL
TEST YEAR ENDING DECEMBER 31, 2010
($ MILLIONS)

VIII. FPL Cost of Capital Adjusted to Restate Short Term Debt Rate as Recommended by Mr. Baudino

	Jurisdictional Capital Before Adjustment	Jurisdictional Adjustment	Jurisdictional Adjusted Capital	Capital Ratio	Cost Rate	Weighted Avg Cost	(1) Grossed Up Cost
Long Term Debt	5,607.724		5,607.724	32.38%	5.55%	1.80%	1.80%
Customer Deposits	626.383		626.383	3.62%	5.98%	0.22%	0.22%
Short Term Debt	595.631		595.631	3.44%	0.60%	0.02%	0.02%
Deferred Income Tax	3,313.373		3,313.373	19.13%	0.00%	0.00%	0.00%
Investment Tax Credits	63.212		63.212	0.36%	9.74%	0.04%	0.04%
Common Equity	7,112.837		7,112.837	41.07%	10.40%	4.27%	6.98%
Total Capital	17,319.161	-	17,319.161	100.00%		6.34%	9.05%

Incremental Grossed Up ROR	-0.08%
SFHHA Rate Base	16,511.804
SFHHA Revenue Requirement Effect Before Adding Back Facility and Administrative Fees	(13.446)
Facility and Administrative Fees Added to Revenue Requirement as Interest Expense	1.661
Net SFHHA Revenue Requirement Effect	(11.785)

(1) Grossed up costs include effects of federal and state income taxes, bad debt expense and regulatory assessment fee found on Schedule C-44.

Federal Income Tax Rate	35.00000%
State Income Tax Rate	5.50000%
Bad Debt	0.00260%
Regulatory Assessment Fee	0.00072%

EXHIBIT___(LK-37)

Q.

Regarding Schedule D-1A for the 2010 test year. Please provide the FIN 48 net ADIT amount, by temporary difference, included in each of the ADIT amounts for the Company total per books, specific adjustments, system adjusted and jurisdictional adjusted. If these amounts cannot be provided by temporary difference due to privilege concerns, then provide the net aggregate amount. Positive signs should indicate asset ADIT amounts and negative signs should indicate liability ADIT amounts.

A.

For the 2010 test year, there was no forecast made applicable to changes in the temporary differences for which a FIN 48 uncertain tax positions had been recognized in prior periods. As of the end of December 2008, the total Accumulated Deferred Tax Liabilities for which FIN 48 liability was recognized was $168,598,172. Since uncertain tax positions relate to future potential liabilities, the deferred taxes associated with the temporary differences related to the FIN 48 liabilities were included in the accumulated deferred income taxes in the capital structure, rather than including them with long-term liabilities in rate base. This presentation is consistent with the treatment of the deferred taxes and FIN 48 liabilities established for FERC reporting. There were no FIN 48 uncertain tax positions related to any Accumulated Deferred Tax Assets.

EXHIBIT___(LK-38)

Florida Power & Light Company
Docket No. 080677-EI
SFHHA's Ninth Set of Interrogatories
Interrogatory No. 280
Page 1 of 1

Q.
Regarding Testimony of FPL Witness Pimentel:

Regarding page 13:14-20. Regarding the Company's credit facility and available loan term, please provide a more detailed description of each source, including, but not limited to, the pricing terms, duration, and other terms.

A.
On April 3, 2007, FPL renewed the credit facility of $2.5B with participation from 38 banks, expiring in April, 2012. It was subsequently extended an additional year to expire in 2013, with the exception of $17M expiring in 2012. On May 28, 2009, the credit facility was revised to exclude the participation of Lehman Brothers. Currently the credit facility size is $2.473B. In addition, FPL has a $250M term loan facility expiring in May, 2011. There are currently no borrowings outstanding under either facility

The annual costs for the credit facility are $1,535,938. This includes an annual facility fee of 4.5 basis points ($1,125,000) and annual amortization of upfront commitment, arrangement and administrative fees paid in the amount of $410,938. The annual costs for the term loan facility are $125,000 for facility fees.

In the event that FPL would borrow against the credit facility the interest charged is dependent on FPL's credit ratings and priced as a spread over LIBOR.

CERTIFICATE OF SERVICE
DOCKET NO. 080677-EI

I HEREBY CERTIFY that a copy of the **PREFILED TESTIMONY AND EXHIBITS OF THE SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION** has been furnished by electronic mail and U.S. mail to the following parties on this 16th day of July, 2009 to the following:

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<u>/s/ Kenneth L. Wiseman</u>
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March 2, 2002

Via Federal Express

Ms. Blanca S. Bayo, Director
Division of the Commission Clerk
and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: *Review of the Retail Rates of Florida Power & Light Company, Docket No. 001148-EI*

Dear Ms. Bayo:

On behalf of the South Florida Hospital and Healthcare Association ("SFHHA"), enclosed please find:

(1) an original and 15 copies of the Prepared Direct Testimony and Exhibits of Stephen J. Baron; and 02471-02

(2) an original and 15 copies of the Public Version of the Prepared Direct Testimony and Exhibits of Lane Kollen. 02472-02

Please acknowledge receipt and filing of the above by stamping the duplicate copy and returning same in the enclosed self-addressed stamped envelope to the undersigned.

Additionally, in a separate overnight package, we have served you with a Confidential version of Lane Kollen's Prepared Direct Testimony, a copy of which also is being served upon FPL.

Thank you for your assistance in connection with this matter.

Very truly yours,

Mark F. Sundback

Mark F. Sundback
Kenneth L. Wiseman
Attorneys For the Hospitals

AUS ___
CAF ___
CMP ___
COM ___
CTR ___
ECR ___
GCL ___
OPC ___
MMS ___ Enclosures
SEC 1 cc: Counsel for Parties of Record
OTH ___

92426-1

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

Re:	Review of the Retail Rates of Florida Power & Light Company	))	Docket No. 001148-EI

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

February 2002

PUBLIC VERSION

WAS:92424.1

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

Re:	**Review of the Retail Rates of Florida Power & Light Company**	))	**Docket No. 001148-EI**

TABLE OF CONTENTS

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

Re:	**Review of the Retail Rates of Florida Power & Light Company**	**)** **)**	**Docket No. 001148-EI**

DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree from the University of Toledo. I also earned a Master of Business Administration degree from the University of Toledo. I am a Certified Public Accountant, with a practice license, and a Certified Management Accountant.

I have been an active participant in the utility industry for more than twenty years, both as an employee and as a consultant. Since 1986, I have been a consultant with Kennedy and Associates, providing services to state government agencies and large consumers of utility services in the ratemaking, financial, tax, accounting, and management areas. From 1983 to 1986, I was a consultant with Energy Management Associates, providing services to investor and consumer owned utility companies. From 1978 to 1983, I was employed by The Toledo Edison Company in a series of positions encompassing accounting, tax, financial, and planning functions.

I have appeared as an expert witness on accounting, finance, ratemaking, and planning issues before regulatory commissions and courts at the federal and state levels on more than one hundred occasions. I have developed and presented papers at various industry conferences on ratemaking, accounting, and tax issues. I have testified before the Florida Public Service Commission in Docket Nos. 870220-EI (Florida Power Corp.), 8800355-EI (Florida Power & Light), 881602-EU and 890326-EU (City of Tallahassee), 890319-EI (Florida Power & Light), 910840-PU (Generic Proceeding Re SFAS 106), 910890-EI (Florida Power Corp.), and 920324-EI (Tampa Electric

Company). My qualifications and regulatory appearances are further detailed in my Exh.___(LK-1)).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the South Florida Hospital and Healthcare Association ("SFHHA")

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address several revenue requirement issues, including the revenue refund included by the Company in the test year relating to the effects of the Rate Agreement in prior years; the special depreciation allowed pursuant to the Commission's Order in Docket 990067-EI; further depreciation effects on the Company's nuclear units of license renewals (life extensions) of 20 years; deferred pension debit included by the Company in working capital; storm damage expense, reserve, and funding; projected growth in operation and maintenance expense; capitalization structure. I also discuss matters associated with FPL's capital additions.

Q. Please summarize your testimony.

A. I recommend that the Commission reduce the Company's revenue requirement by at least $475 million based upon the following adjustments.

Remove the revenue refund due to the effects of the 1999 Rate Agreement. ($34.086 million reduction).

Reduce depreciation expense to reflect Turkey Point 3 and 4 and St. Lucie 1 and 2 20-year service life extensions. ($77.485 million reduction).

Amortize the special nuclear and fossil depreciation allowed pursuant to 1999 Rate Agreement over three years. ($53.574 million reduction).

Remove the deferred pension debit included by the Company in working capital. ($62.873 million reduction).

Eliminate increase in storm damage expense. ($30.315 million reduction)

Reflect rate of return based upon internal funding of storm damage reserve treated as rate base reduction. ($31.099 million reduction).

Reduce projected growth in operation and maintenance expense, excluding the proposed increase in storm damage expense from 9.2% to 4.6%. ($47.432 million reduction).

Adjust overall return for accumulated deferred income tax effects of rate base adjustments. ($34.140 million increase)

Limit the common equity in the capitalization structure to 50%, quantified on a traditional basis. ($172.545 million reduction).

II. REFUND DUE TO RATE AGREEMENT

Q. Please describe how the Company has reflected its projection of the refund in the 2002 test year related to the 1999 Rate Agreement.

A. The Company has reflected a $34.086 million projection of the refund for prior years pursuant to the 1999 Rate Agreement as a permanent adjustment (reduction) to existing and ongoing base rate tariff levels.

Q. Should the Commission make an adjustment to remove this refund amount from test year operating income?

A. Yes. This refund amount does not reflect a permanent adjustment to existing and ongoing base rate tariff levels. Test year operating income should reflect the existing and ongoing base rate tariff levels without refunds related to prior periods. As such, the projected $34.086 million refund should be taken out of operating income on a pro forma basis.

Q. Why is the refund not a permanent feature?

A. The arrangement under the 1999 Rate Agreement expires in the spring of 2002. Thus the revenue-sharing threshold under which the refund will arise will not apply to revenue levels once the 1999 Rate Agreement is no longer effective.

III. DEPRECIATION AND AMORTIZATION

Depreciation on Turkey Point 3 & 4 and St. Lucie 1 & 2

Q. What service life is reflected currently in the depreciation rates for the Turkey Point 3 and 4 and St. Lucie 1 and 2 nuclear units?

A. The depreciation rates most recently authorized by the Commission for these nuclear units reflect service lives of 40 years. These service lives were based upon the 40-year terms of the initial NRC operating licenses for the units.

Q. Have there been recent changes in the expected service lives of the nuclear units?

A. Yes. FPL has applied for 20 year operating license extensions for the two Turkey Point units and the two St. Lucie units.

Q. Has the NRC ever refused to extend the operating license for any nuclear unit to date?

A. No.

Q. Why should the Commission reflect the additional 20-year service lives of the units for depreciation expense purposes in this proceeding?

A. First, absent any reliable documentation to the contrary, the Company clearly plans to operate these nuclear units for as long as it is physically and economically possible to do so. In fact, the Company cited such economic benefits to ratepayers as the rationale for applying for license extensions on the Turkey Point units. The Company stated in its 2000 Annual Report to Shareholders the following:

> To ensure that customers continue to receive the economic and environmental benefits provided by Turkey Point, FPL in 2000 submitted an application to the Nuclear Regulatory Commission to extend the plant's operating license an additional 20 years until 2033.

The Company has also prepared studies that demonstrate life extension is economic and will provide benefits to ratepayers.

If the Company did not believe that extending the units' lives through the license renewal process was physically possible and economically viable, based upon the facts currently known and knowable, then it would have been imprudent for it to incur the significant costs to extend the operating licenses. Thus, the best evidence of the service lives of these units is the Company's current intent to continue to operate them for an additional 20 years beyond the initial license terms.

Second, the existing depreciation rates are excessive because they provide for rate recovery of the capital costs of the units over 40 year service lives rather than the expected 60-year service lives. The mismatch between service lives and recovery creates intergenerational inequities among ratepayers. The existing depreciation rates and the ratemaking process provide for current and future recovery of plant additions, including those that may be necessary to assure the continued operation of the plants throughout their initial 40 years service lives as well as the additional 20 years.

Third, changing the depreciation rates will have a direct and immediate effect on the rates otherwise charged to ratepayers as the result of this proceeding. If the depreciation rates are changed subsequent to this proceeding, then the reduced expense will redound to the benefit of FPL's parent company, FPL Group, unless and until base rates are again reset. If the Commission waits until the Company files another depreciation study, even assuming FPL reflects the service life extensions in that depreciation study, it is unlikely ratepayers will receive a direct and immediate rate reduction coinciding with the Commission's adoption of new depreciation rates.

Q. Is there another reason to act on this issue in this rate case?

A. Yes. If power prices are deregulated and the electric industry in Florida is restructured without fixing this problem, FPL will experience a windfall – in essence, twenty years' use of large generating units with effectively no capital investment left. This will distort competition and means that ratepayers will have subsidized FPL unnecessarily.

Q. Did the Georgia Public Service Commission recently approve a reduction in the depreciation rates for Hatch 1 and 2 and Vogtle 1 and 2 based upon Georgia Power Company's application to extend the operating licenses for the Hatch units and its intent to do so for the Vogtle units?

A. Yes. In December 2001, that Commission approved significantly lower depreciation rates for the Hatch 1 and 2 nuclear units reflecting 20-year operating life extensions. The decision was based upon then pending Georgia Power Company applications before the NRC for 20-year license renewals. In January 2002, the NRC approved the applications for Hatch 1 and 2, thereby renewing their operating licenses for an additional 20 years.

In addition, the Georgia Public Service Commission approved depreciation rates that reflected 10-year service life extensions for the Vogtle 1 and 2 nuclear units. That decision was based upon Georgia Power Company's stated intent to apply for 20-year license renewals on those units as soon as possible in accordance with the NRC's procedural schedule for such license renewals.

Q. Have you quantified the effect of extending the service lives by 20 years for Turkey Point 3 and 4 and St. Lucie 1 and 2?

A. Yes. The effect is to reduce the Company's MFR revenue requirement by $77.485 million. This quantification reflects a reduction in depreciation expense of $83.000 million and a related reduction in accumulated depreciation for the test year of $41.500 million, but excluding the offsetting deferred tax effect reflected in the overall return applied to rate base.

<u>Amortization of Special Depreciation</u>

Q. Please describe the special depreciation authorized by the Commission in conjunction with its approval of a Stipulation and Settlement in Docket No. 990067-EI.

A. FPL was authorized to record up to an additional $100 million annually, over a three-year period, in special depreciation to reduce its nuclear and/or fossil production plant in service. The Company has recorded $170.250 million in such special depreciation.

Q. How has the Company reflected the special depreciation in its filing in this proceeding?

A. The Company has reflected this special depreciation as a reduction to rate base in this proceeding, but has reflected no amortization of this amount in operating income.

Q. Should the Commission amortize the special depreciation amount to the benefit of ratepayers in this proceeding?

A. Yes. There is no valid reason for the Commission simply to perpetuate this temporary overrecovery only as a rate base reduction, and with no amortization, going forward. The Company was allowed to accumulate the special depreciation in lieu of rate reductions for excess earnings during the effective period of the 1999 Rate Agreement. The Company has reflected the full amount of this special depreciation as a rate base reduction in its filing in this proceeding. As such, there is no dispute as to whether the special depreciation is attributable to, and thus belongs to, the ratepayers. However, the Company's filing provides for no return of this overrecovery to ratepayers. The Commission ultimately will have to make a determination as to the disposition of this overrecovery, preferably in this docket. Unless the Commission acts to amortize this amount, then the special depreciation will result in an accumulated depreciation reserve that exceeds the cost of the Company's existing plant and projected dismantlement costs. Perhaps recognizing the inequities of a similar situation in a previous docket, the Commission authorized the amortization of another special depreciation amount over the remaining life of the underlying nuclear assets.

Q. What amortization period should the Commission utilize to return the special depreciation to ratepayers?

A. A three-year amortization period would be appropriate. The special depreciation was recovered from ratepayers over the three-year term of the 1999 Rate Agreement. It should be returned over a comparable period. In this manner, it is more likely that the those ratepayers that paid the excess revenues for the special depreciation will be the beneficiaries of the return of those revenues.

Q. Have you quantified the effect on the revenue requirement of a three-year amortization of the special depreciation?

A. Yes. A three-year amortization would reduce the revenue requirement by $53.574 million. The amortization expense would be negative $56.750 million and rate base would increase by $28.375 million, assuming a uniform amortization throughout the test year, and excluding the offsetting deferred tax effect reflected in the overall return applied to rate base.

IV. DEFERRED PENSION DEBIT

Q. Please describe the deferred pension debit included by the Company in its cash working capital computation.

A. The Company has included a deferred pension debit in working capital. This asset represents the cumulative effect of the Company's net pension income (negative pension expense) since 1994 as detailed in its response to SFHHA Interrogatory #42, which I have replicated as my Exh.___(LK-2).

Q. Should the deferred pension debit be included in cash working capital as a conceptual matter?

A. No. The inclusion of this asset in rate base would require ratepayers to pay a carrying charge on an asset representing the cumulative effect of pension income amounts recognized and retained by FPL during the years 1994-2001. The benefits of the pension income during those years was not provided to ratepayers in the form of rate reductions. Instead, the rates in effect during those years, but for the limited reductions due to the 1999 Rate Agreement, reflected the recovery from ratepayers of positive pension expense based upon the test year levels in Docket No. 830465-EI. Thus, the elimination of the pension expense and the recognition of pension income were "savings" benefits retained by the Company's shareholder, FPL Group. As such, any carrying costs on the deferred pension debit amount accumulated through 2001, assuming there are any, should be attributed to FPL and its shareholder, and not to ratepayers.

Q. To the extent that pension income actually is flowed through to ratepayers, is it appropriate to reflect the related deferred pension debit in rate base?

A. Yes. In the test year, the Company has reflected pension income in operating income. Thus, the average balance of the test year pension income should be reflected in rate base.

Q. Have you quantified the effect of removing the deferred pension debit from rate base?

A. Yes. The removal of the deferred pension debit from rate base for the 1994-2001 period results in a revenue requirement reduction of $62.873 million, excluding the offsetting deferred tax effect reflected in the overall return applied to rate base.

V. STORM DAMAGE EXPENSE, RESERVE, AND FUNDING

Q. Please describe the Company's request for storm damage expense and funding treatment.

A. The Company has requested an increase in storm damage expense from the currently authorized level of $20.3 million to $50.3 million in conjunction with its request for an increase in the reserve level from $234 million to a target of $500 million. The Company has funded the storm damage reserve, which is managed by an FPL Group affiliate. As such, the large amount of reserve balance has not been utilized to reduce rate base in the Company's filing, unlike the Company's other reserve balances that are not funded and instead are utilized to reduce rate base.

Q. If the storm damage reserve balance is not utilized to reduce rate base, then how are ratepayers compensated for the use of their money?

A. Unfortunately, the Company's filing reflects no compensation to ratepayers for the use of their money. There not only is no rate base reduction, there also is no reduction in the requested $50.3 million annual expense to reflect earnings on the trust fund the Company has established.

Q. Under the traditional regulatory cost recovery model, are ratepayers compensated for their money either through a return offset on trust fund earnings or through a rate base reduction?

A. Yes. The failure to reflect an earnings offset of any sort to the requested accrual is unlike the return (earnings) offset recognized in the quantifications of pension expense, postretirement benefits other than pensions expense, and decommissioning expense, all of which accumulate amounts in dedicated trust funds similar to the funded reserve approach employed by FPL for storm damage expense. Other advances by ratepayers not included in trust funds are reflected as rate base reductions, including accumulated deferred income taxes.

Q. Should the Commission increase the storm damage expense amount?

A. No. First, increasing the storm damage expense will only exacerbate the disconnect between expense accruals and actual costs. By virtue of the fact that there is already a substantial storm reserve balance, the Company has been provided excessive storm damage expense recovery in prior years. Expense accruals have exceeded actual costs.

Second, the Commission should reject the Company's conclusory rationale that it is necessary to prepay storm damage costs in anticipation of a possible catastrophic loss exceeding the existing reserve level, and allow FPL to deprive ratepayers of time value of their substantial funds. In effect, this rationale is no different than if the Company had requested that ratepayers prepay the costs of the various generating plant repowerings in which it is engaged. While such prepayments may result in lower financing costs for FPL, they result in higher costs to ratepayers through current rates and intergenerational inequities.

In fact, the inequity of the intergenerational affect is driven home by information FPL produced in response to SFHHA in discovery. FPL's response to SFHHA Interrogatory No. 123 shows that for FPL's Southeastern region, the number of years between expected occurrences of hurricanes ranges from a low of 16 years for hurricanes at the SSI 3 level to 250 years for hurricanes at the SSI 5 level. For FPL's western region, the number of years between expected occurrences of hurricanes ranges from a low of 30 years for SSI 1 hurricanes to over 500 years for SSI 5 hurricanes. For FPL's Northeastern region, the number of years between expected occurrences of hurricanes ranges from a low of 36 years for SSI 1 hurricanes to 500 years for SSI 5 hurricanes. FPL's interrogatory response providing this information is reproduced as my Exh.___ (LK- 3). Thus, the information FPL provided shows an expectation that if FPL's proposal is approved, today's ratepayers will be paying for storm damages that may not be suffered for generations to come.

Q. But what are the expected annual damages for hurricanes at each of the storm intensity levels (*i.e.*, SSI 1 through SSI 5)?

A. FPL has no analysis on that issue. *See* Exh. ___ (LK- 4) (FPL Interrogatory Response No. 124).

Q. Are there other reasons why the requested increase in the storm fund should be rejected?

A. Yes. The request for the additional $30 million in storm fund amounts seems to ignore federal and state funds available in the event of natural disasters and catastrophic losses. Such funds would serve to reduce the costs associated with catastrophic losses.

Additionally, there is no indication that the Company could not finance and subsequently recover from ratepayers any costs related to a catastrophic loss above and beyond existing reserve levels and government emergency assistance. To the contrary, the Company does have plans in place to finance such costs if such a catastrophic loss should occur. In addition, the Company historically has been able to recover its storm damages costs from ratepayers, even if the reserve temporarily is depleted or negative.

Further, the Company's request fails to incorporate earnings on the trust fund and is overstated for that reason alone. The Commission should incorporate earnings on the trust fund in order to determine the net accrual necessary. For example, if the Commission believes that a $40 million annual accrual is appropriate, then that amount should be reduced for the earnings on the trust fund. At a 10% rate of return, applied to the existing $234 million balance, the net expense requirement would be only $17 million ($40 million less $23 million).

Q. Is the Company's approach to fund the storm damage reserve the most economic from the perspective of the ratepayers?

A. No. First, the earnings of the trust fund apparently inure to the benefit of the Company, not ratepayers. Although the earnings on the trust fund are added to the trust fund balance, the existing and proposed expense accruals have not been reduced for trust fund earnings.

Second, the trust fund earnings historically have been significantly below the Company's last authorized and requested rates of return. In other words, ratepayers would be far better off if the Company utilized these prepayments to invest in plant and equipment by displacing other required financing and reflected the prepayments as a reduction to rate base similar to the Company's other reserves. The trust fund has averaged an after tax return of only 4.5% over the last 5 years compared to its last authorized rate of return of 10.40% and its test year MFR rate of return in this proceeding of 8.97%. The average return earned by the Company on the storm damage trust fund over the last 5 years is detailed in the Company's response to SFHHA Interrogatory # IV-38, a copy of which I have replicated as my Exh.___(LK-5) along with my computations of the average return over the last 5 years.

Q. What would be the impact if the trust fund had earned an after tax rate of return comparable to that reflected in the MFR filing in this proceeding rather than the 4.5% it actually earned?

A. The trust fund balance would be in excess of $300 million for the test year, compared to the existing $234 million balance cited by the Company in its testimony.

Q. What would the trust fund's balance be three years from now if that MFR-level return continued along with the historic pattern of withdrawals?

A. Nearly $400 million.

Q. What is your recommendation regarding the Company's funding of the storm damage reserve?

A. I recommend that the Commission reflect the storm damage reserve as a rate base reduction in the same manner as it reflects other reserve amounts representing prepayments by ratepayers. This is the least cost financing option for ratepayers. If the Company dissolves the trust fund, then presumably it could utilize the funds to displace existing or future financing consistent with its overall rate of return requirements.

Q. Should the Commission ensure that ratepayers are provided a return on their money provided to the Company for storm damage expenses in advance of the Company's payments for such expenses, regardless of the level of storm damage expense authorized by the Commission in this proceeding?

A. Yes. I recommend that the Commission reflect the return effects directly by utilizing the reserve balance as a reduction to rate base. Alternatively, the Commission could reflect the return as a reduction to the expense accrual that it otherwise finds to be appropriate.

Q. Have you quantified the effect of your recommendations on storm damage expense, reserve, and funding?

A. Yes. The effects of my recommendations are to reduce the revenue requirement by $61.414 million. The revenue requirement effect includes a reduction in storm damage expense of $30.000 million, the increase sought by the Company, and reflects a rate base reduction for the Company's $234 million reserve balance.

VI. OPERATION AND MAINTENANCE EXPENSE

Q. Please describe the increase in O&M expense sought by the Company in this proceeding.

A. The Company's revenue requirement projection for 2002 includes an increase of $123.879 million (jurisdictional) in O&M expense for the test year over the MFR estimate of $1,021.911 million (jurisdictional) for 2001. The increase is $30.000 million less once the Company's requested increase in storm damage expense is removed. Nevertheless, the increase sought by the Company exceeds 12.12% including the increase to storm damage expense and 9.19% excluding the increase to storm damage expense.

Q. How does the Company's request compare to the actual growth in O&M expense in prior years?

A. The Company's request is excessive compared to its actual experience. The following table provides a history of the Company's O&M expenses and the annual percentage increase or decrease.

FLORIDA POWER & LIGHT COMPANY NON-FUEL O&M EXPENSE		
	$Million	% Change
1995	1,138	na
1996	1,127	-0.99%
1997	1,132	0.44%
1998	1,163	2.74%
1999	1,089	-6.36%
2000	1,062	-2.48%
	Average % Change	-1.33%

In addition to reducing its O&M expense in absolute dollars, the Company has reduced its O&M expense on a cents per kWh basis for the last 11 consecutive years, a fact that it cites in support of its claim that it is focused on controlling its costs and improving its efficiencies.

Q. Historically, how does the Company's actual O&M expense compare to its budget amounts?

A. Historically, the Company's actual O&M expense has been less than its budget amounts. In 2000, the Company's actual O&M expense was $999 million compared to budget (plan) of $1,034 million. In 1999, the Company's actual O&M expense was $1,026 million compared to budget of $1,072 million. In 1998, the Company's O&M expense was $1,088 million compared to budget of $1,090 million. The Company provided these comparisons in response to SFHHA Interrogatory # V-57, which I have replicated as my Exh.___(LK- 6).

Q. Did the Company revise its O&M expense downward in conjunction with its revision downward of revenues?

A. No. Instead of a reduction in O&M compared to the Company's budget for 2002, relied upon for its initial MFR filing, the Company claimed an increase in O&M of $22.640 million when it subsequently revised certain MFR schedules.

Once again, the failure to reduce downward its O&M expense is a complete disconnect from reality, not only based upon FPL's history, but also based upon business requirements in the unregulated world. First, FPL is focused on reducing its O&M expense per kWh, a statistic it cites in public forums as evidence of its excellent management. If projected sales are reduced and O&M expense is not, then the projected O&M expense per kWh will rise compared to the 11 prior years of reductions.

Second, FPL should not be held to a lower standard of cost control in response to projected lower sales, but rather to a higher standard. It is only logical that if revenues are lower for purposes of the rate filing compared to the Company's budget, then it also should be required to reflect commensurate reductions in its O&M expense for purposes of the rate filing compared to its budget.

Q. Please respond to the claim by Company witness Mr. Shearman that the Company will not be able to sustain its enviable historic reductions in O&M expense into 2002 and 2003 due to "inflation, aging assets, customer growth, and load growth.

A. There is not a shred of logical support for such an assertion. First, inflation currently is nearly nonexistent. Second, the Company's capital expenditures for new and replacement plant approximate 15% of its asset base every year. This is evidence of relatively new, and more likely, lower maintenance plant. Some of those capital expenditures undoubtedly were incurred to reduce O&M expense and are reflected in rate base. Ratepayers should be provided the full benefit of the related expense reductions.

Third, customer growth and load growth obviously overlap quite a bit. As noted earlier, to the extent that such growth is projected to be lower, as reflected in the Company's revised revenue forecast, then O&M expense should have been reduced as well, not increased. Finally, it should be noted that the Company voluntarily determined to increase its reserve margin from the Commission's mandated 15% to 20% and to accelerate its scheduled capacity additions and repowerings. Thus, at least to some extent, the related O&M expense also is discretionary. Presumably, the Company should recover such discretionary increased costs through higher interchange revenues, particularly given its projection of little or no growth in its customer base.

Finally, the FPL Group 2000 Annual Report to Shareholders directly rebuts the substance of Mr. Shearman's arguments in favor of higher O&M expense growth. The Company cites its ability actually to reduce O&M expense in the face of customer and load growth and describes the addition of significant generation capacity (new plant compared to the aging plant cited by Mr. Shearman). The relevant excerpt from that Annual Report follows.

> Since 1990, when the company was restructured, FPL has driven down costs while achieving continuous improvements in virtually every area of its operations. At the same time, it has taken steps to meet the sharply increasing energy demands of a service area that continues to grow at a rapid pace.
>
> FPL's customer base grew by 2.5% in 2000 to more than 3.8 million. More new customers, 92,000, were added than in any year since 1990. In addition, energy usage per customer increased by nearly 2% over the previous year.
>
> In 2000, FPL reduced its operations and maintenance costs per kilowatt-hour for the tenth consecutive year. Since 1990, O&M costs have declined 40% - from 1.82 cents per kilowatt-hour to 1.09 cents. During this time the company added more than 700,000 new customer accounts and increased its generating capacity by 24%.
>
> FPL's cost reduction efforts have resulted in a more efficient and productive organization and enabled the company to hold down the price of its electricity to below the national average.
>
> FPL continues to achieve major improvements in such critical success areas as plant performance, electric reliability, and customer service.

Thus, it appears that FPL does not share Mr. Shearman's views regarding its ability to reduce O&M expense given the same factors cited in his testimony.

Q. Did Mr. Shearman investigate whether FPL's efforts to reduce costs during 1999-2001 caused costs to increase following 2001?

A. No. Apparently he made no effort to determine whether that had occurred. Of course, during the 1999-2001 period, FPL might retain all of the savings resulting from deferring costs. Mr. Shearman also did not investigate how FPL's profits may have been increased during 1999-2001, due to such cost reductions. See my Exh.___ (LK-7).

In contrast, FPL had no assurance that it would retain any cost savings following March 31, 2002, and any costs that could be deferred into that period could help justify higher rates.

Q. Are Mr. Shearman's comparisons meaningful?

A. Not really. He ignored many different variables between utilities that tend to affect costs and thus he is unable to make apples to apples comparisons.

Q. Did his various exhibits take into account varying ages of generation fleets, which would affect outage levels and O&M cost levels?

A. No. Exh.____ (LK-8).

Q. Did his various exhibits take into account the differences in types of generators, since (for instance) different types of nuclear reactors have different maintenance issues?

A. No. Exh.___ (LK-9).

Q. What reasonably can be concluded regarding the Company's projected growth in O&M expense given its historic O&M expense growth and its public statements regarding controlling costs and improving efficiencies?

A. The Company's O&M expense projected for the test year is excessive. The Commission should look to history as a guide to the reasonable and necessary level of O&M expense and the Company's ability to control the actual level of expense compared to the amounts reflected in its filing in this proceeding.

Q. What is your recommendation?

A. Absent more definitive data or a more conclusive showing of actual O&M levels, I recommend that the Commission limit the growth in O&M expense for the test year to at most half of the Company's projection, excluding the increase due to storm damage expense. This recommendation reflects a 4.60% increase in O&M expense compared to 2001, excluding the proposed increase in storm damage expense, still an exceptionally high level compared to recent experience of negative growth.

VII. CAPITALIZATION STRUCTURE

Q. Please describe the Company's proposed capitalization structure.

A. The Company has proposed the following capitalization structure computed on a financial statement basis, excluding accumulated deferred income taxes, which are included in capitalization only as a ratemaking convention in lieu of subtraction from rate base.

FLORIDA POWER & LIGHT COMPANY
CAPITALIZATION STRUCTURE

	$Million	%Capital
Long Term Debt	2,809	32.7%
Short Term Debt	52	0.6%
Preferred Stock	227	2.6%
Common Equity	5,505	64.1%
Total	8,593	100.0%

Q. Is the level of common equity included in the Company's proposed capitalization structure excessive?

A. Yes. It is excessive for an A rated utility coupled with the lower level of risk experienced by FPL as a regulated utility compared to FPL Group and its unregulated business activities. FPL's bond ratings and investor risk perceptions are strongly influenced by FPL Group's extensive unregulated business activities. This higher level of unregulated risk results in higher costs that should not burden FPL's ratepayers.

Q. What has Standard and Poor's stated regarding the FPL Group unregulated activities risk and the effect on FPL?

A. First, S&P rates utility debt on the basis of the parent company's consolidated fundamentals, not solely on the utility company's business and financial risk. S&P stated in a recent commentary posted on its website the following:

> [U]tilities that merge with other companies and invest outside the traditional regulated businesses will be rated on the basis of the qualitative and quantitative fundamentals of their consolidated entities.

Second, prior to the downrating of FPL from AA- to A, S&P issued its rationale for the its negative creditwatch and stated the following in the wake of the announcement of the proposed FPL-Entergy merger.

> The ratings on Florida Power & Light Co., the utility operating company of FPL Group Inc., are on CreditWatch with negative implications, reflecting FPL Group's announced merger with lower-rated Entergy Corp.
>
> * * * *
>
> Despite the utility's stellar financials, the consolidated entity is challenged to improve consolidated credit-protection measures as the firm expands its portfolio of independent power projects.
>
> Florida Power & Light's corporate credit rating is based on the financial and business risk profile analysis of the consolidated enterprise, derived by analyzing each individual core-operating unit. There are insufficient prescriptive regulatory measures to restrict cash flow from the utility to the parent.
>
> Florida Power & Light's first mortgage bonds are rated the same as the firm's corporate credit rating.

In reviewing FPL and its affiliates, Standard & Poor's noted FPL's "buoyant cash flow" and "strong business profile" "tempered by the growing portfolio of higher-risk nonregulated investments, principally in independent power projects . . . ." Particularly, in reviewing the growth plans of the FPL Group, the report stated that "Standard & Poor's views the business risk profile of independent power producers at the high end of the risk spectrum . . . ." FPL Group's energy marketing and trading operation was characterized as a "high-risk business segment."

More recently, Standard and Poor's reiterated its concerns regarding the effect of the unregulated business activities on the entire FPL Group "family" of companies, which includes FPL.

> The IPP financing strategy and the amount of risk mitigation undertaken will be important to sustaining current ratings for the entire FPL family . . . Resolution of the CreditWatch listing is expected in the near future. Notably, FPL Group's commitment to expand its nonregulated businesses, including its portfolio of IPPs, will challenge the firm to strengthen consolidated credit-protection measures to maintain the existing ratings profile.

The Credit Watch listing was resolved in September 2001, and the effects of FPL's nonutility spending were clear.

> Credit quality for Florida Power & Light Co., the utility operating company of FPL Group Inc., reflects the unit's steady and reliable cash flow attributes, tempered by the parent's growing portfolio of higher-risk, nonregulated investments, principally in independent power projects.
>
> Current ratings for FPL Group and its affiliates incorporate increasing business risk for the consolidated enterprise attributable to the growing nonregulated independent power producer (IPP)

> portfolio, regulatory challenges in Florida, an aggressive financing plan, and declining credit protection measures . . .
>
> Florida Power & Light's credit profile reflects an above-average business position . . . .
>
> Parent FPL Group's portfolio of nonregulated electric power generation holdings is in several regions, ... The potential for an economic downturn and the possibility of additional capacity coming on line in some of the regions that FPL Group has targeted highlight some of Standard & Poor's concerns . . . about this high-risk business line.

Similarly, Moody's also tied its concerns regarding the debt ratings for the FPL Group companies, including FPL, to the risk associated with FPL Group's unregulated business activities.

> [G]rowth strategies implemented by FPL Energy, an unregulated subsidiary of FPL Group, also increase pressure on the consolidated company's credit profile. FPL Energy intends to finance and build 6,000 mw of unregulated merchant generation by 2003. While most of these projects will eventually be financed with non-recourse debt, FPL Group Capital provides interim financing. The parent company guarantees the debt issued by FPL Capital which in turn creates pressure for all the rated entities within the consolidated group.

Q. What are the Standard and Poor's debt to total capitalization guidelines for an A rating on utility debt?

A. Standard and Poor's guidelines for an A rating and a company business risk profile of 4 (FPL's rankings) range from 46% to 50% debt to total capitalization.

Q. What is the average capitalization structure of the comparison group of A rated utilities utilized by Company witness Dr. Avera to develop his return on equity recommendation?

A. Dr. Avera computed the following average capitalization structure based upon his comparison group as of September 30, 2001.

CAPITALIZATION STRUCTURE DR. AVERA COMPARISON GROUP	
Short Term Debt	**2.1%**
Long Term Debt	**42.5%**
Preferred Securities	**5.4%**
Common Equity	**50.0%**
Total	**100.0%**

Dr. Avera noted that the individual common equity ratios embodied in the average ranged from a low of 42.9% to a high of 59.9%.

Q. **What is Mr. Avera's opinion of credit-rating agencies, such as those quoted above?**

A. "[P]erhaps the most objective guide to a utility's overall investment is its bond rating" assigned by "independent rating agencies." (Avera Direct, p. 47: 11-13).

Q. Is that similar to the opinion held by FPL's Mr. Dewhurst?

A. Yes. "Rating agencies, acting as independent risk assessors on behalf of investors generally, are an important source of evidence" of investors' sentiments. Dewhurst Direct Testimony, p. 19:18-22.

Q. What do the rating agencies think will be the outcome of this proceeding?

A. "[T]he market is expecting a rate cut" according to Justin McCann of Standard & Poor's (Miami Herald, February 24, 2002).

Q. Should ratepayers be required to subsidize FPL Group's nonregulated business activities through a capitalization structure that reflects a "bulked-up" common equity level so that FPL Group, on a consolidated basis, had adequate credit protection?

A. No. The unregulated business entities should provide the consolidated entity the necessary credit protections. It is inappropriate for the ratepayers to subsidize the FPL Group unregulated business activities through an excessive common equity level.

Q. Are there other factors that should be taken into account when assessing the appropriate level of equity capitalization for FPL?

A. Yes. Approximately 45% of FPL's total jurisdictional revenues are recovered by trackers, rather than through base rates.

Q. Is there another factor warranting consideration?

A. Yes. The timing, and perhaps to a lesser extent the scope, of FPL's present ambitious construction program are in part within FPL's control. FPL's determination to agree to a 20% (in lieu of a 15%) reserve margin, and its desire to build its own generation capacity, obviously influence its capital needs.

Q. What is your recommendation regarding the appropriate capitalization structure for FPL as a regulated utility?

A. I recommend the Commission adopt a capitalization structure of no more than 50% common equity and up to 50% debt, computed on a financial statement basis, excluding accumulated deferred income taxes and other Commission ratemaking adjustments. Once the determination is made regarding an appropriate financial statement capitalization structure, the Commission should adjust that structure for its various historic ratemaking adjustments, the largest of which is accumulated deferred income taxes.

Q. Have you quantified the return effects of the accumulated deferred income tax adjustments to capitalization and capitalization structure necessitated by your rate base adjustments?

A. Yes. The return effects of the prior rate base recommendations, excluding the effects of any further modifications to the capitalization structure quantified below, results in an increase to the revenue requirement of $34.140 million

Q. Have you quantified the effect of your recommendation on the capitalization structure for FPL?

A. Yes. This recommendation results in a reduction to the revenue requirement of $173.545 million. I have quantified this reduction to the revenue requirement as the difference between the Company's proposed grossed up overall rate of return and that corresponding to my recommendation (based upon the averages cited in Dr. Avera's testimony) times the rate base adjusted for the effects of the other adjustments that I have proposed. This adjustment is incremental to the previous adjustment for the return effects of the accumulated deferred income taxes.

VIII. SANFORD REPOWERING

Q. Please describe the Sanford Repowering Project (the "Sanford Project" or the "project").

A. The Sanford Project involved *inter alia* converting two previously oil- and gas-fired units, at the Sanford site, to gas fired combined cycle units.

Q. Did FPL originally project that the project would be in-service by 2002?

A. No. Originally FPL had scheduled the Sanford Project to be in-service after 2002.

Q. How did FPL evaluate the alternatives to repowering Sanford?

A. When we asked that question, FPL initially provided a generic description of criteria it claims it evaluated in determining whether to repower Sanford. Subsequently, FPL provided additional information.

Q. Did FPL compare the Sanford Repowering Project to a specific independent entity's project?

A. No.

Q. Did FPL's review of the Sanford Repowering Project use the cost which will be incurred to complete the project?

A. No.

Q. Did FPL conduct an RFP or open season to solicit bids in lieu of building its own capacity?

A. No.

Q. Mr. Waters discusses the Sanford Project in the context of the 1998 Ten Year Site Plan. What were the estimates of cost in 1998 for repowering Sanford Project?

A. FPL furnished a March 1998 "Summary of Alternatives" involving repowering Sanford in 2002 or 2004. The analysis, stated in 1998 dollars, estimated that repowering two units would cost $441 million (including $48 million for transmission expansion).

Moreover, the analysis showed that net per-KW costs would be reduced if re-powering was completed in 2004 rather than 2002. (Exh.___ (LK –10)).

Q. Was this estimate consistent with for the project's ultimate cost?

A. No. Neither were subsequent estimates. According to FPL, the project in October 1998 was forecast to cost $437 million; by August, 1999, that forecast had risen by over $100 million, to $546 million (Exh.___ (LK-11)). This reflected at least in part changing the identity of the two units to be repowered. Additionally, in October, 1998, the power delivery department estimated related costs of about $55 million (Exh.___ (LK-12)).

Q. Was $546 million the ultimate cost of the Sanford Project?

A. Far from it. The project budget authorized by FPL (excluding financing) reached $622 million by the summer of 2000 (Exh.___ (LK-13)).

Q. What is the most current forecast of the capital cost of the Project?

A. According to Mr. Waters, it is now approximately $697 million, or $75 million above the $622 million authorized project budget and almost $100 million above the August 1999 estimate. This includes at least $76 million for transmission interconnection work (*id.*).

Q. Has the Sanford Project been successful from the FPL perspective?

A. Evidently not. Even using FPL's "Sanford Repowering Success Criteria," which reflects the $622 million estimate, the project is $75 million over budget. (Exh.___ LK-14)).

Q. Can you identify major causes of the cost overrun?

CONFIDENTIAL INFORMATION FOLLOWS

[Confidential Information Intentionally Omitted]

[Confidential Information Intentionally Omitted]

END OF CONFIDENTIAL INFORMATION

Q. Has FPL changed when it anticipated incurring charges in connection with Sanford?

A. Yes. In a document dated May 9, 2001 (Exh.____ (LK-15)), FPL compared its "current approved 5-year forecasts" of expenditures for the Sanford (and Fort Myers) project(s) to its most up-to-date forecast. The comparison showed that the May 2001 forecast projects an increase in 2002 expenditures of $15 million, over what the then-current approved 5-year forecast had estimated, with reductions in expenditures shown in pre- and post-2002 periods.

Q. Prior to the construction report described above, and following changes in its original schedule, when did FPL project that the Sanford Project would be placed in-service?

A. In 2002.

Q. What is the impact of FPL's post-September 11, 2001 estimates of consumption upon the need for capacity?

A. FPL's "2002 Alt. Forecast," a post-September 11, 2001 projection, reflects a decrease of about 3% in the projected 2005 total consumption by jurisdictional customers compared to the pre-September 11, 2002 FPL 2002 Budget Forecast (Exh.____ LK-16)).

IX. AFFILIATE RELATIONSHIPS

Q. Do you have concerns with FPL's interrelations with its affiliates?

A. Yes. FPL is engaged in numerous transactions with its affiliates, including those involving millions of dollars but which are not subject to a written contract. *See* Exh.__ (LK-17). Unfortunately, FPL has resisted providing responsive information. Therefore, I reserve the opportunity to supplement this testimony when FPL has furnished adequate data.

Q. Does this complete your direct testimony?

A. For now.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

Re:	Review of the Retail Rates of Florida Power & Light Company	))	Docket No. 001148-EI

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

February 2002

WAS:92424.1

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

More than twenty-five years of utility industry experience in the financial, rate, tax, and planning areas. Specialization in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition diversification. Expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

1986 to Present:

J. Kennedy and Associates, Inc.: Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Minnesota, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, and West Virginia state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986:

Energy Management Associates: Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983:

The Toledo Edison Company: Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

RESUME OF LANE KOLLEN, VICE PRESIDENT

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for
Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Consumers
Kimberly-Clark
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial
Energy Consumers
Occidental Chemical Corporation
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy
Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

**Expert Testimony Appearances
of
Lane Kollen
As of January 2002**

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements. Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.

**Expert Testimony Appearances
of
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As of January 2002**

Date	Case	Jurisdict.	Party	Utility	Subject
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric	Financial workout plan. Corp.
5/88	M-87017 -1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017 -2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.

**Expert Testimony Appearances
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As of January 2002**

Date	Case	Jurisdict.	Party	Utility	Subject
7/88	M-87017--1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92
7/88	M-87017--2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No 92
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial Considerations, working capital
10/88	8800 355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87)
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71)
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No 87)
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No 87), Part 32, income tax normalization.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilites	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation

**Expert Testimony Appearances
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As of January 2002**

Date	Case	Jurisdict.	Party	Utility	Subject
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co	Recovery of CAAA costs, least cost financing
9/91	91-231 -E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy Corp	Merger
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.

**Expert Testimony Appearances
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As of January 2002**

Date	Case	Jurisdict.	Party	Utility	Subject
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	OPEB expense
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
3/93	93-01 EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp

Expert Testimony Appearances
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As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co	Incentive rate plan, earnings review
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co	Alternative regulation, cost allocation.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.

Expert Testimony Appearances
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As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co The Cleveland Electric Illuminating Co.	Competition, asset writeoffs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC No. 14967	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.

Expert Testimony Appearances
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As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. and Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.

Expert Testimony Appearances
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As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructunng, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.

Expert Testimony Appearances
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As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.

**Expert Testimony Appearances
of
Lane Kollen
As of January 2002**

Date	Case	Jurisdict.	Party	Utility	Subject
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers mechanisms	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery
4/99	99-02-05	CT	Connecticut Industrial Utility Customers mechanisms.	Connecticut Light and Power Co.	Regulatory assets and liabilities stranded costs, recovery
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers Kentucky Utilities Co.	Louisville Gas and Electric Co. and	Alternative regulation.

Expert Testimony Appearances
of
Lane Kollen
As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, and American Electric Power Co.	Merger Settlement Stipulation
7/99	97-596 (Surrebuttal)	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WVa	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 (Surrebuttal)	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 (Rebuttal)	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
8/99	98-474 98-083 (Rebuttal)	KY	Kentucky Industrial Utility Customers Kentucky Utilities Co.	Louisville Gas and Electric Co. and	Alternative forms of regulation.
8/99	98-0452-E-GI (Rebuttal)	WVa	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.

Expert Testimony Appearances
of
Lane Kollen
As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
10/99	U-24182 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	21527	TX	Dallas-Ft.Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
04/00	99-1212-EL-ETPOH 99-1213-EL-ATA 99-1214-EL-AAM		Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
01/00	U-24182 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
05/00	U-24182 (Supplemental Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
07/00	22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements In projected test year.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.

Expert Testimony Appearances
of
Lane Kollen
As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
11/00	PUC 22350 SOAH 473-00-1015	TX	The Dallas-Ft. Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 (Affidavit)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009		Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs
12/00	U-21453, U-20925, U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 (Direct)		Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925 and U-22092 (Subdocket B) (Surrebuttal)		Louisiana Public Service Commission Staff	Entergy Gulf States, Inc,.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy	Merger, savings, reliability.

Expert Testimony Appearances
of
Lane Kollen
As of January 2002

Date	Case	Jurisdict.	Party	Utility	Subject
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. and Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Public Service Comm Staff	Entergy Gulf States, Inc	Business separation plan: settlement agreement on overall plan structure
04 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc	Business separation plan: agreements, hold harmless conditions, separations methodology.
05 /01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution (Rebuttal)	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan agreements, hold harmless conditions, Separations methodology
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Public Service Comm Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Review requirements, Rate Plan, fuel clause recovery
11/01	14311-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.

Florida Power & Light Company
Docket No. 001148-EI
SFHA Fourth Set Interrogatories
Interrogatory No. 42
Page 1 of 1

Q.

Refer to MFR Schedule B-26 page 1 lines 15-27 regarding the adoption and changes in accounting for pension expense. Please provide a schedule detailing the history of the prepaid pension asset included in account 186.190, including any offsetting accumulated deferred income tax amounts by FERC account. For each year, commencing with 1993, cited as the year in which this change was implemented, through 2002, provide the beginning balance of the prepaid pension asset, increases or decreases for the year, and the ending balance. Reconcile the increases or decreases for each year to the Company's pension expense for that same year.

A.

See attached schedule.

South Florida Hospital Healthcare
Interrogatory #42
History of Acct. 186.190 - Prepaid Pension Asset
Years ending 1993 through 2002 (1)

[redacted]

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002 (1)
Beginning balance	19,542	(329)	11,637	25,069	43,354	112,110	173,331	262,799	371,180	473,902
Pension expense	14,592	11,966	18,726	18,285	68,757	9,626	89,469	108,381	101,895	109,798
Adjustments	(34,463) (2)		(5,294) (2)			(8,405) (2)				
Ending balance	(329)	11,637	25,069	43,354	112,110	113,331	262,799	371,180	473,075	583,700
Deferred Tax Balances Accounts 282 and 283	127	(4,489)	(9,670)	(16,724)	(43,247)	(46,862)	(101,375)	(143,182)	(182,468)	(225,142)

Notes:

(1) - Actual amounts for 1993 through 2001 and projected test year amounts for 2002.

(2) - These amounts relate to special retirement plans resulting from FPL's cost reduction programs.

Q.
Re: Testimony and Exhibits of Steven E. Harris

With respect to hurricanes at levels SS 1 through SS 5, please state the probability of each occurring during the year. Please also state the number of years between expected occurrences at each hurricane level.

A.
Refer to Document SPH-1 Section 11, Reference 1. The following table of likelihood of landfall is provided:

Table 2

ANNUAL PROBABILITY OF LANDFALLING STORMS

Region	SSI 1	SSI 2	SSI 3	SSI 4	SSI 5
Western (Manatee through Collier)	3.3%	2.0%	2.1%	0.4%	negligible
Southeastern (Dade/Broward/Palm Beach)	4.8%	5.3%	6.3%	2.4%	0.4%
Northeastern (Martin and north)	2.8%	2.8%	1.6%	0.5%	0.2%

The recurrence interval for the storm landfall probabilities provided in Table 2 above is:

Annual Probability	Recurrence Interval (years)
0.2%	500
0.4%	250
0.5%	200
1.6%	63
2.0%	50
2.1%	48
2.4%	42
2.8%	36
3.3%	30
4.8%	21
6.3%	16

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-4)
Response to SFHA Interrogatory No. 124

Florida Power & Light Company
Docket No. 001148-EI
SFHA Eighth Set of Interrogatories
Interrogatory No. 124
Page 1 of 1

Q.
<u>Re: Testimony and Exhibits of Steven E. Harris</u>

Separately for hurricane levels SS 1 through SS 5, please calculate exceedence probabilities in the form of Table 9-2.

A.
These analyses were not performed as part of the study.

Q.

Please provide a 6 year history of the storm damage fund reserve, consisting of actual amounts for 1997-2001 and projected amounts for the 2002 test year. Separately show for each year the beginning balance of the reserve, expense accruals, write-offs (charges), and ending balance of the reserve. Provide the requested amounts on a jurisdictional basis.

A.

Year	(1) Contributions/ Expense	(2) Fund arnings	(3) Storm Costs harged to Reserve	(7) Ending Reserve Balance	(8) Mark-to-Market djustment (FAS 115)	(9) Adjusted Ending Reserve Balance
Actual						
1996				221,244	1,333	222,577
1997	20,300	10,840	1,117	251,267	1,177	252,445
1998	20,300	12,459	27,554	256,472	2,116	258,588
1999	20,300	9,451	67,824	218,399	(2,820)	215,579
2000	20,300	9,075	17,566	230,208	(1,076)	229,132
2001	20,300	11,388	27,208	234,687	640	235,328
Projected						
000 (actual)				230,208	(1,076)	229,132
2001 (a)	20,300	9,596	(b)	260,104	1,399	261,504
2002	50,300	10,221	(b)	320,625	1,399	322,025

(a) five months actual, seven months projected

(b) the number and costs of storms are too unpredictable to predict.

See MFR C-9 (account 924) for the jurisdictional factor applicable to the annual expense accrual. See MFR B-7 for the jurisdictional factor applicable to the reserve balance. Note- the storm and property damage reserve is a funded reserve which is excluded from rate base (see MFR B-4).

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-6)
Operating Expenses - Budgeted and Actual

Florida Power & Light Company
Docket No. 001148-EI
SFHA Fifth Set of Interrogatories
Interrogatory No. 57
Page 1 of 1

Q.
Please compare your operating budget by year established in advance for fiscal years 1998, 1999, 2000 and 2001 with the actual results of operations experienced during such respective periods.

A.

($ in millions)

	1998		1999		2000		2001	
Expenses:	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan
Fuel and Purchased Power	$ 2,175	$ 2,244	$ 2,232	$ 2,191	$ 2,511	$ 2,253	$ [redacted]	$ [redacted]
Base O&M	1,088	1,090	1,026	1,072	999	1,034	[redacted]	[redacted]
Depreciation and Amortization	1,249	1,078	989	1,263	975	924	[redacted]	[redacted]
Taxes	952	945	959	928	975	968	[redacted]	[redacted]
Other, primarily interest	286	293	233	246	256	255	[redacted]	[redacted]
	$ 5,750	$ 5,650	$ 5,439	$ 5,700	$ 5,716	$ 5,434	$ [redacted]	$ [redacted]

(Actuals - Babka)
(Plan - Beilhart)

The information requested for 2001 is confidential and will be made available for inspection at FPL's General Offices at 9250 West Flager Street, Miami, Florida 33174 during normal business hours pursuant to a mutually satisfactory confidentiality agreement or protective order.

Q.

Re: Testimony and Exhibits of John G. Shearman

Please discuss and describe in detail and provide all documents related to, Mr. Shearman's investigation concerning whether, or the extent to which, FPL's efforts to reduce costs during the period 1999 - 2001, will cause or could cause costs in any category to increase for any period following 2001. If Mr. Shearman did not investigate that topic please so state.

A.

Mr. Shearman did not specifically investigate, or testify on this exact topic. However, FPL's track record of consistent year-on-year cost reductions began well in advance of the 1999-2001 time period referenced and therefore implies no history of such decision-making. Please see pages 22 through 23 of Mr. Shearman's testimony for a complete description of his opinions on FPL's future O&M expenses.

Q.

Re: Testimony and Exhibits of John G. Shearman

Please quantify in Mr. Shearman's opinion the amount of increase in net profits that FPL enjoyed during the period 1999- April 1, 2002 as a result of FPL's lower costs and efficiency enhancements. Please provide your workpapers and supporting documents and describe how you went about calculating the amount.

A.

FPL objects to this interrogatory as it seeks analyses that have not been performed. or data that have not been collected with the preparation of the FPL witnesses' testimony.

Q.

Re: Testimony and Exhibits of John G. Shearman

With respect to Mr. Shearman's testimony and exhibits please compare the weighted average age of the FPL generation fleet with that of the various samples that are used for comparison purposes in Mr. Shearman's materials.

A.

FPL objects to this interrogatory as it seeks analyses that have not been performed. or data that have not been collected with the preparation of the FPL witnesses' testimony.

Q.

<u>Re: Testimony and Exhibits of John G. Shearman</u>

With respect to Document JMS-3, please indicate the size of the sample (a) within the United States and (b) outside the United States. Please indicate the type(s) of reactor operated by FPL, and the proportion of reactors of that type in the sample population, broken out as between those in the United States and those outside of the United States. Please identify the other type(s) of reactors that are contained in the sample population and the relative percentages that each represents of the sample population. Please provide a comparable set of data for Documents JMS-4 and JMS-5. In the witness' opinion, what is the cause of the significant decrease in forced outage rates for the sample group from 1997 through 2000.

A.

FPL objects to this interrogatory as it seeks analyses that have not been performed, or data that have not been collected, in connection with the preparation of the FPL witnesses' testimony.

	Alternatives:	RePower PFM Unit 1&2	3 Escalation Notes
	I. CONSTRUCTION (1000) 1997 $		
A	Permit/Eng/Fab (months)	24	
B	Construction Phase (months)	30	
C	Project Total (months)	54	
D	Land	($1,681)	1
E	Materials	$281,802	2
F	Labor & Equipment	$75,450	
G	Total Direct Cost	$345,571	
H	Construction Indirects	$0	
I	Licensing	$5,000	
J	Project Support	$5,000	
K	Contingency	$20,000	
L	Total Indirect Cost	$30,000	
M	$/KW Net Summer	$275	
N	$/KW Net Winter	$256	
O	Fuel Expansion	$6,000	
P	Transmission Expansion	$23,000	
Q	Railroad & Cars	$0	
R	Total Other Cost	$29,000	
S	Grand Total Cost	$414,571	
T	$/KW Net Summer	$296	
U	$/KW Net Winter	$275	
	II. PLANT CHARACTERISTICS		
V	Net Sum 95FCapability (mw)	1,400	
W	Net 75F Capability (mw)	1,508	
	Net 59F Capability (mw)	1,541	
X	Heat Rate btu/kwh 95F100% Load HHV	6,959	
Y	Heat Rate btu/kwh 75F100% Load HHV	6,815	
Y1	Heat Rate btu/kwh 75F 75% Load HHV	6,990	
Y2	Heat Rate btu/kwh 75F 50% Load HHV	7,630	
Z	Heat Rate btu/kwh 59F100% Load HHV	6,763	
AA	Equiv. Avail. %	90%	
BB	Sched Outage (wks/yr)	1.5	
CC	Equiv Forced Outage	1.0%	
	III. OPERATION		
DD	Total O&M (mm/yr)	$3	
EE	(remove 6MM for existing fleet cost		
FF	for Repower only)		
GG	Capital Replace ($mm/yr)	$6	
	IV. SPENDING CURVES		
HH	Year 6	$0	
II	Year 5	$0	
JJ	Year 4	$1,658	
KK	Year 3	$2,902	
LL	Year 2	$193,190	
MM	Year 1	$216,821	
	V. NOTES:		
NN		New NRC	
	Fuel	Natural Gas	
	AFUDC Adder		
OO	Equipment	"7F ++" 6CT & 6HRSG	
PP	Cooling	Intake/Discharge	
QQ	SCR's	no	
RR			

1 $4MM Sale Price minus$519k Site Demo and $1.6MM Book Value(1996 $$)

2 $150MM to be issued in 1997 PO's

3 All other numbers have not been escalated

IRP_Repower PFM 11296ESC

SUMMARY OF GENERATION ALTERNATIVES
COST AND COMPETITION TEAM
IRP 1998

	New Generation Alternatives				
		16	17	18	19
	Alternatives:	400 PC	400 PC	200 SC	500 CC - F++
		Greenfield	Martin	Exist Site - "G"	Greenfield
	I. CONSTRUCTION (1000) 1998 $				
A	Permit/Eng/Fab (months)	36	30	9	24
B	Construction Phase (months)	30	27	6	24
C	Project Total (months)	66	57	15	48
D	Land	$ 1,210	$ -	$ -	$ 1,200
E	Materials	$ 226,000	$ 224,000	$ 42,069	$ 120,000
F	Labor & Equipment	$ 104,000	$ 104,000	$ 6,333	$ 44,000
G	Total Direct Cost	$ 331,210	$ 328,000	$ 48,402	$ 165,200
H	Construction Indirects	$ -	$ -	$ -	$ -
I	Licensing	$ 6,000	$ 5,500	$ 400	$ 3,200
J	Project Support	$ 4,220	$ 3,616	$ 1,090	$ 2,700
K	Contingency	$ 10,657	$ 8,799	$ 249	$ 6,844
L	Total Indirect Cost	$ 20,877	$ 17,915	$ 1,739	$ 12,744
M	$/KW Net Summer	$ 880	$ 865	$ 251	$ 374
N	$/KW Net Winter	$ 873	$ 860	$ 218	$ 346
O	Fuel Expansion	$ -	$ -	$ 200	$ 4,000
P	Transmission Expansion				$ 13,000
Q	Railroad & Cars	$ 8,000	$ 8,000	$ -	$ -
R	Total Other Cost	$ 8,000	$ 8,000	$ 200	$ 17,000
S	Grand Total Cost	$ 360,087	$ 353,915	$ 50,341	$ 194,944
T	$/KW Net Summer	$ 900	$ 885	$ 252	$ 410
U	$/KW Net Winter	$ 896	$ 880	$ 219	$ 379
	II. PLANT CHARACTERISTICS				
V	Net Sum 95F Capability (mw)	400	400	200	476
v	Net Win 75F Capability (mw)	401	401	215	496
W	Net Win 59F Capability (mw)	402	402	230	514
X	Heat Rate btu/kwh 75F 100% Load HHV	9,500	9,500	9,955	6,876
Y	Heat Rate btu/kwh 75F 75%	9,600	9,600	10,801	6,816
Z	Heat Rate btu/kwh 75F 50%	10,100	10,100	12,344	6,773
AA	Equiv. Avail. %	97%	97%	98%	96%
BB	Sched Outage (wks/yr)	1.0	1.0	0.5	1.5
CC	Equiv Forced Outage	1.0%	1.0%	1.0%	1.0%
	III. OPERATION				
DD	Total O&M (mm/yr)	[illegible]	[illegible]	0.51	3.57
EE	Fixed ($/kw - yr)	18.66	13.96	0.51	4.31
FF	Variable (excl. fuel) ($/mwh)	1.603	1.603	0.295	0.405
GG	Capital Replace ($mm/yr)	3.00	3.00	1.50	2.30
	IV. SPENDING CURVES				
HH	Year 6	$ 1,440	$ -	$ -	$ -
II	Year 5	$ 7,202	$ 6,724	$ -	$ -
JJ	Year 4	$ 8,642	$ 8,494	$ -	$ 780
KK	Year 3	$ 61,935	$ 62,643	$ -	$ 1,365
LL	Year 2	$ 97,944	$ 96,265	$ 17,620	$ 90,844
MM	Year 1	$ 182,924	$ 179,789	$ 32,722	$ 101,956
	V. NOTES:	$ 360,087	$ 353,915	$ 50,341	$ 194,944
NN	*Net MW change (summer)*	+400	+400	+200	+476
		New NSC	New NSC	New NSC	New NSC
	Equipment Available				
OO	Equipment	PC	PC	1-CT - "G"	7F++* 2CT&2HRSG&1ST
PP	Cooling	Tower	Reservoir	Existing	Tower
QQ	SCR's	yes - SCR	yes - SCR	no	no
RR	Back-Up Fuel Adder	$ [illegible]	$ 3,000	$ 2,500	$ 3,500

60005014

SUMMARY OF GENERATION ALTERNATIVES
COST AND COMPETITION TEAM
IRP 1998

	New Generation Alternatives							
		9	10	11	12	13	14	15
	Alternatives:	Repower PSN 3	Repower PFM-1	Repower PCU-5	400 Orl Martin	800 Orl Martin	400 CFB Greenfield	400 CFB Martin
	I. CONSTRUCTION (1000) 1998 $							
A	Permit/Eng/Fab (months)	24	30	30	30	30	33	30
B	Construction Phase (months)	21	24	21	30	30	30	27
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
D	Land	$ -	$ -	$ -	$ -	$ -	$ 1,210	$ -
E	Materials	$ 95,151	$ 100,735	$ 45,934	$ 202,000	$ 400,000	$ 224,210	$ 224,210
F	Labor & Equipment	$ 18,132	$ 29,853	$ 18,193	$ 106,000	$ 180,000	$ 95,586	$ 95,586
G	Total Direct Cost	$ 113,283	$ 130,588	$ 64,127	$ 308,000	$ 580,000	$ 321,006	$ 319,796
H	Construction Indirects	$ 2,973	$ 3,265	$ 1,603	$ -	$ -	$ -	$ -
I	Licensing	$ 3,000	$ 3,000	$ 4,000	$ 8,500	$ 8,500	$ 6,000	$ 5,500
J	Project Support	$ 5,830	$ 4,000	$ 4,000	$ 3,548	$ 3,836	$ 4,100	$ 3,608
K	Contingency	$ 13,759	$ 8,451	$ 4,424	$ 9,482	$ 20,693	$ 10,244	$ 8,512
L	Total Indirect Cost	$ 25,562	$ 18,716	$ 14,027	$ 21,530	$ 33,029	$ 20,344	$ 17,620
M	$/KW Net Summer	$ 503	$ 541	$ 662	$ 824	$ 766	$ 853	$ 844
N	$/KW Net Winter	$ 422	$ 454	$ 579	$ 820	$ 762	$ 849	$ 839
O	Fuel Expansion	$ -	$ 95,000	$ -	$ 16,000	$ 16,000	$ -	$ -
P	Transmission Expansion							
Q	Railroad & Cars	$ -	$ -	$ -	$ -	$ -	$ 8,000	$ 8,000
R	Total Other Cost	$ -	$ 95,000	$	$ 16,000	$ 16,000	$ 8,000	$ 8,000
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
U	$/KW Net Winter	$ 422	$ 743	$ 579	$ 860	$ 782	$ 869	$ 859
	II. PLANT CHARACTERISTICS							
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
V	Net Win 75F Capability (mw)	316	316	130	401	802	401	401
W	Net Win 59F Capability (mw)	329	329	135	402	804	402	402
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Y	Heat Rate btu/kwh 75F 75%	7,619	7,619	7,820	10,004	10,004	9,700	9,700
Z	Heat Rate btu/kwh 75F 50%	7,429	7,429	8,580	10,384	10,384	10,200	10,200
AA	Equiv. Avail. %	96%	95%	95%	97%	97%	97%	97%
BB	Sched Outage (wks/yr)	1.3	1.6	1.6	1.0	1.0	1.0	1.0
CC	Equiv Forced Outage	1.5%	2.0%	2.0%	1.0%	1.0%	1.0%	1.0%
	III. OPERATION							
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
EE	Fixed ($/kw - yr)	5.37	5.58	9.92	10.62	6.89	15.40	10.70
FF	Variable (excl. fuel) ($/mwh)	0.585	0.620	1.064	1.671	1.585	1.497	1.497
GG	Capital Replace ($mm/yr)	2.10	2.10	1.00	2.00	3.00	2.00	2 00
	IV. SPENDING CURVES							
HH	Year 6	$ -	$ -	$ -	$ -	$ -	$ 1,397	$ -
II	Year 5	$ -	$ -	$ -	$ 5,874	$ 10,694	$ 6,987	$ 5,872
JJ	Year 4	$ 2,638	$ 4,642	$ 1,485	$ 8,293	$ 15,097	$ 8,384	$ 8,290
KK	Year 3	$ 17,356	$ 30,538	$ 9,769	$ 61,850	$ 112,596	$ 60,088	$ 61,829
LL	Year 2	$ 59,148	$ 104,073	$ 33,294	$ 93,984	$ 171,096	$ 95,023	$ 93,953
MM	Year 1	$ 59,704	$ 105,051	$ 33,606	$ 175,529	$ 319,547	$ 177,470	$ 175,471
	V. NOTES:	$ 138,845	$ 244,304	$ 78,154	$ 345,530	$ 629,028	$ 349,350	$ 345,416
NN	Net MW change (summer)	+276 From NSC Incremental	+276 From NSC Incremental	+118 From NSC Incremental	+400 New NSC	+800 New NSC	+400 New NSC	+400 New NSC
OO	Equipment Available Equipment	"F" 2CT&2HRSG	"F" 2CT&2HRSG	V84.3 1CT &1HRSG	N/A	N/A	1CFB	1CFB
PP	Cooling	Existing	Existing	Existing	Reservoir	Reservoir	Tower	Reservoir
QQ	SCR's	no	no	no	no	no	yes - SNCR	yes - SNCR
RR	[illegible] Adder	$ 2,500	$ [illegible]	$ 1,500	$ 3,000	$ 3,000	$ [illegible]	[illegible]

60005015

SUMMARY OF GENERATION ALTERNATIVES
COST AND COMPETITION TEAM
IRP 1998

	New Generation Alternatives						
		1	1A	2	3	3A	4
	Alternatives:	400 CC - ATS Greenfield	400 CC - ATS Greenfield	300 CC - G Greenfield	400 CC - ATS Martin	400 CC - ATS Martin	300 CC - G Martin
	I. CONSTRUCTION (1000) 1998 $						
A	Permit/Eng/Fab (months)	30	30	30	20	20	20
B	Construction Phase (months)	22	22	22	19	19	19
C	Project Total (months)	52	52	52	39	39	39
D	Land	$ 1,298	$ 1,298	$ 1,298	$ -	$ -	$ -
E	Materials	$ 125,000	$ 125,000	$ 88,747	$ 123,000	$ 123,000	$ 88,747
F	Labor & Equipment	$ 35,000	$ 35,000	$ 25,253	$ 35,000	$ 35,000	$ 25,253
G	Total Direct Cost	$ 161,298	$ 161,298	$ 115,298	$ 158,000	$ 158,000	$ 114,000
H	Construction Indirects	$ -	$ -	$ -	$ -	$ -	$ -
I	Licensing	$ 4,000	$ 4,000	$ 4,000	$ 3,200	$ 3,200	$ 3,200
J	Project Support	$ 3,476	$ 3,476	$ 3,476	$ 2,700	$ 2,700	$ 2,700
K	Contingency	$ 8,439	$ 8,439	$ 6,139	$ 6,556	$ 6,556	$ 4,560
L	Total Indirect Cost	$ 15,915	$ 15,915	$ 13,615	$ 12,456	$ 12,456	$ 10,460
M	$/KW Net Summer	$ 423	$ 423	$ 416	$ 407	$ 407	$ 402
N	$/KW Net Winter	$ 396	$ 396	$ 373	$ 380	$ 380	$ 360
O	Fuel Expansion				$ 12,000	$ 12,000	$ 10,000
P	Transmission Expansion						
Q	Railroad & Cars	$ -	$ -	$ -	$ -	$ -	$ -
R	Total Other Cost	$ -	$ -	$ -	$ 12,000	$ 12,000	$ 10,000
S	Grand Total Cost	$ 177,213	$ 177,213	$ 128,913	$ 182,456	$ 182,456	$ [illegible]
T	$/KW Net Summer	$ 423	$ 423	$ 416	$ 435	$ 435	$ [illegible]
U	$/KW Net Winter	$ 396	$ 396	$ 373	$ 407	$ 407	$ 389
	II. PLANT CHARACTERISTICS						
V	Net Sum 95F Capability (mw)	419	419	310	419	419	310
v	Net Win 75F Capability (mw)	430	430	332	430	430	332
W	Net Win 59F Capability (mw)	448	448	346	448	448	346
X	Heat Rate btu/kwh 75F 100% Load HHV	6,300	6,081	6,500	6,300	6,081	6,500
Y	Heat Rate btu/kwh 75F 75%	6,470	6,245	6,768	6,470	6,245	6,768
Z	Heat Rate btu/kwh 75F 50%	6,970	6,729	7,389	6,970	6,729	7,389
AA	Equiv. Avail. %	96%	96%	96%	96%	96%	96%
BB	Sched Outage (wks/yr)	1.5	1.5	1.5	1.5	1.5	1.5
CC	Equiv Forced Outage	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
	III. OPERATION						
DD	Total O&M (mm/yr)	4.55	4.55	[illegible]	3.23	3.23	[illegible]
EE	Fixed ($/kw - yr)	7.69	7.69	7.69	4.31	4.31	4.31
FF	Variable (excl. fuel) ($/mwh)	0.405	0.405	0.602	0.405	0.405	0.602
GG	Capital Replace ($mm/yr)	2.30	2.30	2.30	2.30	2.30	2.30
	IV. SPENDING CURVES						
HH	Year 6	$ -	$ -	$ -	$ -	$ -	$ -
II	Year 5	$ 709	$ 709	$ 516	$ -	$ -	$ -
JJ	Year 4	$ 1,418	$ 1,418	$ 1,031	$ 730	$ 730	$ 538
KK	Year 3	$ 30,126	$ 30,126	$ 21,915	$ 1,277	$ 1,277	$ 941
LL	Year 2	$ 56,708	$ 56,708	$ 41,252	$ 85,024	$ 85,024	$ 62,658
MM	Year 1	$ 88,252	$ 88,252	$ 64,199	$ 95,424	$ 95,424	$ 70,323
	V. NOTES:	$ 177,213	$ 177,213	$ 128,913	$ 182,456	$ 182,456	$ 134,460
NN	Net MW change (summer)	+419 New NSC	+419 New NSC	+310 New NSC	+419 New NSC	+419 New NSC	+310 New NSC
	Equipment Available	2003-2005	2006+	2000+	2003-2005	2006+	2000+
OO	Equipment	ATS - "H" 1CT & 1HRSG	ATS - "H" 1CT & 1HRSG	"G" 1CT & 1HRSG	ATS - "H" 1CT & 1HRSG	ATS - "H" 1CT & 1HRSG	"G" 1CT & 1HRSG
PP	Cooling	Tower	Tower	Tower	Reservoir	Reservoir	Reservoir
QQ	SCR's	no	no	no	no	no	no
RR	Dual Fuel Adder	$ 3,500	$ [illegible]	$ 3,500	$ 3,500	$ 3,500	[illegible]

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-10)
Sanford Comparisons

SUMMARY OF GENERATION ALTERNATIVES
COST AND COMPETITION TEAM
IRP 1998

	New Generation Alternatives	5	5A	6	6A	7	8
	Alternatives:	800 CC - ATS Greenfield	800 CC - ATS Greenfield	800 CC - ATS Martin	800 CC - ATS Martin	Repower Hot/Wind Box PTF-1	Repower PRV 2
	I. CONSTRUCTION (1000) 1998 $						
A	Permit/Eng/Fab (months)	30	30	20	20	24	24
B	Construction Phase (months)	27	27	22	22	22	17
[redacted]							
D	Land	$ 2,596	$ 2,596	$ -	$ -	$ -	$ -
E	Materials	$ 241,250	$ 241,250	$ 237,250	$ 237,250	$ 58,735	$ 52,923
F	Labor & Equipment	$ 67,550	$ 67,550	$ 67,550	$ 67,550	$ 17,696	$ 10,110
G	Total Direct Cost	$ 311,396	$ 311,396	$ 304,800	$ 304,800	$ 76,431	$ 63,033
H	Construction Indirects	$ -	$ -	$ -	$ -	$ 1,911	$ 2,043
I	Licensing	$ 4,000	$ 4,000	$ 3,200	$ 3,200	$ 3,000	$ 3,000
J	Project Support	$ 4,418	$ 4,418	$ 3,646	$ 3,646	$ 4,000	$ 5,788
K	Contingency	$ 15,991	$ 15,991	$ 14,024	$ 14,024	$ 6,827	$ 8,125
L	Total Indirect Cost	$ 24,409	$ 24,409	$ 20,870	$ 20,870	$ 15,738	$ 18,956
M	$/KW Net Summer	$ 401	$ 401	$ 369	$ 369	$ 683	$ 410
N	$/KW Net Winter	$ 375	$ 375	$ 363	$ 363	$ 580	$ 363
O	Fuel Expansion			$ 16,000	$ 16,000	$ -	$ -
P	Transmission Expansion						
Q	Railroad & Cars	$ -	$ -	$ -	$ -		$ -
R	Total Other Cost	$ -	$ -	$ 16,000	$ 16,000	$ -	$ -
[redacted]							
U	$/KW Net Winter	$ 375	$ 375	$ 381	$ 381	$ 580	$ 363
	II. PLANT CHARACTERISTICS						
[redacted]							
v	Net Win 75F Capability (mw)	860	860	860	860	153	217
W	Net Win 59F Capability (mw)	896	896	895	896	159	226
[redacted]							
Y	Heat Rate btu/kwh 75F 75%	6,470	6,245	6,470	6,245	8,272	7,911
Z	Heat Rate btu/kwh 75F 50%	6,970	6,729	6,970	6,729	8,417	8,512
AA	Equiv. Avail. %	96%	96%	96%	96%	95%	96%
BB	Sched Outage (wks/yr)	1.5	1.5	1.5	1.5	1.6	1.3
CC	Equiv Forced Outage	1.0%	1.0%	1.0%	1.0%	2.0%	1.5%
	III. OPERATION						
[redacted]							
EE	Fixed ($/kw - yr)	5.15	5.15	3.82	3.82	9.58	6.82
FF	Variable (excl. fuel) ($/mwh)	0.382	0.382	0.382	0.382	0.623	0.819
GG	Capital Replace ($mm/yr)	4.60	4.60	4.60	4.60	1.00	1.00
	IV. SPENDING CURVES						
HH	Year 6	$ -	$ -	$ -	$ -	$ -	$ -
II	Year 5	$ 1,679	$ 1,679	$ -	$ -	$ 1,567	$ -
JJ	Year 4	$ 18,805	$ 18,805	$ 2,733	$ 2,733	$ 2,212	$ 1,558
KK	Year 3	$ 43,990	$ 43,990	$ 4,783	$ 4,783	$ 16,498	$ 10,249
LL	Year 2	$ 119,882	$ 119,882	$ 157,510	$ 157,510	$ 25,070	$ 34,927
MM	Year 1	$ 151,448	$ 151,448	$ 176,643	$ 176,643	$ 46,822	$ 35,255
	V. NOTES:	$ 335,805	$ 335,805	$ 341,670	$ 341,670	$ 92,169	$ 81,989
NN	Net MW change (summer)	+838 New NSC	+838 New NSC	+838 New NSC	+838 New NSC	+135 From NSC Incremental	+200 New NSC
	Equipment Available	2003-2005	2006+	2003-2005	2006+		
OO	Equipment	ATS - "H" 2CT & 2HRSG	ATS - "H" 2CT & 2HRSG	ATS - "H" 2CT & 2HRSG	ATS - "H" 2CT & 2HRSG	V84.3 1CT	"F" 1CT &1HRSG
PP	Cooling	Tower	Tower	Reservoir	Reservoir	Existing	Existing
QQ	SCR's	no	no	no	no	no	no
RR	IRP98BOX.XLS Gas/Oil Adder	$ 7,000	$ Page 80	$ 7,000	$ 7,000	$ 1,... 6/05/98	4:24 PM

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SUMMARY OF GENERATION ALTERNATIVES
NEW PLANT ENTRY PRICE

	Alternatives:	500 MW Combined Cycle	RePower PFM Unit 1&2
	I. CONSTRUCTION (1000) 1997 $		
A	Permit/Eng/Fab (months)	24	24
B	Construction Phase (months)	24	30
C	Project Total (months)	48	54
D	Land	$1,200	($1,681)
E	Materials	$120,000	$276,802
F	Labor & Equipment	$44,000	$75,450
G	Total Direct Cost	$165,200	$350,571
H	Construction Indirects	$0	$0
I	Licensing	$3,200	$5,000
J	Project Support	$2,700	$5,000
K	Contingency	$6,844	$20,000
L	Total Indirect Cost	$12,744	$30,000
M	$/KW Net Summer	$374	$269
N	$/KW Net Winter	$359	$258
O	Fuel Expansion	$4,000	$6,000
P	Transmission Expansion	$13,000	$23,000
Q	Railroad & Cars	$0	$0
R	Total Other Cost	$17,000	$29,000
S	Grand Total Cost	$194,944	$409,571
T	$/KW Net Summer	$410	$290
U	$/KW Net Winter	$393	$278
	II. PLANT CHARACTERISTICS		
V	Net Sum 95FCapability (mw)	476	1,413
W	Net 75F Capability (mw)	496	1,473
	Net 59F Capability (mw)	514	1,525
X	Heat Rate btu/kwh 95F100% Load HHV	6,870	6,940
Y	Heat Rate btu/kwh 75F100% Load HHV	6,816	6,885
Z	Heat Rate btu/kwh 59F100% Load HHV	6,773	6,840
AA	Equiv. Avail. %	96%	96%
BB	Sched Outage (wks/yr)	1.5	1.5
CC	Equiv Forced Outage	1.0%	1.0%
	III. OPERATION		
DD	Total O&M (mm/yr)	$3.67	$8
EE	(remove 6MM for existing fleet cost		
FF	for Repower only)		
GG	Capital Replace ($mm/yr)	2.30	$6
	IV. SPENDING CURVES		
HH	Year 6	$0	$0
II	Year 5	$0	$0
JJ	Year 4	$780	$1,638
KK	Year 3	$1,365	$2,867
LL	Year 2	$90,844	$190,860
MM	Year 1	$101,956	$214,206
	V. NOTES:		
NN			
	Fuel	New NSC Natural Gas	New NSC Natural Gas
	AFUDC Adder		
OO	Equipment	"7F ++" 2CT & 2HRSG&1ST	"7F ++" 6CT & 6HRSG
PP	Cooling	Mech Draft	Intake/Discharge
QQ	SCR's	no	no
RR			

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New Generation Alternatives

	Alternatives:	Repower HotWind Box PTF-1	Repower PRV 2	Repower PSN 3	Repower PFM-1	Repower PCU-5	400 On Martin	13 800 On Martin
	I. CONSTRUCTION (1000) 1996 $							
A	Permit/Eng/Fab (months)	24	24	24	30	30	30	30
B	Construction Phase (months)	22	17	21	24	21	30	30
C	Project Total (months)	46	41	45	54	51	60	60
D	Land	$ -	$ -	$ -	$ -	$ -	$ -	$
E	Materials	$ 58,735	$ 52,923	$ 95,151	$ 100,735	$ 45,934	$ 202,000	$ 400,000
F	Labor & Equipment	$ 17,696	$ 10,110	$ 18,132	$ 29,853	$ 18,193	$ 106,000	$ 180,000
G	Total Direct Cost	$ 76,431	$ 63,033	$ 113,283	$ 130,588	$ 64,127	$ 308,000	$ 580,000
H	Construction Indirects	$ 1,911	$ 2,043	$ 2,973	$ 3,265	$ 1,603	$ -	$ -
I	Licensing	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 4,000	$ 8,500	$ 8,500
J	Project Support	$ 4,000	$ 5,788	$ 5,830	$ 4,000	$ 4,000	$ 3,548	$ 3,836
K	Contingency	$ 6,827	$ 8,125	$ 13,759	$ 8,451	$ 4,424	$ 9,482	$ 20,693
L	Total Indirect Cost	$ 15,738	$ 18,956	$ 25,562	$ 18,716	$ 14,027	$ 21,530	$ 33,029
M	$/KW Net Summer	$ 683	$ 410	$ 503	$ 541	$ 662	$ 824	$ 766
N	$/KW Net Winter	$ 580	$ 363	$ 422	$ 454	$ 579	$ 820	$ 762
O	Fuel Expansion	$ -	$ -	$ -	$ 95,000	$ -	$ 16,000	$ 16,000
P	Transmission Expansion							
Q	Railroad & Cars		$ -	$ -	$ -	$ -	$ -	$ -
R	Total Other Cost	$ -	$ -	$ -	$ 95,000	$ -	$ 16,000	$ 16,000
S	Grand Total Cost	$ 92,169	$ 81,989	$ 138,645	$ 244,304	$ 78,154	$ 345,530	$ 629,029
T	$/KW Net Summer	$ 683	$ 410	$ 503	$ 885	$ 662	$ 864	$ 786
U	$/KW Net Winter	$ 580	$ 363	$ 422	$ 743	$ 579	$ 860	$ 782
	II. PLANT CHARACTERISTICS							
V	Net Sum 95F Capability (mw)	135	200	276	276	118	400	800
W	Net Win 59F Capability (mw)	159	226	329	329	135	402	804
X	Heat Rate btu/kwh 75F 100% Load HHV	8,368	7,615	7,379	7,379	7,570	9,683	9,683
Y	Heat Rate btu/kwh 75F 75%	8,272	7,911	7,619	7,619	7,820	10,004	10,004
Z	Heat Rate btu/kwh 75F 50%	8 417	8,512	7,429	7,429	8,580	10,384	10,384
AA	Equiv. Avail. %	95%	96%	96%	95%	95%	97%	97%
BB	Sched Outage (wks/yr)	1.6	1.3	1.3	1.6	1.6	1.0	1.0
CC	Equiv Forced Outage	2.0%	1.5%	1.5%	2.0%	2.0%	1.0%	1.0%
	III. OPERATION							
DD	Total O&M (mm/yr)	1.99	2.74	2.84	2.97	2.22	9.93	16.29
EE	Fixed ($/kw - yr)	9.58	6.82	5.37	5.58	9.92	10.62	6.89
FF	Variable (excl. fuel) ($/mwh)	0.623	0.819	0 585	0.620	1.064	1.671	1.585
GG	Capital Replace ($mm/yr)	1.00	1.00	2 10	2.10	1.00	2.00	3.00
	IV. SPENDING CURVES							
HH	Year 6	-	-	-	-	-	-	$ -
II	Year 5	$ 1,567	$ -	$ -	$ -	$ -	$ 5,874	$ 10,694
JJ	Year 4	$ 2,212	$ 1,558	$ 2,638	$ 4,642	$ 1,485	$ 8,293	$ 15,097
KK	Year 3	$ 16,498	$ 10,249	$ 17,356	$ 30,538	$ 9,769	$ 61,850	$ 112,596
LL	Year 2	$ 25,070	$ 34,927	$ 59,148	$ 104,073	$ 33,294	$ 93,984	$ 171,096
MM	Year 1	$ 46,822	$ 35,255	$ 59,704	$ 105,051	$ 33,606	$ 175,529	$ 319,547
	V. NOTES:	$ 92,169	$ 81,989	$ 138,845	$ 244,304	$ 78,154	$ 345,530	$ 629,029
NN	Net MW change (summer)	+135 From NSC Incremental	+200 New NSC	+276 From NSC Incremental	+276 From NSC Incremental	+118 From NSC Incremental	+400 New NSC	+800 New NSC
OO	Equipment	V84.3 1CT	"F" 1CT &1HRSC	"F" 2CT&2HRSG	"F" 2CT&2HRSG	V84.3 1CT & 1HRSG	N/A	N/A
PP	Cooling	Existing	Existing	Existing	Existing	Existing	Reservoir	Reservoir
QQ	SCR's	no	no	no	no	no	no	no
RR	Back-Up Fuel Adder	$ 1,500	$ 2,500	$ 2,500	$ 3,000	$ 1,500	$ 3,000	$ 3,000

60005019

Repower Sanford
2002 and 2004

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-10
Sanford Comparisons
Page 8 of 17

		2002	2004
	Alternatives:	RePower PSN Units 3&4	RePower PSN Units 3&4
	I. CONSTRUCTION (1000) 1998 $		
A	Permit/Eng/Fab (months)	24	24
B	Construction Phase (months)	24	24
C	Project Total (months)	48	48
D	Land	$0	$0
E	Materials	$279,521	$279,521
F	Labor & Equipment	$77,075	$77,075
G	Total Direct Cost	$356,596	$356,596
H	Construction Indirects	$0	$0
I	Licensing	$5,000	$5,000
J	Project Support	$5,000	$5,000
K	Contingency	$25,000	$25,000
L	Total Indirect Cost	$35,000	$35,000
M	$/kW Net Summer	$280	$269
N	$/kW Net Winter	$260	$252
O	Fuel Expansion	$2,000	$2,000
P	Transmission Expansion	$48,000	$48,000
Q	Railroad & Cars	$0	$0
R	Total Other Cost	$50,000	$50,000
S	Grand Total Cost	$441,596	$441,596
T	$/KW Net Summer	$315	$303
U	$/KW Net Winter	$293	$284
	II. PLANT CHARACTERISTICS		
V	Net Sum 95FCapability (mw)	1,400	1,457
W	Net 75F Capability (mw)	1,506	1,555
	Net 59F Capability (mw)	1,541	1,623
X	Heat Rate btu/kwh 95F100% Load HHV	6,959	6,845
Y	Heat Rate btu/kwh 75F100% Load HHV	6,815	6,777
Y1	Heat Rate btu/kwh 75F 75% Load HHV	6,990	6,951
Y2	Heat Rate btu/kwh 75F 50% Load HHV	7,630	7,587
Z	Heat Rate btu/kwh 59F100% Load HHV	6,783	6,718
AA	Equiv. Avail. %	96%	96%
BB	Sched Outage (wks/yr)	1.5	1.5
CC	Equiv Forced Outage	1.0%	1.0%
	III. OPERATION		
DD	Total O&M (mm/yr)	$8	$8
EE	(remove 6MM for existing fleet cost		
FF	for Repower only)		
GG	Capital Replace ($mm/yr)	$6	$6
	IV. SPENDING CURVES		
HH	Year 6	$0	$0
II	Year 5	$0	$0
JJ	Year 4	$1,766	$1,766
KK	Year 3	$3,091	$3,091
LL	Year 2	$205,784	$205,784
MM	Year 1	$230,955	$230,955
	V. NOTES:		
NN			
	Fuel	New NSC Natural Gas	New NSC Natural Gas
	AFUDC Adder		
OO	Equipment	"7F ++" 6CT & 6HRSG	"7F +++" 6CT & 6HRSG
PP	Cooling	Intake/Discharge	Intake/Discharge
QQ	SCR's	no	no
RR		non-escalated	non-escalated

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-10)
Sanford Comparisons
Page 9 of 17

	New Generation Alternatives		
		20	21
	Alternatives:	Repower PFM Unit 1&2	Repower PSN Unit 3&4
	I. CONSTRUCTION (1000) 1998 $		
A	Permit/Eng/Fab (months)	22	24
B	Construction Phase (months)	25	24
C	Project Total (months)	47	48
D	Land	$ (681)	$ -
E	Materials	$ 291,802	$ 279,521
F	Labor & Equipment	$ 85,450	$ 77,075
G	Total Direct Cost	$ 376,571	$ 356,596
H	Construction Indirects	$ -	$ -
I	Licensing	$ 5,000	$ 5,000
J	Project Support	$ 5,000	$ 5,000
K	Contingency	$ -	$ 25,000
L	Total Indirect Cost	$ 10,000	$ 35,000
M	$/KW Net Summer	$ 263	$ 266
N	$/KW Net Winter	$ 241	$ 244
O	Fuel Expansion	$ 6,000	$ 2,000
P	Transmission Expansion	$ 26,000	$ 48,000
Q	Railroad & Cars	$ -	$ -
R	Total Other Cost	$ 32,000	$ 50,000
S	Grand Total Cost	$ 418,671	$ 441,596
T	$/KW Net Summer	$ 285	$ 300
U	$/KW Net Winter	$ 261	$ 275
	II. PLANT CHARACTERISTICS		
V	Net Sum 95F Capability (mw)	1,470	1,470
V	Net Win 75F Capability (mw)	1,535	1,535
W	Net Win 59F Capability (mw)	1,605	1,605
X	Heat Rate btu/kwh 75F 100% Load HHV	6,795	6,795
Y	Heat Rate btu/kwh 75F 75%	6,830	6,830
Z	Heat Rate btu/kwh 75F 50%	7,450	7,450
AA	Equiv. Avail. %	96%	96%
BB	Sched Outage (wks/yr)	1.5	1.5
CC	Equiv Forced Outage	1.0%	1.0%
	III. OPERATION		
DD	Total O&M (mm/yr)		6.172
EE	Fixed ($/kw - yr)	0.00	1.087
FF	Variable (excl. fuel) ($/mwh)	-	0.370
GG	Capital Replace ($mm/yr)	0.00	12.67
	IV. SPENDING CURVES		
HH	Year 6	$ -	$ -
II	Year 5	$ 5,450	$ -
JJ	Year 4	$ 31,042	$ 38,499
KK	Year 3	$ 227,471	$ 239,984
LL	Year 2	$ 116,227	$ 122,620
MM	Year 1	$ 38,381	$ 40,492
	V. NOTES:	$ 418,571	$ 441,596
NN	Net MW change (summer)	+953 New NSC Incremental O&M	+953 New NSC Incremental O&M
	Equipment Available		2002
OO	Equipment	7F++" 6CT&6HRSG	7F++" 6CT&6HRSG
PP	Cooling	Existing	Existing
QQ	SCR's	no	no
RR	Back-Up Fuel Adder	$ -	$ -

9/14/98
re Bob Burgess

at 35° 1650 mw

6745 at 35°F

60005021

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L. Kollen Exhibit No. ___ (LK-10)
Sanford Comparisons
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	New Generation Alternatives		
		20	21
	Alternatives:	Repower Simple Cycle PFM 1 CT SC	Repower Simple Cycle PSN 1CT SC
	I. CONSTRUCTION (1000) 1998 $		
A	Permit/Eng/Fab (months)		
B	Construction Phase (months)		
C	Project Total (months)		
D	Land		
E	Materials		
F	Labor & Equipment		
G	Total Direct Cost	$ -	$ -
H	Construction Indirects		
I	Licensing		
J	Project Support		
K	Contingency		
L	Total Indirect Cost	$ -	$ -
M	$/KW Net Summer	$ -	$ -
N	$/KW Net Winter	$ -	$ -
O	Fuel Expansion		
P	Transmission Expansion		
Q	Railroad & Cars		
R	Total Other Cost	$ -	$ -
S	Grand Total Cost	$ -	$ -
T	$/KW Net Summer	$ -	$ -
U	$/KW Net Winter	$ -	$ -
	II. PLANT CHARACTERISTICS		
V	Net Sum 95F Capability (mw)	149	149
v	Net Win 75F Capability (mw)	163	163
W	Net Win 59F Capability (mw)	172	172
X	Heat Rate btu/kwh 75F 100% Load HHV	10,450	10,450
Y	Heat Rate btu/kwh 75F 75%	11,280	11,280
Z	Heat Rate btu/kwh 75F 50%	13,500	13,500
AA	Equiv. Avail. %		
BB	Sched Outage (wks/yr)		
CC	Equiv Forced Outage		
	III. OPERATION		
DD	Total O&M (mm/yr)	-	-
EE	Fixed ($/kw - yr)		
FF	Variable (excl. fuel) ($/mwh)		
GG	Capital Replace ($mm/yr)		
	IV. SPENDING CURVES		
HH	Year 6	$ -	$ -
II	Year 5	$ -	$ -
JJ	Year 4	$ -	$ -
KK	Year 3	$ -	$ -
LL	Year 2	$ -	$ -
MM	Year 1	$ -	$ -
	V. NOTES:	$ -	$ -
NN	Net MW change (summer)	New NSC	New NSC
	Equipment Available	2002	2002
OO	Equipment	7F++* Simple Cycle	7F++* Simple Cycle
PP	Cooling	N/A	N/A
QQ	SCR's	no	no
RR	Back-Up Fuel Adder	$ -	$ -

9/14/98 from Bob Burgett

mw
182 at 35° F.

10,220 at 35° F.

60005022

	New Generation Alternatives		
		20	21
	Alternatives:	Repower	Repower
		PFM Unit 1&2	PSN Unit 3&4
	I. CONSTRUCTION (1000) 1998 $		
A	Permit/Eng/Fab (months)	22	24
B	Construction Phase (months)	25	24
C	Project Total (months)	47	48
D	Land	$ (681)	$
E	Materials	$ 291,802	$ 279,521
F	Labor & Equipment	$ 85,450	$ 77,075
G	Total Direct Cost	$ 376,571	$ 356,596
H	Construction Indirects	$ -	$ -
I	Licensing	$ 5,000	$ 5,000
J	Project Support	$ 5,000	$ 5,000
K	Contingency	$ -	$ 25,000
L	Total Indirect Cost	$ 10,000	$ 35,000
M	$/KW Net Summer	$ 263	$ 266
N	$/KW Net Winter	$ 241	$ 244
O	Fuel Expansion	$ 6,000	$ 2,000
P	Transmission Expansion	$ 26,000	$ 48,000
Q	Railroad & Cars	$ -	$ -
R	Total Other Cost	$ 32,000	$ 50,000
S	Grand Total Cost	$ 418,571	$ 441,596
T	$/KW Net Summer	$ 285	$ 300
U	$/KW Net Winter	$ 261	$ 275
	II. PLANT CHARACTERISTICS		
V	Net Sum 95F Capability (mw)	1,470	1,470
v	Net Win 75F Capability (mw)	1,535	1,535
W	Net Win 59F Capability (mw)	1,605	1,605
X	Heat Rate btu/kwh 75F 100% Load HHV	6,795	6,795
Y	Heat Rate btu/kwh 75F 75%	6,830	6,830
Z	Heat Rate btu/kwh 75F 50%	7,450	7,450
AA	Equiv Avail %	96%	95%
BB	Sched Outage (wks/yr)	1.5	1.5
CC	Equiv Forced Outage	1.0%	1.0%
	III. OPERATION		
DD	Total O&M (mm/yr)		6.172
EE	Fixed ($/kw - yr)	0.00	1.087
FF	Variable (excl fuel) ($/mwh)		0.370
GG	Capital Replace ($mm/yr)	0.00	12.67
	IV. SPENDING CURVES		
HH	Year 6	$ -	$ -
II	Year 5	$ 5,450	$ -
JJ	Year 4	$ 31,042	$ 36,499
KK	Year 3	$ 227,471	$ 239,984
LL	Year 2	$ 116,227	$ 122,620
MM	Year 1	$ 38,381	$ 40,492
	V. NOTES:	$ 418,571	$ 441,596
NN	Net MW change (summer)	+953 New NSC Incremental O&M	+953 New NSC Incremental O&M
	Equipment Available		2002
OO	Equipment	7F++" 6CT&6HRSG	7F++" 6CT&6HRSG
PP	Cooling	Existing	Existing
QQ	SCR's	no	no
RR	Back-Up Fuel Adder	$	$

	New Generation Alternatives		
		20	2'
	Alternatives:	Repower Simple Cycle PFM 1 CT SC	Repower Simple Cycle PSN 1CT SC
	I. CONSTRUCTION (1000) 1998 $		
A	Permit/Eng/Fab (months)		
B	Construction Phase (months)		
C	Project Total (months)		
D	Land		
E	Materials		
F	Labor & Equipment		
G	Total Direct Cost	$ -	$ -
H	Construction Indirects		
I	Licensing		
J	Project Support		
K	Contingency		
L	Total Indirect Cost	$ -	$
M	$/KW Net Summer	$ -	$ -
N	$/KW Net Winter	$ -	$ -
O	Fuel Expansion		
P	Transmission Expansion		
Q	Railroad & Cars		
R	Total Other Cost	$ -	$ -
S	Grand Total Cost	$	$
T	$/KW Net Summer	$	$
U	$/KW Net Winter	$ -	$ -
	II. PLANT CHARACTERISTICS		
V	Net Sum 95F Capability (mw)	149	149
v	Net Win 75F Capability (mw)	163	163
W	Net Win 59F Capability (mw)	172	172
X	Heat Rate btu/kwh 75F 100% Load HHV	10,450	10,450
Y	Heat Rate btu/kwh 75F 75%	11,280	11,280
Z	Heat Rate btu/kwh 75F 50%	13,500	13,500
AA	Equiv Avail. %		
BB	Sched Outage (wks/yr)		
CC	Equiv Forced Outage		
	III. OPERATION		
DD	Total O&M (mm/yr)		
	[illegible]		
	[illegible]		
	[illegible]		
	[illegible]	$ -	$ -
		$ -	$ -
		$ -	$ -
		$ -	$ -
		$ -	$ -
		$ -	$ -
	[illegible]	$ -	$ -
NN	Net MW change (summer)	New NSC	New NSC
	Equipment Available	2002	2002
OO	Equipment	7F++*	7F++*
		Simple Cycle	Simple Cycle
		N/A	N/A
		no	no
RR	Back-Up Fuel Adder	$	$

60005024

SUMMARY OF GENERATION ALTERNATIVES
COST AND COMPETITION TEAM
IRP 1998

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-10)
Sanford Comparisons

	New Generation Alternatives					
		18	19	20	21	21A
	Alternatives:	200 SC	500 CC - F++	Repower	Repower	Repower
		Exist Site - "G"	Greenfield	PFM Unit 1&2	PSN Unit 3&4	PSN Unit 3&4
	I. CONSTRUCTION (1000) 1998 $					
A	Permit/Eng/Fab (months)	19	24	22	24	24
B	Construction Phase (months)	6	24	26	24	24
C	Project Total (months)	15	48	47	48	48
			$ 1,200	$ (681)	$ -	$ -
E	Materials	$ 42 059	$ 120,000	$ 291,802	$ 279 521	$ 279 521
F	Labor & Equipment	$ 6 333	$ 44,000	$ 85,450	$ 77,075	$ 77 075
G	Total Direct Cost	$ 48 402	$ 165,200	$ 376,571	$ 356,596	$ 356,596
H	Construction Indirects	$ -	-	$ -	$ -	$
I	Licensing	$ 400	$ 3,200	$ 5 000	$ 5,000	$ 5,000
J	Project Support	$ 1,090	$ 2,700	$ 5,000	$ 5 000	$ 5,000
K	Contingency	$ 249	$ 6,844	$ -	$ 25 000	$ 25,000
L	Total Indirect Cost	$ 1 739	$ 12,744	$ 10,000	$ 35,000	$ 35,000
			378	$ 278	$ 281	$
			350	$ 252	$ 255	$
O	Fuel Expansion	$ 200	$ 4,000	$ 6,000	$ 2,000	$ 2,000
P	Transmission Expansion	By Others	$ 13,000	$ 26,000	$ 46,000	$ 46,000
Q	Railroad & Cars	$	$ -	$ -	$ -	$ -
R	Total Other Cost	$ 200	$ 17,000	$ 32,000	$ 50,000	$ 50,000
S	Grand Total Cost	$ 50,341	$ 194,944	$ 418,571	$ 441,596	$ 441,596
T	$/KW Net Summer	$ 241	$ 414	$ 300	$ 317	$ 314
U	$/KW Net Winter	$ 212	$ 383	$ 273	$ 288	$ 285
	II. PLANT CHARACTERISTICS					
	Net Sum 95F Capability (mw)	209	471	1,393	1,393	1,407
V	Net Win 75F Capability (mw)	224	491	1,499	1,499	1,514
W	Net Win 59F Capability (mw)	237	509	1,534	1,534	1,549
X	Heat Rate btu/kwh 75F 100% Load HHV	10,010	6,802	6,802	6,802	6,768
Y	Heat Rate btu/kwh 75F 75%	10,915	6,832	6,832	6,832	6,798
Z	Heat Rate btu/kwh 75F 50%	11,875	7,458	7,458	7,456	7,421
AA	Equiv Avail %	98%	96%	96%	96%	96%
BB	Sched Outage (wks/yr)	0.5	1.5	1.5	1.5	1.5
CC	Equiv Forced Outage	1 0%	1 0%	1.0%	1 0%	1.0%
	III. OPERATION					
DD	Total O&M (mm/yr)	0.64	4.70	[illegible]	5.849	5.924
EE	Fixed ($/kw - yr)	0.51	4.95	0 00	1.087	1.065
FF	Variable (excl fuel) ($/mwh)	0.295	0.598	-	0.370	0.374
GG	Capital Replace ($mm/yr)	1.50	4 44	0 00	12 67	12.73
	IV. SPENDING CURVES					
HH	Year 6	$ -	$ -	$ -	$ -	$ -
II	Year 5	$ -	$ -	$ 5,450	$ -	$ -
JJ	Year 4	$ -	$ 780	$ 31,042	$ 38,499	$ 38,499
KK	Year 3	$ -	$ 1,365	$ 227,471	$ 239,984	$ 239,984
LL	Year 2	$ 17,620	$ 90,844	$ 116,227	$ 122,620	$ 122,620
MM	Year 1	$ 32,722	$ 101,956	$ 38,381	$ 40,492	$ 40,492
	V. NOTES:	$ 50,341	$ 194,944	$ 418,571	$ 441,596	$ 441,596
NN	Net MW change (summer)	+209	+471	+953	+953	+967
		New NSC	New NSC	New NSC	New NSC	New NSC
				Incremental O&M	Incremental O&M	Incremental O&M
	Equipment Available				2002	2004
OO	Equipment	1-CT - "G"	7F++*	7F++*	7F++*	7F+++*
			2CT&2HRSG&1ST	6CT&6HRSG	6CT&6HRSG	6CT&6HRSG
PP	Cooling	Existing	Tower	Existing	Existing	Existing
QQ	SCR's	no	no	no	no	no
RR	Back-Up Fuel Adder	$ 2,500	$ 3,500	$ -	$	$

60005025

APRIL 9, 1999

SUMMARY OF GENERATION ALTERNATIVES
IRP 1999

	New Generation Alternatives						
		14	15	16	17	18	19
	Alternatives:	400 CFB	400 CFB	400 PC	400 PC	150 SC - F	500 CC - F
						Simple Cycle	7241
		Greenfield	Martin	Greenfield	Martin	Existing Site	Greenfield
	I. CONSTRUCTION (1000) 1999 $						
A	Permit/Eng/Fab (months)	33	30	36	30	9	24
B	Construction Phase (months)	30	27	30	27	6	24
C	Project Total (months)	63	57	[illegible]	57	15	[illegible]
D	Land	$ 1,210	$ -	$ 1,210	$ -	$ -	$ 1,200
E	Materials	$ 224,210	$ 224,210	$ 226,000	$ 224,000	$ 32,000	$ 120,000
F	Labor & Equipment	$ 95,586	$ 95,586	$ 104,000	$ 104,000	$ 10,000	$ 44,000
G	Total Direct Cost	$ 321,006	$ 319,796	$ 331,210	$ 328,000	$ 42,000	$ 165,200
H	Construction Indirects	$ -	$ -	$ -	$ -	$ -	$ -
I	Licensing	$ 6,000	$ 5,500	$ 6,000	$ 5,500	$ 400	$ 3,200
J	Project Support	$ 4,100	$ 3,608	$ 4,220	$ 3,616	$ 250	$ 2,700
K	Contingency	$ 10,244	$ 8,512	$ 10,657	$ 8,799	$ 500	$ 6,844
L	Total Indirect Cost	$ 20,344	$ 17,620	$ 20,877	$ 17,915	$ 1,150	$ 12,744
M	$/KW Net Summer	$ 853	$ 844	$ 880	$ 865	$ 290	$ 363
N	$/KW Net Winter	$ 849	$ 839	$ 876	$ 860	$ 251	$ 335
O	Fuel Expansion	$ -	$ -	$ -	$ -	By Others	$ -
P	Transmission Expansion	By Others	By Others	By Others	By Others	By Others	By Others
Q	Railroad & Cars	$ 8,000	$ 8,000	$ 8,000	$ 8,000		$ -
R	Total Other Cost	$ 8,000	$ 8,000	$ 8,000	$ 8,000	$ -	$ -
S	Grand Total Cost	$ 349,350	$ 345,416	$ 360,087	$ 353,915	$ 43,150	$ 177,944
T	$/KW Net Summer	$ 873	$ 864	$ 900	$ 885	$ 290	$ 363
U	$/KW Net Winter	$ 869	$ 859	$ 896	$ 880	$ 251	$ 335
	II. PLANT CHARACTERISTICS						
V	Net Sum 95F Capability (mw)	400	400	400	400	149	490
v	Net Win 75F Capability (mw)	401	401	401	401	163	510
W	Net Win 59F Capability (mw)	402	402	402	402	172	532
X	Heat Rate btu/kwh 75F 100% Load HHV	9,600	9,600	9,500	9,500	10,450	6,830
Y	Heat Rate btu/kwh 75F 75%	9,700	9,700	9,600	9,600	11,280	7,171
Z	Heat Rate btu/kwh 75F 50%	10,200	10,200	10,100	10,100	13,500	7,718
AA	Equiv. Avail. %	97%	97%	97%	97%	98%	96%
BB	Sched Outage (wks/yr)	1.0	1.0	1.0	1.0	0.5	1.5
CC	Equiv Forced Outage	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
	III. OPERATION					10% Capacity Cap	
DD	Total O&M (mm/yr)	11.25	9.37	12.91	11.03	0.18	4.59
EE	Fixed ($/kw - yr)	15.40	10.70	18.66	13.96	0.72	5.18
FF	Variable (excl fuel) ($/mwh)	1 497	1 497	1 603	1.603	0.59	0.50
GG	Capital Replace ($mm/yr)	2.00	2.00	3 00	3 00	0.00	3.32
	IV. SPENDING CURVES						
HH	Year 6	$ 1,397	$ -	$ 1,440	$ -	$ -	$ -
II	Year 5	$ 6,987	$ 5,872	$ 7,202	$ 6,724	$ -	$ -
JJ	Year 4	$ 8,384	$ 8,290	$ 8,642	$ 8,494	$ -	$ 712
KK	Year 3	$ 60,088	$ 61,829	$ 61,935	$ 62,643	$ -	$ 1,246
LL	Year 2	$ 95,023	$ 93,953	$ 97,944	$ 96,265	$ 15,103	$ 82,922
MM	Year 1	$ 177,470	$ 175,471	$ 182,924	$ 179,789	$ 28,048	$ 93,065
	V. NOTES:	$ 349,350	$ 345,416	$ 360,087	$ 353,915	$ 43,150	$ 177,944
NN	Net MW change (summer)	+400	+400	+400	+400	+149	+490
		New NSC	New NSC	New NSC	New NSC	New NSC	New NSC
	Equipment Available					2002	
OO	Equipment	1CFB	1CFB	PC	PC	7F 7241	7F 7241 Foggers
						Simple Cycle	2CT&2HRSG&1ST
PP	Cooling	Tower	Reservoir	Tower	Reservoir	N/A	Tower
QQ	SCR's	yes - SNCR	yes - SNCR	yes - SCR	yes - SCR	no	no
RR	Back-Up Fuel Adder	$ 3,000	$ 3,000	$ 3,000	$ 3,000	Included	$ 3,500

ok

60005026

SUMMARY OF GENERATION ALTERNATIVES
IRP 1999

	New Generation Alternatives					
		20	21A	21B	22	[illegible]
	Alternatives:	Repower	Repower	Repower	400 CC - ATS	[illegible] G
		PFM Unit 1&2	PSN Unit 4	PSN Unit 5	Ft. Myers	Ft. Myers
	I. CONSTRUCTION (1000) 1999 $					
A	Permit/Eng/Fab (months)	5	10	10	[illegible]	[illegible]
B	Construction Phase (months)	28	28	28	19	19
C	Project Total (months)	33	38	38	[illegible]	[illegible]
D	Land	$ -			$ -	$ -
E	Materials	$ 285,148	$ 175,231	$ 175,231	$ [illegible]	$ [illegible]
F	Labor & Equipment	$ 111,342	$ 68,866	$ 68,866	$ [illegible]	$ [illegible]
G	Total Direct Cost	$ 396,489	$ 244,097	$ 244,097	$ 158,000	$ 114,000
H	Construction Indirects	$ -	$ -	$ -	$ -	$ -
I	Licensing	$ 5,282	$ 2,605	$ 2,605	$ 3,600	$ 3,600
J	Project Support	$ 5,865	$ 3,079	$ 3,079	$ 2,700	$ 2,700
K	Contingency	$ 5,284	$ 11,118	$ 11,118	$ [illegible]	$ 4,560
L	Total Indirect Cost	$ 16,432	$ 16,802	$ 16,802	$ 10,672	$ 10,660
M	$/KW Net Summer	$ 281	$ 268	$ 268	$ 434	$ 400
N	$/KW Net Winter	$ 259	$ 251	$ 251	$ [illegible]	$ 352
O	Fuel Expansion	$ -	$ -	$ -	By Others	By Others
P	Transmission Expansion	$ 27,906	$ 39,832	$ 39,832	By Others	By Others
Q	Railroad & Cars	$ -	$ -	$ -	$ -	$ -
R	Total Other Cost	$ 27,906	$ 39,832	$ 39,832	$ -	$
S	Grand Total Cost	$ 440,827	$ 300,731	$ 300,731	$ 170,872	$ 124,860
T	$/KW Net Summer	$ 300	$ 308	$ 308	$ 434	$ 400
U	$/KW Net Winter	$ 276	$ 290	$ 290	$ 396	$ 352
	II. PLANT CHARACTERISTICS					
V	Net Sum 95F Capability (mw)	1,470	975	975	394	312
v	Net Win 75F Capability (mw) "The winter capability 1625 MW?"	1,530	1,017	1,017	410	336
W	Net Win 59F Capability (mw)	1,595	1,038	1,038	429	355
X	Heat Rate btu/kwh 75F 100% Load HHV	6,830	6,860	6,860	6,346	6,675
Y	Heat Rate btu/kwh 75F 75%	7,171	7,203	7,203	6,599	7,010
Z	Heat Rate btu/kwh 75F 50%	7,718	7,752	7,762	7,297	7,710
AA	Equiv Avail %	96%	95%	96%	95%	96%
BB	Sched Outage (wks/yr)	1.5	1.5	1.5	1.5	1.5
CC	Equiv Forced Outage	1.0%	1.0%	1.0%	1.0%	1.0%
	III. OPERATION					
DD	Total O&M (mm/yr)	9.55	6.21	6.21	3.89	3.37
EE	Fixed ($/kw - yr)	3.40	3.08	3.08	3.67	4.89
FF	Variable (excl. fuel) ($/mwh)	0.368	0.39	0.39	0.71	0.70
GG	Capital Replace ($mm/yr)	9.20	6.33	6.33	3.51	2.59
	IV. SPENDING CURVES					
HH	Year 6	$ -	$ -	$ -	$ -	$ -
II	Year 5	$ 10,304	$ 31,400	$ 31,400	$ -	$ -
JJ	Year 4	$ 148,505	$ 119,450	$ 119,450	$ 683	$ 499
KK	Year 3	$ 138,864	$ 91,714	$ 91,714	$ 1,196	$ 874
LL	Year 2	$ 117,147	$ 42,096	$ 42,096	$ 79,626	$ 58,185
MM	Year 1	$ 26,007	$ 16,004	$ 16,004	$ 89,366	$ 65,302
	V. NOTES:	$ 440,827	$ 300,663	$ 300,663	$ 170,872	$ 124,860
NN	Net MW change (summer)	+953 New NSC	+607 New NSC	+607 New NSC	+394 New NSC	+312 New NSC
	Equipment Available				2003-2005	2000+
OO	Equipment	7F 7241 Foggers 6CT&6HRSG	7F 7241 Foggers 4CT&4HRSG	7F 7241 Foggers 4CT&4HRSG	ATS - "H" 1CT & 1HRSG	"G" 1CT & 1HRSG
PP	Cooling	Existing	Existing	Existing	Towers	Towers
QQ	SCR's	no	no	no	no	no
RR	Back-Up Fuel Adder	$ -	$ -	$ -	$ 3,500	$ 3,500

60005027

	New Generation Alternatives	7	8	9	10	11	12	13
	Alternatives:	600 CC - G	600 CC - G	500 CC - F 7241	500 CC - F 7241	150 SC - F Simple Cycle	400 CFB	400 CFB
		Greenfield	Existing Site	Greenfield	Existing Site	Existing Site	Greenfield	Mar
	I. CONSTRUCTION (1000) 2000 $							
A	Permit/Eng/Fab (months)	24	20	24	24	12	33	30
B	Construction Phase (months)	24	24	24	24	11	30	27
C	Project Total (months)	48	44	48	48	23	63	57
D	Land	$1,200	$0	$1,200	$0	$0	$1,200	$0
E	Materials	$245,218	$242,548	$135,000	$130 500	$38,313	$257,000	$257 000
F	Labor & Equipment	$51 403	$47,667	$41,017	$32,817	$8 638	$117,460	$117 380
G	Total Direct Cost	$297,821	$290,215	$177,217	$163,317	$46,951	$375,660	$374,380
H	Construction Indirects	$0	$0	$0	$0	$0	$0	$0
I	Licensing	$2 500	$2,000	$2,500	$2,000	$600	$6,000	$5,500
J	Project Support	$20,500	$19,900	$12,628	$12,028	$2,777	$4,100	$3,633
K	Contingency	$16 041	$12 485	$7,694	$7,094	$503	$10,244	$8,512
L	Total Indirect Cost	$39,041	$34,385	$22,822	$21,122	$3,880	$20,344	$17,633
M	$/KW Net Summer	$545	$525	$416	$383	$330	$990	$980
N	$/KW Net Winter	$485	$468	$378	$349	$298	$985	$975
O	Fuel Expansion	By Fuels	By Fuels	By Fuels	By Fuels	By Fuels	$0	$0
P	Transmission Expansion	By Pwr Deliv	By Pwr Deliv	By Pwr Deliv	By Pwr Deliv	By Pwr Deliv	By Pwr Deliv	By Pwr Deliv
Q	Railroad & Cars	$0	$0	$0	$0		$8,000	$8,000
R	Total Other Cost	$0	$0	$0	$0	$0	$8,000	$8,000
S	Grand Total Cost	$336,862	$324,600	$200,039	$184,439	$50,831	$404,004	$400,000
T	$/KW Net Summer	$545	$525	$416	$383	$330	$1,010	$1,000
U	$/KW Net Winter	$485	$468	$378	$349	$295	$1,005	$995
	II. PLANT CHARACTERISTICS							
	Net Sum 95F Capability (mw)	618	618	481	481	154	400	400
V	Net Win 75F Capability (mw)	663	663	512	512	165	401	401
W	Net Win 59F Capability (mw)	694	694	529	529	172	402	402
	Heat Rate btu/kwh 75F 100% Load HHV	6,773	6,773	6,773	6,773	10,450	9,700	9,700
Y	Heat Rate btu/kwh 75F 75%	6,964	6,964	6,964	6,964	11,390	9,800	9,800
Z	Heat Rate btu/kwh 75F 50%	7,464	7,464	7,464	7,464	13,720	10,300	10,300
AA	Equiv. Avail. %	96%	96%	96%	96%	98%	89%	89%
BB	Sched Outage (wks/yr)	1.5	1.5	1.5	1.5	0.5	4.0	4.0
CC	Equiv Forced Outage	1.0%	1.0%	1.0%	1.0%	1.0%	3.0%	3.0%
	III. OPERATION					10% Capacity Cap		
DD	Total O&M (mill/yr)	7.80	5.45	4.68	3.24	20.22	10.83	8.95
EE	Fixed ($/kw - yr)		2.14	5.12	2 54	0 66	15 40	10.70
		59% / 41%	26% / 74%	59% / 41%	26% / 74%	0% / 100%	80% / 20%	74% / 26%
		0.99		0 55	0 55	0 86	1.50	1.50
				33% / 67%	33% / 67%	0% / 100%	11% / 89%	11% / 89%
				3 66	3 86	0 00	2.00	2.00
HH	Year 6	$0	$0	$0	$0	$0	$1,397	$0
II	Year 5	$0	$0	$0	$0	$0	$11,637	$10,456
JJ	Year 4	$4,379	$4,220	$2,601	$2,398	$0	$13,384	$13,290
KK	Year 3	$110,491	$106,469	$65,613	$60,498	$0	$70,088	$71,829
LL	Year 2	$181,906	$175,284	$108,021	$99 597	$25,924	$110,023	$108,953
MM	Year 1	$40,067	$38 627	$23,805	$21 948	$24 907	$197,471	$195,472
	V. NOTES:							
NN	Net MW change (summer)	+618	+618	+481	+481	+154	+400	+400
		New NSC	New NSC	New NSC	New NSC	New NSC	New NSC	New NSC
	Plant Life Years	30	30	30	30	30	30	30
	Equipment Available	2000+	2000+			2002		
OO	Equipment	"G"	"G"	7F 7241 Foggers	7F 7241 Foggers	7F 7241	1CFB	1CFB
		2CT & 2HRSG	2CT & 2HRSG	2CT&2HRSG&1ST	2CT&2HRSG&1ST	Simple Cycle		
PP	Cooling	Tower	Tower	Tower	Tower	N/A	Tower	Reservoir
		YES	YES	no	no	no	yes - SNCR	yes - SNCR
		$7,000	$7,000	$5,500	$5,500	Included	$3,000	$3,000

SUMMARY OF GENERATION ALTERNATIVES
IRP 2000

	New Generation Alternatives	14	15	16	17	18	[illegible]
	Alternatives:	400 PC	400 PC	CC - F	100% Pet Coke	100% Pet Coke	[illegible]
				Repower	Fuel Switch	Fuel Switch	[illegible]
		Greenfield	Martin	400mw Unit	Riviera	Martin	Manatee
	I CONSTRUCTION (1000) 2000 $						
A	Permit/Eng/Fab (months)	36	30	10	18	30	[illegible]
B	Construction Phase (months)	30	27	28	30	34	4
C	Project Total (months)	66	57	38	48	64	4
D	Land	$1,200	$0	$0	$0	$0	$0
E	Materials	$260,038	$257,400	$212,644	$483,500	$587,500	$2,000
F	Labor & Equipment	$126,685	$126,300	$68,141	Included Above	Included Above	$1,000
G	Total Direct Cost	$387,923	$383,700	$280,785	$483,500	$587,500	$3,000
H	Construction Indirects	$0	$0	$16,746	$0	$0	$0
I	Licensing	$6,000	$5,500	$2,826	$6,000	$11,000	$0
J	Project Support	$4,220	$3,601	$8,952	$5,000	$9,000	$250
K	Contingency	$10,657	$8,799	$0	$10,000	$35,377	$114
L	Total Indirect Cost	$20,877	$17,900	$30,524	$21,000	$55,377	$364
M	$/KW Net Summer	$1,022	$1,004	$319	$864	$403	
N	$/KW Net Winter	$1,017	$999	$300	$858	$399	
O	Fuel Expansion	$0	$0	By Fuels	$0	$0	By Fuels
P	Transmission Expansion	By Pwr Deliv	By Pwr Deliv	By Pwr Deliv	$0	$0	$0
Q	Railroad & Cars	$8,000	$6,000	$0	Use Port	$0	$0
R	Total Other Cost	$8,000	$6,000	$0	$0	$0	$0
S	Grand Total Cost	$416,800	$409,600	$311,309	$504,500	$642,877	$3,364
T	$/KW Net Summer	$1,042	$1,024	$319	$864	$403	[illegible]
U	$/KW Net Winter	$1,037	$1,019	$300	$858	$399	[illegible]
	II PLANT CHARACTERISTICS						
V	Net Sum 95F Capability (mw)	400	400	975	584	1,594	[illegible]
v	Net Win 75F Capability (mw)	401	401	1,017	586	1,606	
W	Net Win 59F Capability (mw)	402	402	1,039	588	1,612	
	Heat Rate btu/kwh 75F 100% Load HHV	9,850	9,850	6,660	9,974	9,500	10,768
Y	Heat Rate btu/kwh 75F 75%	9,950	9,950	7,203	10,054	9,600	10,707
Z	Heat Rate btu/kwh 75F 50%	10,500	10,500	7,752	10,141	10,100	10,867
AA	Equiv Avail %	89%	89%	96%	87%	94%	
BB	Sched Outage (wks/yr)	4.0	4.0	1.5	5.0	2.0	
CC	Equiv Forced Outage	3.0%	3.0%	1.0%	3.0%	2.0%	
	III OPERATION						
DD	Total O&M (mm/yr)	2.46	10.59	5.21	24.34	16.46	[illegible]
EE	Fixed ($/kw - yr)	18.66	13.96	3.08	18.13	5.93	
	% Manpower/ % Material, Equip	84% / 16%	80% / 20%	59% / 41%	80% / 20%	70% / 30%	
FF	Variable (excl fuel) ($/mwh)	1.60	1.60	0.39	3.09	0.53	
	% Manpower/ % Material, Equip	11% / 89%	11% / 89%	35% / 65%	11% / 89%	11% / 89%	
GG	Capital Replace ($mm/yr)	3.00	3.00	6.33	2.00	6.00	
	IV. SPENDING CURVES						
HH	Year 6	$1,440	$0	$44	$0	$2,572	$0
II	Year 5	$13,915	$12,409	$27,963	$0	$12,859	$0
JJ	Year 4	$13,642	$13,494	$159,042	$25,225	$15,429	$0
KK	Year 3	$71,935	$72,643	$57,265	$90,810	$110,575	$0
LL	Year 2	$112,944	$111,265	$29,377	$136,215	$174,862	$0
MM	Year 1	$202,924	$199,789	$7,617	$252,250	$326,560	$3,364
	V NOTES:						$3,364
NN	Net MW change (summer)	+400	+400	+607	+0	+0	+0
		New NSC	New NSC	New NSC			
	Plant Life Years	30	30	30	30	30	
	Equipment Available						
OO	Equipment	PC	PC	7F 7241 Foggers 4CT&4HRSG	2 CFB	4 Conv Boilers Leased Bk End	Existing
PP	Cooling	Tower	Reservoir	Existing	Tower	Reservoir	Reservoir
	SCR's	yes - SCR	yes - SCR	no	yes - SNCR	yes - SCR	No
RR	Back-Up Fuel Adder	$3,000	$3,000	$0	$0	$0	$0

Ft Myers and Sanford Repowering Projects
5-YearForecast Differences ... October 1998 - August 1999

Ft Myers Repowering ... Power Generation

	5-year Forecasts October 1998	5-year Forecasts August 1999	Change
1998	$10 101,000	$10,388,000	$287,000
1999	$147 905,000	$149,015,000	$1,110,000
2000	$117,416,000	$191,624,000	$74,208,000
2001	$118.434,000	$49,151,000	($69,283,000)
2002	$27,668,000	$18,395,000	($9,273,000)
2003	$0	$5,501,000	$5.501,000
Total Forecast	**$421,524,000**	**$424,074,000**	**$2,550,000**

Sanford Repowering ... Power Generation

	5-year Forecasts October 1998	5-year Forecasts August 1999	Change
1998	$787,000	$88,000	($699,000)
1999	$62,384,000	$55,805,000	($6,579,000)
2000	$156,519,000	$271,953,000	$115,434,000
2001	$91,181,000	$144,395,000	$53,214,000
2002	$95,085,000	$58,609,000	($36,476,000)
2003	$31,451,000	$15,217,000	($16,234,000)
Total Forecast	**$437,407,000**	**$546,067,000**	**$108,660,000**

8 SA's x 6 92 _ [illegible]

10/30/98

FPL POWER GENERATION BUSINESS UNIT
SANFORD PLANT REPOWERING
(FPL BUDGET ACTIVITY # 722)
1999 Five-Year Capital Forecast
October 29, 1998
TOTAL PROJECT (BA-722)

	TOTAL	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
POWER GENERATION BUSINESS UNIT													
1998 (Prior Year)	$787,345									$5,000	$42,039	$311,090	$429,216
1999	$62,383,976	$394,924	$634,908	$4,935,741	$526,453	$867,122	$9,663,142	$523,019	$1,262,605	$11,993,815	$11,993,815	$8,680,824	$10,907,607
2000	$156,518,801	$13,296,207	$15,799,811	$11,023,210	$11,023,210	$10,926,739	$21,530,759	$12,899,560	$12,815,672	$13,308,730	$13,997,550	$9,508,999	$10,388,353
2001	$91,181,096	$7,919,951	$7,928,465	$4,379,405	$6,700,309	$8,849,559	$10,146,627	$9,179,818	$6,956,786	$7,456,786	$7,456,786	$6,780,854	$7,425,752
2002	$95,085,019	$10,864,522	$7,294,904	$6,763,037	$8,742,583	$10,590,344	$8,717,671	$10,342,731	$11,599,450	$7,275,422	$4,968,702	$3,184,228	$4,741,426
2003	$31,450,764	$3,181,536	$1,925,804	$1,484,199	$1,413,582	$1,383,062	$1,149,950	$1,163,582	$16,115,980	$1,211,023	$1,211,023	$1,211,023	$0
2004(After)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sub-Total PGBU	$437,407,000												
OTHER DEPTS (Power Delivery)													
1998 (Prior Year)	$0									$0	$0	$0	$0
1999	$3,500,000	$22,000	$22,000	$22,000	$22,000	$22,000	$22,000	$22,000	$22,000	$22,000	$1,522,000	$892,000	$888,000
2000	$15,200,000	$1,820,000	$1,820,000	$1,820,000	$1,820,000	$95,000	$95,000	$95,000	$95,000	$100,000	$2,500,000	$2,500,000	$2,440,000
2001	$36,153,000	$3,335,000	$3,335,000	$3,335,000	$3,335,000	$3,335,000	$2,063,000	$1,792,000	$6,900,000	$0	$600,000	$7,523,000	$600,000
2002	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2003	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2004(After)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Sub-Total Other Depts	$54,853,000												

TOTAL PROJECT COST $\boxed{\$492,260,000}$
(Excluding AFUDC)

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-12)
Sanford Transmission Facilities Cost
10/29/98

00421520

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-13)
7/28/00 Sanford Cost Estimate

SANFORD REPOWERING PROJECT

CURRENT RANGE OF ESTIMATES AT COMPLETION

B&V PCR#12 - July 28, 2000

	Project Cost Est W/O Project Contingency	FPL Current Budget ("50/50 Estimate")	B&V Max Performance Estimate	B&V Worst-Case Estimate
Awarded Cost To-date (excl B&V performance incentive)	$435,882,081	$435,882,081	$435,882,081	$435,882,081
B&V Allocated & Trended Contingencies on Awarded Cost (details attached)	$16,424,464	$16,424,464	$16,424,464	$16,424,464
Un-Awarded Major Contracts (see "major commitments listing")	$62,704,655	$62,704,655	$62,704,655	$62,704,655
Un-Spent / Un-Awarded Balance-of-Project Estimate	$15,157,321	$15,157,321	$15,157,321	$15,157,321
Project Cost Estimate (PCE) for B&V Scope	$530,168,521	$530,168,521	$530,168,521	$530,168,521
FPL - Transmission Interconnections	$75,383,000	$75,383,000	$75,383,000	$75,383,000
FPL - Demolition & Abatement	$8,000,000	$8,000,000	$8,000,000	$8,000,000
FPL - B&V Performance Incentive	$4,000,000	$4,000,000	$4,000,000	$0
FPL - Maintenance Building / Geotech / Other	$900,000	$900,000	$900,000	$900,000
FPL - FGT Fuel Gas Equipment Reimbursement	$0	$0	$0	$0
FPL - Schedule Revisions ... Pending Cost Impacts	$0	$0	$0	$0
FPL - Project Contingency	$0	$3,548,479	$18,450,957	$28,450,957
TOTAL PROJECT ESTIMATES	$618,451,521	$622,000,000	$636,902,478	$642,902,478
TOTAL CONTINGENCIES INCLUDED IN THE ESTIMATES ABOVE	*$16,424,464*	*$19,972,943*	*$34,875,421*	*$44,875,421*

SANFORD REPOWERING SUCCESS CRITERIA

SAFETY

- PLANT DESIGN INCORPORATES SAFETY AND ERGONOMICS
- OSHA RECORDABLE RATE DURING CONSTRUCTION AND OPERATION - 0
- NO TRAFFIC ACCIDENTS AT BARWICK AND FORT FLORIDA ROAD INTERSECTIONS TO 17/92

ENVIRONMENTAL

- Nox - 9 ppm (30 DAY ROLLING HOURLY AVERAGE)
- CO - 12ppm (30 DAY ROLLING HOURLY AVERAGE)
- NOISE (AT "NEAREST RECEPTOR")
  - 60dB DAY (7am-10pm)
  - 55dB NIGHT (10pm-7am)
- NO NON COMPLIANCES DURING CONSTRUCTION

OPERATING*

- NET OUTPUT PER UNIT - 1009 MW (75F FOGGED)
- SINGLE EVENT LOAD LOSS
  - LESS THAN 910 MW
  - HOLD LEVEL FOR 10 MINS
  - DESIGNED TO HOLD LEVEL FOR 30 MINS
- TURNDOWN - 480 TO 1009 MW ON CONTROL
  - 280 MW MINIMUM IF CT'S CYCLE OFF
- RAMP RATE - 15 MW/MIN
- START UP DURATION TO ON-CONTROL @ 480 MW
  (30MW 1HR AFTER START, RAMPING TO 480 MW)
  - COLD - 12 HRS
  - WARM - 8 HRS
- AVAILABILITY TARGETS
  - EAF - 96%
  - POF - 2.8% (SEE O&M CRITERIA)
  - EFOR - 1.2%
- HEAT RATE - 6910 BTU/KWH HHV (75F FOGGED)
- DESIGN MUST FACILITATE PERFORMANCE TESTING AND PERFORMANCE MONITORING

FINANCIAL

- PROJECT COST - $622M
- ECONOMIC DECISION CRITERIA (LOWEST LIFE CYCLE COST)
  - NPV TERM - 5 YEARS
  - HEAT RATE VALUE - 1BTU/KWH=$128K
  - CAPACITY VALUE - 1KW=$200
  - EAF VALUE - 1%=$4M
  - O&M VALUE - $100K ANNUAL =$425K NPV

O & M*

- CT OUTAGE FREQ/DURATIONS (BREAKER TO BREAKER - PMR BASED)
  - COMBUSTION - 12 KHRS/6.5 DAYS
  - HOT GAS PATH - 24 KHRS/13 DAYS
  - MAJOR - 48 KHRS/24 DAYS
- STM TURB FREQ/DURATIONS
  - UNIT #4 - CTYR 2011/60 DAYS
  - UNIT #5 - CTYR 2010/60DAYS
- ON SITE STAFFING APPROX - 48 to 54
- ANNUAL BUDGET
  - CT OVERHAUL BUDGET - $16M
  - O&M - $5M

SCHEDULE

- STEAM UNITS OFF ON:
  - UNIT#4- 3/15/02
  - UNIT#5- 10/15/01
- GENERATION AVAILABLE BY:
  - UNIT#4- 12/31/02
  - UNIT#5- 6/30/02
- COST OF EACH DAY'S DELAY
  - $250K/DAY REPLACEMENT PWR COSTS (500 MW)
  - $2M/MO CAPACITY CONTRACT (500 MW) FOR 15% RESERVES

* PRELIMINARY ESTIMATES

1/11/00

5/9/01

POWER GENERATION DIVISION CASHFLOW RECAP

MAY 7, 2001 FIVE-YEAR FORECAST vs CURRENT APPROVED PGD PLAN

	2000 & PRIOR	2001	2002	2003 & AFTER	TOTAL PGD
MAY 7, 2001 FORECASTS					
FORT MYERS REPOWERING	$362,439,397	$71,504,449	$21,004,755	$2,353,940	$457,302,541
SANFORD REPOWERING	$316,993,939	$165,103,849	$63,468,767	$15,737,515	$561,304,070
MARTIN SIMPLE CYCLE	$77,679,471	$21,395,007	$1,320,048	$0	$100,394,526
FORT MYERS SIMPLE CYCLE	$2,239,641	$32,469,339	$78,378,858	$19,393,317	$132,481,355
PROJECTS TOTAL EXPENDITURES		$290,472,644	$164,172,428	$37,484,772	
CURRENT APPROVED 5-YEAR FORECASTS					
FORT MYERS REPOWERING		$71,533,736	$14,943,298	$5,223,111	Demo Begins Jan 2003
SANFORD REPOWERING		$156,503,028	$57,764,805	$15,216,889	B&V Final Pmt of $4m Payable in 2003
MARTIN SIMPLE CYCLE		$28,832,157	$1,108,281	$0	
FORT MYERS SIMPLE CYCLE		$34,014,400	$75,014,402	$21,510,413*	
PROJECTS TOTAL EXPENDITURES		$290,883,319	$148,830,786	$41,950,413	* Incl $1,279 in 2004
FORECAST DIFFERENCE TO APPROVED PLAN					
FORT MYERS REPOWERING		($29,287)	$6,061,457	($2,869,171)	Demo Begins June 2002
SANFORD REPOWERING		$8,600,823	$5,703,962	$520,626	B&V Final Pmt of $4m Payable Jan 1,2003
MARTIN SIMPLE CYCLE		($7,437,150)	$211,767	$0	
FORT MYERS SIMPLE CYCLE		($1,545,061)	$3,364,456	($2,117,096)	CTG Payments Complete on Shipment(2002)
PROJECTS TOTAL EXPENDITURES		($410,675)	$15,341,642	($4,465,641)	

2002 MONTHLY FORECAST OF BILLED SALES, CUSTOMERS AND USE BY CLASS

	January	February	March	April	May	June	July	August	September	October	November	December	2002 Budget Forecast Total
SYSTEM SALES (mWh)													
Residential	3,874,869	3,762,017	3,257,987	3,539,325	3,629,189	4,763,609	4,990,310	5,203,464	5,237,201	4,832,118	3,720,704	3,768,114	50,578,908
Commercial	2,962,447	2,950,731	2,965,590	3,098,643	3,191,730	3,478,689	3,588,209	3,633,945	3,727,163	3,427,258	3,186,861	3,302,852	39,514,116
Industrial	337,106	336,413	340,075	339,639	339,318	338,800	338,648	338,576	338,141	338,461	338,292	338,155	4,061,622
Street & Highway	35,318	35,389	35,494	35,563	35,631	35,732	35,798	35,863	35,961	36,025	36,087	36,182	429,045
Other	4,363	4,731	4,614	4,890	5,083	5,670	5,953	5,870	5,970	5,024	5,203	4,987	62,359
Railroads & Railways	6,909	6,913	6,920	6,925	6,929	6,936	6,941	6,946	6,953	6,958	6,962	6,969	83,261
TOTAL JURISDICTIONAL SALES	7,221,012	7,096,194	6,610,681	7,024,985	7,207,881	8,629,437	8,965,860	9,224,663	9,351,388	8,645,843	7,294,109	7,457,259	94,729,311
Resale	73,587	70,890	72,529	77,589	81,987	86,753	126,064	128,697	129,962	127,335	119,843	112,054	1,207,289
TOTAL SALES	7,294,599	7,167,085	6,683,209	7,102,574	7,289,868	8,716,190	9,091,924	9,353,360	9,481,350	8,773,178	7,413,952	7,569,312	95,936,600
CUSTOMERS													
Residential	3,549,316	3,558,228	3,567,094	3,571,699	3,557,724	3,558,842	3,561,433	3,562,609	3,568,566	3,571,609	3,581,749	3,593,959	3,566,986
Commercial	431,945	433,350	433,911	434,906	436,372	434,461	434,937	435,897	437,145	437,896	438,772	440,057	435,804
Industrial	15,275	15,261	15,257	15,254	15,175	15,242	15,239	15,190	15,177	15,144	15,155	15,147	15,210
Street & Highway	2,499	2,504	2,511	2,516	2,521	2,528	2,533	2,537	2,544	2,549	2,553	2,560	2,530
Other	248	248	248	248	248	248	248	248	248	248	248	248	248
Railroads & Railways	23	23	23	23	23	23	23	23	23	23	23	23	23
TOTAL JURISDICTIONAL CUSTOMERS	3,999,307	4,009,613	4,019,043	4,024,646	4,012,063	4,011,345	4,014,413	4,017,504	4,023,704	4,027,470	4,038,499	4,031,994	4,020,800
Resale	3	3	3	3	3	4	4	4	4	4	4	4	4
TOTAL CUSTOMERS	3,999,310	4,009,616	4,019,046	4,024,649	4,012,066	4,011,349	4,014,417	4,017,508	4,023,708	4,027,474	4,038,503	4,031,998	4,020,804
USE PER CUSTOMER													
Residential	1,092	1,057	913	991	1,020	1,339	1,401	1,460	1,468	1,353	1,039	1,048	14,180
Commercial	6,858	6,809	6,835	7,125	7,314	8,007	8,250	8,337	8,526	7,827	7,263	7,506	90,669
Industrial	22,069	22,043	22,290	22,265	22,360	22,228	22,222	22,290	22,280	22,349	22,323	22,325	267,041
Street & Highway	14,134	14,13[illegible]	14,134	14,134	14,134	14,134	14,134	14,134	14,134	14,134	14,134	14,134	169,603
Other	17,594	19,078	18,606	19,719	20,495	22,862	24,005	23,669	24,072	20,258	20,981	20,107	251,446
Railroads & Railways	300,380	300,570	300,871	301,087	301,277	301,580	301,797	301,987	302,288	302,503	302,692	303,009	3,620,041
TOTAL JURISDICTIONAL USE PER CUSTOMER	1,806	1,770	1,645	1,745	1,797	2,151	2,233	2,296	2,324	2,147	1,806	1,840	23,560
Resale	24,529,040	23,630,162	24,176,168	25,863,091	27,329,067	21,688,185	31,515,943	32,174,196	32,490,519	31,833,652	29,960,709	28,013,429	336,917,892
TOTAL USE PER CUSTOMER	1,824	1,787	1,663	1,765	1,817	2,173	2,265	2,328	2,356	2,178	1,836	1,868	23,860

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-16)
Pre- and Post-September 11, 2001 Sales
Estimates for 2002 and 2005

2005 MONTHLY FORECAST OF
BILLED SALES, CUSTOMERS AND USE BY CLASS

	January	February	March	April	May	June	July	August	September	October	November	December	2002 Budget Forecast Total
SYSTEM SALES (mWh)													
Residential	4,534,342	4,412,571	3,825,434	4,013,918	4,074,195	5,333,816	5,589,577	5,835,704	5,883,326	5,491,465	4,284,523	4,342,310	57,621,582
Commercial	3,232,659	3,255,765	3,293,143	3,477,164	3,523,384	3,817,493	3,949,530	3,960,190	4,052,804	3,695,584	3,442,604	3,594,030	43,294,149
Industrial	340,515	340,416	340,691	340,283	340,814	340,743	340,875	340,689	340,958	340,791	340,702	340,646	4,088,123
Street & Highway	37,980	38,027	38,108	38,154	38,200	38,280	38,326	38,371	38,450	38,494	38,538	38,617	459,544
Other	4,333	4,697	4,581	4,854	5,044	5,424	5,904	5,822	5,921	4,986	5,163	4,949	61,879
Railroads & Railways	7,021	7,025	7,032	7,037	7,041	7,048	7,053	7,057	7,064	7,069	7,073	7,080	84,600
TOTAL JURISDICTIONAL SALES	8,156,850	8,058,501	7,508,988	7,881,411	7,989,079	9,543,004	9,931,064	10,187,833	10,328,522	9,578,389	8,118,603	8,327,632	105,609,877
Resale	111,339	109,630	107,973	116,327	120,724	124,392	130,763	133,396	134,662	132,035	124,543	116,754	1,462,534
TOTAL SALES	8,268,189	8,168,131	7,616,962	7,997,738	8,109,804	9,667,396	10,061,827	10,321,229	10,463,183	9,710,424	8,243,146	8,444,386	107,072,411
CUSTOMERS													
Residential	3,749,897	3,758,581	3,767,194	3,767,531	3,760,293	3,761,234	3,763,769	3,765,755	3,770,567	3,773,465	3,783,668	3,795,965	3,768,160
Commercial	467,310	468,043	469,081	470,349	471,606	472,131	472,543	473,185	473,775	474,348	475,454	476,370	472,016
Industrial	15,217	15,219	15,220	15,221	15,219	15,219	15,220	15,220	15,221	15,222	15,224	15,226	15,221
Street & Highway	2,687	2,691	2,696	2,700	2,703	2,708	2,712	2,715	2,720	2,724	2,727	2,732	2,710
Other	248	248	248	248	248	248	248	248	248	248	248	248	248
Railroads & Railways	23	23	23	23	23	23	23	23	23	23	23	23	23
TOTAL JURISDICTIONAL CUSTOMERS	4,235,382	4,244,804	4,254,462	4,256,071	4,250,091	4,251,563	4,254,515	4,257,146	4,262,554	4,166,029	4,277,343	4,290,564	4,258,377
Resale	4	4	4	4	4	4	4	4	4	4	4	4	4
TOTAL CUSTOMERS	4,235,386	4,244,808	4,254,466	4,256,075	4,250,095	4,251,567	4,254,519	4,257,150	4,262,558	4,266,033	4,277,347	4,290,568	4,258,381
USE PER CUSTOMER													
Residential	1,209	1,174	1,015	1,065	1,084	1,418	1,485	1,550	1,560	1,455	1,132	1,144	15,292
Commercial	6,918	6,956	7,020	7,393	7,471	8,086	8,358	8,369	8,554	7,791	7,241	7,545	91,722
Industrial	22,377	22,368	22,384	22,357	22,394	22,389	22,397	22,384	22,401	22,389	22,380	22,372	268,592
Street & Highway	14,134	14,134	14,134	14,134	14,134	14,134	14,134	14,134	14,134	14,134	14,134	14,134	169,603
Other	17,473	18,940	18,473	19,573	20,339	22,678	23,807	23,475	23,873	20,103	20,819	19,956	249,511
Railroads & Railways	305,245	305,448	305,747	305,958	306,142	306,436	306,646	306,831	307,126	307,338	307,524	307,828	3,678,270
TOTAL JURISDICTIONAL USE PER CUSTOMER	1,926	1,898	1,763	1,852	1,880	2,245	2,334	2,393	2,423	2,245	1,898	1,941	24,800
Resale	27,833,772	27,407,472	26,993,332	29,081,770	30,181,124	31,097,882	32,690,757	33,349,069	33,665,451	33,008,653	31,135,746	29,188,501	365,633,530
TOTAL USE PER CUSTOMER	1,952	1,974	1,790	1,879	1,908	2,274	2,365	2,424	2,455	2,276	1,927	1,968	25,144

10/18/01
2002 Alt Forecast

2002 MONTHLY FORECAST OF
BILLED SALES, CUSTOMERS AND USE BY CLASS

	January	February	March	April	May	June	July	August	September	October	November	December	Total	
SYSTEM SALES (mWh)														
Residential	3,879,514	3,697,859	3,150,637	3,361,977	3,563,562	4,532,773	4,748,487	5,085,559	4,947,172	4,651,004	3,808,390	3,648,215	49,065,148	2.6%
Commercial	2,965,998	2,900,408	2,867,874	2,943,376	3,134,013	3,302,815	3,414,330	3,551,603	3,520,758	3,298,799	3,261,967	3,197,757	38,339,698	1.8%
Industrial	337,510	330,675	328,870	322,620	333,182	321,671	322,238	330,904	319,415	325,775	346,264	327,395	3,946,519	-3.7%
Street & Highway	35,361	34,786	34,324	33,781	34,987	33,926	34,064	35,051	33,970	34,674	36,938	35,031	416,892	-0.6%
Other	4,369	4,651	4,462	4,645	4,991	5,383	5,665	5,737	5,639	4,836	5,326	4,828	60,531	-10.1%
Railroads & Railways	6,917	6,795	6,692	6,578	6,804	6,586	6,605	6,788	6,568	6,697	7,126	6,747	80,903	-3.2%
TOTAL JURISDICTIONAL SALES	7,229,668	6,973,174	6,392,860	6,672,978	7,077,538	8,193,153	8,531,388	9,015,641	8,833,522	8,321,786	7,466,011	7,219,973	91,929,691	2.0%
Resale	73,587	70,890	72,529	77,589	81,987	86,753	126,064	128,697	179,962	127,335	119,843	112,054	1,207,289	21.9%
TOTAL SALES	7,303,255	7,046,064	6,465,388	6,750,567	7,159,525	8,279,906	8,657,451	9,144,338	8,963,484	8,449,120	7,585,854	7,332,027	93,136,980	2.2%
CUSTOMERS														
Residential	3,530,945	3,539,811	3,548,631	3,553,212	3,539,310	3,540,422	3,542,999	3,545,164	3,550,095	3,553,123	3,563,210	3,575,357	3,548,523	1.7%
Commercial	429,710	431,107	431,665	432,635	434,113	432,213	432,686	433,641	434,883	435,610	436,501	437,779	433,548	1.8%
Industrial	15,196	15,182	15,178	15,175	15,096	15,163	15,160	15,111	15,099	15,066	15,076	15,069	15,131	-2.1%
Street & Highway	2,499	2,504	2,511	2,516	2,521	2,528	2,533	2,537	2,544	2,549	2,553	2,560	2,530	3.3%
Others	248	248	248	248	248	248	248	248	248	248	248	248	248	-0.9%
Railroads & Railways	23	23	23	23	23	23	23	23	23	23	23	23	23	0.0%
TOTAL JURISDICTIONAL CUSTOMERS	3,978,621	3,988,875	3,998,256	4,003,830	3,991,311	3,990,597	3,993,649	3,996,724	4,002,892	4,006,639	4,017,611	4,031,036	4,000,003	1.7%
Resale	3	3	3	3	3	4	4	4	4	4	4	4	4	19.4%
TOTAL CUSTOMERS	3,978,624	3,988,878	3,998,259	4,003,833	3,991,314	3,990,601	3,993,653	3,996,728	4,002,896	4,006,643	4,017,615	4,031,040	4,000,007	1.7%
USE PER CUSTOMER														
Residential	1,099	1,045	888	946	1,007	1,277	1,340	1,435	1,394	1,309	1,069	1,020	13,827	0.7%
Commercial	6,902	6,728	6,644	6,803	7,219	7,642	7,891	8,190	8,096	7,572	7,473	7,304	88,478	0.0%
Industrial	22,210	21,780	21,668	21,259	22,070	21,214	21,255	21,898	21,155	21,623	22,967	21,727	260,823	1.3%
Street & Highway	14,151	13,893	13,668	13,425	13,878	13,419	13,449	13,813	13,351	13,604	14,467	13,684	164,799	-1.0%
Other	17,615	18,753	17,993	18,731	20,125	21,706	22,841	23,132	22,739	19,499	21,475	19,467	244,076	-6.6%
Railroads & Railways	300,740	295,444	290,957	286,000	295,829	286,332	287,172	295,145	285,548	291,165	309,825	293,368	3,517,525	-0.4%
TOTAL JURISDICTIONAL USE PER CUSTOMER	1,817	1,749	1,599	1,667	1,773	2,053	2,136	2,256	2,207	2,077	1,858	1,791	22,982	0.3%
Resale	24,529,040	23,630,162	24,176,168	25,863,091	27,329,067	21,688,185	31,515,943	32,174,196	32,490,519	31,833,652	29,960,709	28,013,429	336,917,892	2.1%
TOTAL USE PER CUSTOMER	1,836	1,766	1,617	1,686	1,794	2,075	2,168	2,288	2,239	2,109	1,888	1,819	23,284	0.5%

Docket No. 001148-EI
L. Kollen Exhibit No. ___ (LK-16)
Pre- and Post-September 11, 2001 Sales Estimates for 2002 and 2005
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00100652

10/18/01
2002 Alt Forecast

2005 MONTHLY FORECAST OF
BILLED SALES, CUSTOMERS AND USE BY CLASS

	January	February	March	April	May	June	July	August	September	October	November	December	Total	
SYSTEM SALES (mWh)														
Residential	4,496,653	4,309,366	3,675,427	3,807,797	4,016,477	5,082,099	5,337,761	5,718,379	5,563,487	5,291,009	4,391,785	4,211,306	55,901,544	4.3%
Commercial	3,205,789	3,179,616	3,164,009	3,298,606	3,473,127	3,637,335	3,771,409	3,880,571	3,812,479	3,560,684	3,528,789	3,485,600	42,018,013	2.7%
Industrial	337,685	332,454	327,331	322,809	335,953	324,662	325,518	333,840	322,422	328,351	349,231	330,369	3,970,626	0.0%
Street & Highway	37,664	37,137	36,613	36,195	37,656	36,474	36,599	37,599	36,359	37,089	39,505	37,452	446,340	2.0%
Other	4,297	4,587	4,402	4,605	4,972	5,359	5,638	5,705	5,599	4,804	5,292	4,800	60,060	-0.3%
Railroads & Railways	6,962	6,861	6,756	6,676	6,941	6,715	6,735	6,915	6,680	6,811	7,350	6,866	82,169	0.5%
TOTAL JURISDICTIONAL SALES	8,089,051	7,870,021	7,214,538	7,476,688	7,875,125	9,092,643	9,483,661	9,983,009	9,767,026	9,228,747	8,321,851	8,076,393	102,478,753	3.5%
Resale	111,335	109,630	107,973	116,327	120,724	124,392	130,763	133,396	134,662	132,035	124,545	116,754	1,462,534	1.2%
TOTAL SALES	8,200,386	7,979,651	7,322,511	7,593,015	7,995,850	9,217,035	9,614,424	10,116,406	9,901,687	9,360,782	8,446,394	8,193,147	103,941,287	3.4%
CUSTOMERS														
Residential	3,717,464	3,726,073	3,734,611	3,734,946	3,727,770	3,728,703	3,731,216	3,733,181	3,737,955	3,740,828	3,750,942	3,763,133	3,735,569	1.7%
Commercial	463,268	463,995	465,024	466,281	467,527	468,047	468,456	469,092	469,677	470,245	471,341	472,250	467,934	2.6%
Industrial	15,085	15,087	15,089	15,089	15,087	15,088	15,088	15,088	15,089	15,090	15,092	15,094	15,089	-0.3%
Street & Highway	2,687	2,691	2,696	2,700	2,703	2,708	2,712	2,715	2,720	2,724	2,727	2,732	2,710	2.0%
Other	248	248	248	248	248	248	248	248	248	248	248	248	248	0.0%
Railroads & Railways	23	23	23	23	23	23	23	23	23	23	23	23	23	0.0%
TOTAL JURISDICTIONAL CUSTOMERS	4,198,776	4,208,116	4,217,691	4,219,286	4,213,358	4,214,817	4,217,743	4,220,352	4,225,713	4,229,158	4,240,374	4,253,481	4,221,572	1.8%
Resale	4	4	4	4	4	4	4	4	4	4	4	4	4	0.0%
TOTAL CUSTOMERS	4,198,780	4,208,120	4,217,695	4,219,290	4,213,362	4,214,821	4,217,747	4,220,356	4,225,717	4,229,162	4,240,378	4,253,485	4,221,576	1.8%
USE PER CUSTOMER														
Residential	1,210	1,157	984	1,020	1,077	1,363	1,431	1,532	1,488	1,414	1,171	1,119	14,965	2.6%
Commercial	6,920	6,853	6,804	7,074	7,429	7,771	8,051	8,273	8,160	7,572	7,487	7,381	89,795	0.2%
Industrial	22,385	22,036	21,694	21,394	22,267	21,519	21,575	22,126	21,368	21,760	23,140	21,887	263,148	0.3%
Street & Highway	14,016	13,803	13,579	13,408	13,932	13,467	13,497	13,849	13,365	13,618	14,487	13,707	164,730	0.0%
Other	17,328	18,497	17,749	18,568	20,049	21,608	22,734	23,003	22,575	19,371	21,340	19,354	242,176	-0.3%
Railroads & Railways	302,708	298,304	293,758	290,247	301,776	291,974	292,832	300,662	290,429	296,119	315,223	298,541	3,572,572	0.5%
TOTAL JURISDICTIONAL USE PER CUSTOMER	1,927	1,870	1,711	1,772	1,869	2,157	2,249	2,365	2,311	2,182	1,963	1,899	24,275	1.7%
Resale	27,833,772	27,407,472	26,993,332	29,081,770	30,181,124	31,097,882	32,690,757	33,349,069	33,665,451	33,008,653	31,135,746	29,188,501	365,633,530	1.2%
TOTAL USE PER CUSTOMER	1,953	1,896	1,736	1,800	1,898	2,187	2,280	2,397	2,343	2,213	1,992	1,926	24,621	1.6%

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L. Kollen Exhibit No. ___ (LK-16)
Pre- and Post-September 11, 2001 Sales
Estimates for 2002 and 2005
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00100655

Florida Power & Light Company
Docket No. 001148-EI
OPC Third Request For Production of Documents
Request No. 89
Page 1 of 1

Q.

Please provide the agreement(s) between FPL and FPL FiberNet for the sale and purchase of FPL's fiber optic assets.

A.

There is no written agreement of purchase and sale for the transfer of the assets in question. The assets were transferred on the basis of two independent appraisals and pursuant to a release from the utility's mortgage and deed of trust.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	**CASE NO. 2011-00161**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	**CASE NO. 2011-00162**

RESPONSE OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
TO KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY'S
DATA REQUESTS

21. Please refer to Appendix A to Mr. Hill's testimony and provide a detailed list of each and every regulatory proceeding in which he has testified including the jurisdiction, case or docket number, style or name of the case, regulated company, party represented, regulatory authority, date of the testimony and a brief description of the topics in the testimony.

RESPONSE:

Please see "HillCaseList.doc" attached and included in electronic format on attached CD.

STEPHEN G. HILL
EXPERT TESTIMONY

WEST VIRGINIA

Testimony on behalf of : Consumer Advocate Division of the WV Public Service Commission

Case No. 80-039-G-42T - Holden Division, Southern Public Service Company; cost of capital / capital structure

Case No. 80-040-G-42T - Logan Division, Southern Public Service Company; cost of capital / capital structure

Case No. 80-041-G-42T - Man Division, Southern Public Service Company; cost of capital / capital structure

Case No. 82-207-W-42T - Huntington Water Corporation; cost of capital / capital structure

Case No. 82-162-E-42T - Appalachian Power Company; cost of capital / capital structure

Case No. 82-334-E-42T - Wheeling Electric Company; cost of capital / capital structure

Case No. 82-380-G-42T - Columbia Gas of West Virginia; cost of capital / capital structure / equity cost penalty

Case No. 82-391-E-42T - Virginia Electric Power Company; cost of capital / capital structure

Case No. 82-580-E-GI - Potomac Edision Electric Company;"show cause" hearing; cost of capital / capital structure

Case No. 82-561-W-42T - West Virginia Water Company; cost of capital / capital structure

Case No. 82-615-G-42T - Equitable Gas Company; cost of capital / capital structure

Case No. 83-030-E-GI - Appalachian Power Company (fuel review) ; engineering issues / line loss

Case No. 83-170-W-42T - Huntington Water Corporation; cost of capital / capital structure / double leverage

Case No. 83-316-G-42T - Milton Division, Southern Public Service Company; cost of capital / capital structure

Case No. 83-317-G-42T - Holden Division, Southern Public Service Company; cost of capital / capital structure

Case No. 83-318-G-42T - Montgomery Division, Southern Public Service Company; cost of capital / capital structure

Case No. 83-319-G-42T - Logan Division, Southern Public Service Company; cost of capital / capital structure

Case No. 83-320-G-42T - Boone Division, Southern Public Service Company; cost of capital / capital structure

Case No. 83-321-G-42T - Man Division, Southern Public Service Company; cost of capital / capital structure

Case No. 83-383-E-GI - Appalacian Power Company (fuel review); engineering issues / line loss

Case No. 83-333-G-42T - Penzoil Company; cost of capital / capital structure

Case No. 83-411-E-42T - Virginia Electric and Power Company; cost of capital / capital structure

Case No. 83-648-G-SC - Columbia Gas of West Virginia / Allegheny and Western Energy Corporation (special hearing to investigate a buy-out of Columbia by A&W); financial integrity of purchasingcompany / potential ratepayer impact

Case No. 83-692-E-42T - Appalachian Power Company; cost of capital / capital structure

Case No. 84-008-W-42T - West Virginia Water Company; cost of capital / capital structure / double leverage

Case No. 84-191-E-42T - Wheeling Electric Company; cost of capital / capital structure

Case No. 84-173-W-42T - Huntington Water Corporation; cost of capital / capital structure / double leverage

Case No. 84-250-T-42T - West Virginia Telephone Company; cost of capital / capital structure / double leverage

Case No. 84-168-E-42T - Monongahela Power Company; cost of capital / capital structure

Case No. 84-7338-G-42T - Hope Gas, Incorporated; cost of capital / capital structure

Case No. 84-875-E-42T - Potomac Edison Electric Company; cost of capital / capital structure

Case No. 84-747-T-42T - Chesapeake and Potomac Telephone Company of West Virginia; cost of capital / capital structure

Case No. 84-861-G-42T - Consumer's Gas Company; cost of capital capital structure

Case No. 85-179-W-42T - Huntington Water Corporation; cost of capital / capital structure / double leverage

Case No. 85-289-G-42T - Penzoil Company; cost of capital / capital structure

Case No. 85-204-W-42T - West Virginia Water Company; cost of capital / capital structure / double leverage

Case No. 85-222-T-42T - Continental Telephone Company of West Virginia; cost of capital / capital structure / double leverage

Case No. 85-405-G-30C - Mountaineer Gas Company; investor attitudes toward company's gas supplier and owner-Allegheny and Western Energy / affiliated transactions

Case No. 85-553-E-PC - Utilicorp United, Inc.; incremental cost of capital charges borne by ratepayers due to buy-out of Virginia Electric and Power's West Virginia service territory by Company

Case No. 85-536-E-42T - Virginia Electric and Power Company; cost of capital / capital structure

Case No. 86-008-G-42T - Southern Public Service Company; cost of capital / capital structure

Case No. 86-524-E-SC - Monongahela Power Company ("show cause" proceeding); cost of capital / capital structure

Case No. 86-212-W-42T - West Virginia Water Company; cost of capital / capital structure

Case No. 86-341-W-42T - Huntington Water Corporation; cost of capital / capital structure

Case No. 86-587-E-42T - Wheeling Electric Company; cost of capital / capital structure

Case No. 86-604-G-42T - Mountaineer Gas Company; cost of capital / hypothetical capital structure / management efficiency / equity return penalty

Case No. 86-780-T-42T - General Telephone Company of the South; cost of capital / capital structure / rural telephone company operating risk

Case No. 88-097-G-42T - Consumer's Gas Company; cost of capital hypothetical capital structure

Case No. 88-685-T-42T - General Telephone Company of the South; cost of capital / capital structure / earnings stability

Case No. 88-311-G-PC - Hope Gas, Inc.; financial condition of Company

Case Nos. 89-439 and 87-434-G-30C - Hope Gas, Inc.; ability of Company to refund purchased gas overcollections

Case No. 89-206-T-42T - Contel of West Virginia; cost of capital / capital structure

Case No. 89-481-G-42T - Equitable Gas Company; cost of capital / capital structure

Case No. 89-498-W-42T - West Virginia-American Water Co.;cost of capital / capital structure

Case No. 89-640-G-42T - Mountaineer Gas Company; cost of capital / capital structure

Case No. 90-243-E-42T - Wheeling Electric Power Company; cost of capital / capital structure

Case No. 90-522-T-42T - GTE South; Telephone utility operating risk / ratemaking capital structure / cost of capital

Case No. 90-504 -E-42T - Monongahela Power Company; capital structure, cost of capital, flotation cost issues

Case No. 90-888-G-42T - Equitable Gas Company; capital structure, cost of equity, inflation adjustment

Case No. 91-025 -G-42T - Hope Gas, Inc.; capital structure, earnings volatility analysis, cost of capital, flotation cost issues

Case No. UT-09-0871 – Frontier Communications/Verizon merger; Financial Issues related to merger.

<u>ARIZONA</u>

Testimony on behalf of : Az. Corporation Commission, Residential Utiltiy Consumer Office

Docket No. U-1933-88-280 - Tucson Electric Power Company; cost of capital / capital structure / unregulated subsidiary risk

Docket No. U-1551-89-102 - Southwest Gas Corporation; cost of capital / actual v. hypothetical capital structure / use of jurisdictional capital structures

Docket No. U-1345--90-007 - Arizona Public Service Company; cost of capital / capital structure / electric utility dividend policy / recommended dividend policy for APS / electric utility industry diversification

Docket No. U-1551-90-322 - Southwest Gas Corporation; cost of capital / actual v. hypothetical capital structure / use of jurisdictional capital structures

Docket No. U-5555-91-333 - US West, Inc. - capital structure / cross-subsidization of unregulated by regulated operations / operating risk analysis / cost of equity capital [case settled after filing of testimony]

Docket No. U-1933-92-101 - Tucson Electric Power; engaged by Commission Advisory Staff to review and analyze Company filing and intervenor testimony in TEP financial reorganization case

Docket No. E-1032-93-073- Citizens Utilities - Arizona Electric Division ; cost of capital / capital structure

Docket No. E-1032-92-183 - Citizens Utilities - Agua Fria Water Company; cost of capital / capital structure

Docket No. E-1032-93-203 - Citizens Utilities - Northern Arizona Gas Division; cost of capital / capital structure

Docket No. E1032-93-183 - US WEST Communications - Arizona ; cost of capital / operating risk / capital structure

Docket No. U-1551-93-272- Southwest Gas Corporation; cost of capital / capital structure

Docket Nos. U-1933-95-069 and -317 - Tucson Electric Power; holding company restructuring, cost of capital, capital strucutre, settlement issues

Docket Nos. E-1032-95-417, et. al. - Citizens Utilities Maricopa Water/Wastewater Division; cost of capital / capital structure / leverage-risk adjustment

Docket No. E-1032-95-433 - Citizens Utilities Arizona electric Division; cost of capital / capital structure / leverage-risk adjustment

Docket No. E-1032-95-473 - Citizens Utilities Northern Arizona Gas Division; cost of capital / capital structure / leverage-risk adjustment

Docket No. U-1551-96-596 – Southwest Gas Corporation – cost of equity capital / capital structure

Docket No. T-01051B-99-105 - US WEST Communications - Arizona ; cost of capital / operating risk / capital structure

Docket No. G-01551A-00-0309 – Southwest Gas Corporation – cost of equity capital / capital structure / debt refinancing

Docket No. E-01245A-03-04437 – Arizona Public Service Company – capital structure / cost of common equity / restructuring issues

Docket No. G-01551A-04-0876 – Southwest Gas Corporation – cost of equity capital / capital structure / recapitalization plan

Docket No. E-01345A-05-0816 – Arizona Public Service Company – capital structure / cost of common equity / restructuring issues

Docket No. G-01551A-04-0876 – Southwest Gas Corporation – cost of equity capital / capital structure / recapitalization plan

Docket No. E-01345A-05-0816 – Arizona Public Service Company – capital structure / cost of common equity / restructuring issues

CALIFORNIA

Testimony on behalf of : Utility Consumers Action Network (UCAN) and Toward Utility Rate Normalization (TURN) (1992), Federal Executive Agencies (2007)

Application Nos. 92-05-010 through 015 - Annual Cost of Capital Proceeding; cost of equity capital

Application Nos. 07-05-003 through 008 - Annual Cost of Capital Proceeding; cost of equity capital

CONNECTICUT

Testimony on behalf of the Office of Consumer Counsel

Docket No. 01-05-19PH01 – Yankee Gas Services Company – capital structure / short-term debt / cost of equity capital

Docket No. 10-02-13 – Aquarion Water Company – capital structure/ corporate structure/cost of equity capital

DISTRICT OF COLUMBIA

Testimony on behalf of : DC Peoples' Counsel

Formal Case No. 916 - Washington Gas Light - review the application to issue securities / projected financial statements / recommended alternative financing plan

GEORGIA

Testimony on behalf of the Governor's Office of Consumer Utility Counsel

Docket No, 14000-U – Georgia Power Company – Testimony on capital structure and the cost of equity capital / comparable earnings

Docket No, 14618-U – Savannah Electric & Power Company – Testimony on capital structure and the cost of equity capital / comparable earnings

Docket No, 18300-U – Georgia Power Company – Testimony on capital structure and the cost of equity capital / investor required market return

Docket No. 18638-U – Atlanta Gas Light – Testimony on capital structure and the cost of equity capital

Docket No. 19758-U – Savannah Electric and Power Company – Testimony on capital structure and the cost of common equity

Docket No. 20298-U – Atmos Energy – Testimony on cost of common equity and capital structure

HAWAII

Testimony on behalf of Department of Commerce; the County of Kauai, Department of Defense

Docket No. 7585 - GTE Hawaiian Telephone - Testimony addressed the financial and cost of capital impacts of a surcharge designed to recover weather-related damages.

Docket No. 7579 - GTE Hawaiian Telephone - capital structure/ operating risk / cost of equtiy

Docket No. 94-0097 - Citizens Utilities Kauai Electric Division - risk/return requirements within a regulatory framework regarding natural disasters

Docket No. 94-0298 - GTE Hawaiian Telephone - capital structure / cost of equity capital / weather-related damage risk

Docket No. 95-0051 - Proceeding to Examine the Establishment of a Self-Insured property Damage Reserve for Public Utilities in the State of Hawaii - risk/return requirements within a regulatory framework regarding natural disasters

Docket No. 04-0104 – Purchase of Verizon Hawaii by the Carlyle Group; developed position on financial requirements for Consumer Advocate

Docket No. 04-0113 – Hawaiian Electric Company, Testimony on cost of equity capital and capital structure.

Docket No. 06-0386 – Hawaiian Electric Company, Testimony on cost of equity capital and capital structure.

Docket No. 10-0083 – Hawaiian Electric Company, Testimony on cost of equity capital and capital structure, cost of capital impact of decouplin

ILLINOIS

Testimony on behalf of : the City of Chicago and the Illinois Attorney General

Docket No. 91-0586 - The Peoples Gas Light and Coke Company; capital structure / projected capital structure / cost o f equity capital / focus on analysts' projected growth rates

Docket No. 92-0448 - Illinois Bell Telephone Company - Alternative Regulation case, testimony on capital structure / cost of capital

Docket No. 95-0032 - The Peoples Gas Light and Coke Company; capital structure / projected capital structure / cost o f equity capital

Docket No. 95-0031 - North Shore Gas; capital structure / projected capital structure / cost o f equity capital

INDIANA

Testimony on behalf of : Ofice of Utiltiy Consumer Counselor

Cause No. 38880 - Indiana-American Water Company; cost of capital / capital structure

Cause No. 39641 - Indiana Cities Water Corporation; cost of capital / fair value rate base

KANSAS

Testimony on behalf of the Citizen's Utilities Ratepayer Board

Docket No. 186,371-U 93-GIME-391-GIE - Commission investogation of § 712 Standards of the Energy Policy Act of 1992, comments on purchased power agreements.

Docket No. 01-WSRE-436-RTS – Western Resources – capital structure / cost of equity / capital structure implications of spin-off of unregulated operations

Docket No. WSRE-949-GIE – Western Resources – review of company plans to separate electric utility business from unregulated business

Docket No. 03-KGSC-602-RTS – Kansas Gas Service Company – capital structure / convertible preferred stock / cost of common equity / overall cost of capital

KENTUCKY

Testimony on behalf of the Office of Attorney General, and Kentucky Industrial Utility Customers

Case No. 2008-00427 – Kentucky-American Water Company – capital structure / cost of equity / use of book value capital structures

Case Nos. 2020-00161, 162 – Kentucky Utilities Company and Louisville Gas & Electric Company – capital structure / cost of equity / impact of environmental surcharge regulation

LOUISIANA

Testimony on behalf of : Louisiana Public Service Commission Staff

Docket No. U-20925 – Entergy Louisiana, Inc. – Annual Rate Review/ Formula Rate Plan / FRP 2000 and FRP 2001 – Testimony on the cost of common equity capital

MAINE

Testimony on behalf of : Public Advocate

Docket No. 84-104 - Continental Telephone Company of Maine; cost of capital / capital structure / double leverage

Docket No. 85-159 - New England Telephone and Telegraph Co.; case settled; prepared settlement position for Public Advocate

Docket No. 86-242 - Bangor Hydro-Electric Company; cost of capital / capital structure / relative risk / recapitalization options

Docket No. 89-68 - Central Maine Power; cost of capital / capital structure / flotation and market pressure cost issues

Docket No. 89-354 - Maine Water Company; cost of capital / capital structure

Docket No. 90-001 - Bangor Hydro-Electric Company; cost of capital / capital structure

Docket No. 90-076 - Central Maine Power; cost of capital / capital structure / flotation and market pressure cost issues

Docket No. 90-085- Central Maine Power Company; decoupling risk/cost of capital

Docket No. 93-005 and 93-145 - Consumers Maine Water Company; cost of capital impacts of merger, cost of equity, capital structure (testimony on behalf of municipal and industrial intervenors as well as Maine Consumer Advocate)

Docket No. 97-016 – Central Maine Power – Mid-period Review of Alternative Rate Plan, cost of capital, capital structure issues.

Docket No. 97-580 – Central Maine Power – Stranded Cost Review/Transmission & Distribution Rate Case, cost of capital, capital structure, relative risk of distribution operations

Special Project for Maine Public Advocate – Gas distribution cost of capital, merger risk.

Docket No. 2001-249 – Community Service Telephone Company – capital structure / company financial history / cost of equity

Docket Nos. 2002-99/2002-100 – Lincolnville/Tidewater Telecom – capital structure / cost of common equity capital

Docket Nos.2002-747, 2003-34, 35, 36, and 37 – FairPoint New England Telephone Companies; testimony on capital structure, cost of common equity.

Docket No. 2004-112 – Bangor Hydro-Electric Company; testimony on capital structure; market-based cost of common equity, overall cost of capital

Docket No. 112/339 – Bangor Hydro-Electric Company; Central Maine Power; stranded cost hearings, lower risk of guaranteed returns, cost of common equity capital for electrics

Docket No. 2005-155 –Verizon Maine – Alternative Form of Regulation/Rate Proceeding; cost of equity capital for a local distribution company and capital structure / competition

Docket No. 2007-215 - Central Maine Power; cost of capital / capital structure / market risk premium issues

MARYLAND

Testimony on behalf of : Maryland Peoples' Counsel

Case No. 8119 - Maryland Natural Gas Company; cost of capital / capital structure (current and pro-forma)

Case No. 8191 - Maryland Natural Gas Company; cost of capital / capital structure (current and hypothetical) / earnings stability

Case No. 8469 - PotomacEdison Company; capital structure, cost of capital, flotation cost issues, purchased power issues

Case No. 8725 - Baltimore Gas & Electric Company and Potomac Electric Company merger application - cost of capital / capital structure for individual and combined companies

Case No. 8774 – Potomac Edison (Allegheny Energy) – cost of equity, capital structure, merger issues (APS-DQE)

Case No. 8794/8804 – Baltimore Gas & Electric Company – Electric Restructuring, cost of equity capital for integrated electrics, T&D, merchant power plants, capital structure and regulatory policy issues.

Case No. 8795 – Delmarva Power & Light Company (Connectiv) – Electric Restructuring, cost of equity capital for integrated electrics, T&D, merchant power plants, capital structure and regulatory policy issues.

Case No. 8796 – Potomac Electric Power Company– Electric Restructuring, cost of equity capital for integrated electrics, T&D, merchant power plants, capital structure and regulatory policy issues.

Case No. 8797 –Potomac Edison Company (Allegheny Energy) – Electric Restructuring, cost of equity capital for integrated electrics, T&D, merchant power plants, capital structure and regulatory policy issues.

Case No. 8819 - Washington Gas Light Company – Alternative Regulatory proposal, cost of capital, capital structure, regulatory policy issues.

Case No. 8829 – Baltimore Gas and Electric Company / Gas Division – cost of capital, capital structure

Case No. 8890 – Pepco/Delmarva Merger – financial and capital structure issues related to the proposed merger

Case No. 8883 – Baltimore Gas & Electric Company – business separation of Constellation Energy – financial and capital structure issues related to the proposed business separation

Case No. 8920 – Washington Gas Light Company – Capital structure, cost of capital

Case No. 8959 - Washington Gas Light Company – Capital structure, cost of capital

Case No. 8994 – Delmarva Power & Light – Capital structure, financial cross-subsidization, cost of capital benchmark for merger review.

Case No. 8995 – Potomac Electric Power Company – Capital structure, financial cross-subsidization, cost of capital benchmark for merger review.

MASSACHUSETTS

Testimony on behalf of: Attorney General of Massachusetts

Docket No. 09-30 – Bay State Gas Company - Cost of equity/ Financial market conditions/ Decoupling Impact on Cost of Equity Capital

MINNESOTA

Testimony on behalf of: Minnesota Department of Public Service

Docket Nos. P-442, 5321, 3167, 466, 421/CI-96-1540 – US WEST Communications - Unbundled network elements cost proceeding – cost of equity/ capital structure

Docket Nos. P404 et. Al./CI-oo-712 – Sherburne County Rural Telephone Company - Cost of equity/ capital structure/ relative competitive risk of rural telephone companies

MISSOURI

Testimony on Behalf of Office of Public Counsel / Missouri Public Service Commission, Trigen Kansas City (Veolia Energy Kansas City)

Docket No. TC-93-244, et al., Southwestern Bell Telephone Company; capital structure / optimal capital structure / cost o f equity capital

Docket No. WR-95-145, St. Louis County Water Company, capital structure, cost of capital

Testimony on Behalf of Missouri Public Service Commission

Docket No. ER-97-394 – Missouri Public Service (UtiliCorp), cost of capital, capital structure (divisional cost of capital issues)

Docket No. EM-97-515 – Western Resources/Kansas City Power & Light Merger, merger history, financial aspects and impacts of merger, analysis of company testimony, review of alternative regulation proposal

Docket No. ER-2007-0002 and 0003 – Ameren-UE, cost of capital, capital structure, market value versus book value capital structure

Docket No. HR-2008-0300 – Trigen-Kansas City Energy Corporation – capital structure, cost of equity capital, overall cost of capital

Docket No. ER-2008-0318– Ameren-UE, cost of capital, capital structure, overall cost of capital

Docket No. ER-2010-0036—AmerenUE; Cost of equity capital

File No. HR-2011-0241 – Veolia Energy Kansas City, Inc. – capital structure, cost of equity capital, overall cost of capital

MONTANA

Testimony on Behalf of the Montana Consumer Counsel

Docket No. D95.7.90, Montana-Dakota Utilities Company; capital structure / embedded cost of debt refinancing costs / cost o f equity capital

Docket No. D95.9.128, Montana Power Company, capital structure, cost of capital

Docket No. D96.7.123, Great Falls Gas Company, capital structure, cost of capital, relative risk

Docket No. D998.176 – Montana Power Company, Gas Utility Division cost of capital, capital structure

Docket No. D2000.8.113 – Montana Power Company, capital structure, debt refinancing due to sale of generation plants / cost of capital

Docket No. D2000.7.112 – Mountain Water Company / capital structure / cost of equity capital

Docket No. D2002.5.59 – Montana-Dakota Utilities Company, cost of equity / capital structure / overall cost of capital.

Docket No. D2004.4.50– Montana-Dakota Utilities Company, gas operations, cost of equity / capital structure / overall cost of capital.

NEW MEXICO

Testimony on behalf of the State Corporation Commission Staff

Docket No. 92-291-TC, GTE Southwest, capital structure/ operating risk/ cost of equity capital / competitive risk

Case No. 3008 US WEST Communications (before the State Public Regulation Commission), capital structure/ operating risk/ cost of equity capital / competitive risk

NEW HAMPSHIRE

Testimony on behalf of the Office of Consumer Advocate

Docket No. DT02-110, Verizon New Hampshire; cost of common equity and capital structure in both a TELRIC and traditional rate base rate of return cases.

Docket No. DE 04-177; Public Service Company of New Hampshire; cost of equity capital of integrated generation operations.

Docket No. DE-06-028; Public Service Company of New Hampshiore, cost of equity capital, capital structure.

NORTH CAROLINA

Testimony on behalf of the North Carolina Department of Insurance

Docket No. 942 – Private Passenger Automobile Insurance Rate Proceeding – cost of capital/fair rate of return

Docket No. 1073 – Private Passenger Automobile Insurance Rate Proceeding – cost of capital/fair rate of return

Docket No. 1174 – Private Passenger Automobile Insurance Rate Proceeding – cost of capital/fair rate of return

Docket No. 1235 – Private Passenger Automobile Insurance Rate Proceeding – cost of capital/fair rate of return

Docket No. 1407 – Private Passenger Automobile Insurance Rate Proceeding – cost of capital/fair rate of return

OHIO

Testimony on behalf of : Consumers' Counsel

Case No. 85-1778-EL-AIR - Monongahela Power Company; cost of capital / capital structure

Case No. 87-1307-TP-AIR - General Telephone Company of Ohio; cost of capital / capital structure (actual and hypothetical) / earning stability / critical analysis of Commission's "standard adjustment" for flotation-market pressure-financial flexibility

Case No. 88-718-GA-AIR - Columbia Gas of Ohio; cost of capital / capital structure / issuance expense adjustment

OKLAHOMA

Testimony on behalf of the Oklahoma Corporation Commission; Attorney General of Oklahoma

Cause No. PUD 001190 - Oklahoma Natural Gas Company - cost of capital/ capital structure

Cause No. PUD 920001342 - Public Service Company of Oklahoma - cost of capital / capital structure

Cause No. PUD 940000477 - Oklahoma Natural Gas Company - cost of capital/ capital structure

Cause No. PUD 990000166 – Oklahoma Natural Gas Company – cost of capital/ capital structure

Cause No. 200300076 – Public Service Company of Oklahoma – cost of capital/ capital structure/ leverage adjustment to cost of capital

PENNSYLVANIA

Testimony on behalf of : Office of Public Advocate

Docket No. R-870719 - National Fuel Gas Distribution Corporation; cost of capital / capital structure / relative risk

Docket No. R-891259 - Dauphin Consolidated Water Company; cost of capital / ratemaking capital structure / earnings variability

Docket No. R-901609 - West Penn Power Company; capital structure, cost of capital, validity of the DCF model

Docket No. R-912060- Shenango Valley Water Company; cost of capital / capital structure / risk premium volatility

Docket No. R-922180 - Peoples Natural Gas Company; cost of capital / capital structure / business risk of utility operations

Docket No. R-922420- Shenango Valley Water Company; cost of capital / capital structure

Docket No. R-922378- West Penn Power Company; cost of capital / capital structure / risk premium reliability / purchased power risk

Docket No. R-00932798- Shenango Valley Water Company; cost of capital / capital structure

Docket No. R-009438001- Columbia Gas of Pennsylvania ; cost of capital / capital structure / business risk of utility operations

Docket No. R-00943252 - Peoples Natural Gas Company; cost of capital / capital structure

Docket No. R-00953524 - PFG Gas, North Penn Gas; cost of capital / capital structure / use of preferred stock in ratemaking capitalization

Docket No. R-00963858 – Equitable Gas; cost of capital / capital structure

Docket No. R-00984280 – PG Energy, Inc., cost of capital / capital structure

Docket No. R-00005119 – PG Energy, Inc., cost of capital / capital structure

Docket No. R-00005277 – PFG/North Penn Gas Company., cost of capital / capital structure

Docket No. R-00005459 – TW Phillips Oil & Gas Company, cost of capital / capital structure

Docket No. R-00027975 – York Water Company, cost of capital / capital structure

Docket No. R-00038805 – Aqua Pennsylvania Water Company, cost of capital/ capital structure

Docket No. R-00049884 - Pike County Light & Power Company; cost of capital/ capital structure

Docket No. R-00051030 – Aqua Pennsylvania Water Company, cost of capital/ capital structure / market-value capital structures

Docket No. R-00061346 – Duquesne Light Company, cost of capital/ capital structure/ market-value capital structure

Docket No. R-2010-2161694 – PPL Electric Utilities Corporation – cost of capital/capital structure

Docket No. R-2010-2179522 – Duquesne Light Company – cost of capital / capital structure / overall cost of capital

RHODE ISLAND

Testimony on behalf of: Rhode Island Division of Public Utilities

Docket No. 2681 – Bell Atlantic – Rhode Island - Bell Atlantic's Total Elemental Long Run Incremental Cost (TELRIC) Studies for Unbundled Network Elements Filed by the Company Pursuant to Sections 251 and 252 of the Telecommunications Act of 1996 – capital structure / cost of equity capital

SOUTH CAROLINA

Testimony on behalf of : Division of Consumer Advocacy

Docket No. 91-141-G - Piedmont Natural Gas Company; cost of capital / capital structure / use of short-term debt as permanent capital / operating risk analysis

TEXAS

Testimony on behalf of : Texas Attorney General, Austin Ratepayers Association, Office of Public Insurance Counsel, Office of Public Utility Counsel, Allied Coalition of Cities,

Docket No. 5220 - Southwest Bell Telephone Company; cost of capital / capital structure / double leverage

Docket No. 1 - City of Austin Electric Utility; cost of capital / debt service coverage ratio / municipal bond rating parameters / appropriate treatment of nuclear investment

Docket No. 454-95-0966.G - Texas Automobile Insurance Plan Association Rate Hearing; cost of capital / profit factor

Docket No. 454-95-1218.G - Private Passenger and Commercial Automobile Insurance Benchmark Rate Hearing; cost of capital / profit factor

Docket No. 454-95-1280.G - Residential Property and Catastrophe Insurance Rate Hearing - cost of capital / profit factor

Docket No. 454-96-1640.G - Texas Automobile Insurance Plan Association Rate Hearing; cost of capital / capital structure

Docket No. 454-96-1639.G - Private Passenger and Commercial Automobile Insurance Benchmark Rate Hearing; cost of capital / capital structure

Docket No. 454-96-1638.G - Residential Property and Catastrophe Insurance Rate Hearing - cost of capital / capital structure

Docket No. 454-98-0224.G - Texas Automobile Insurance Plan Association Rate Hearing; cost of capital / capital structure

Docket No. 454-97-2106.G - Private Passenger and Commercial Automobile Insurance Benchmark Rate Hearing; cost of capital / profit factor

Docket No. 454-97-2107.G - Residential Property and Catastrophe Insurance Rate Hearing - cost of capital / profit factor

Docket No. 454-99-0408.G - Private Passenger and Commercial Automobile Insurance Benchmark Rate Hearing; cost of capital / profit factor

Docket No. 454-99-0294.G - Residential Property and Catastrophe Insurance Rate Hearing - cost of capital / profit factor

Docket No. 454-99-1332.G - Texas Automobile Insurance Plan Association Rate Hearing; cost of capital / capital structure

Docket No. 22344 – Texas Universal Cost of Service Hearings – capital structure / cost of capital

Docket No. GUD 9400 (Before the Texas Railroad Commission) – TXU Gas – capital structure/ cost of capital

Docket No. 28840 – AEP Texas Central Company – capital structure / economic environment / cost of capital

Docket No. 32093 – Centerpoint Energy – capital structure/ cost of capital

Docket Nos. 33309 and 33310 – AEP Texas Central Company and AEP Texas North Company – capital structure / economic environment / cost of capital

Docket No. 38929 – Oncor Electric Delivery Company, LLC – capital structure / cost of equity capital / overall cost of capital

Docket No. 38480 – Texas-New Mexico Power Company – capital structure / cost of equity / overall cost of capital

UTAH

Testimony on behalf of: The Committee of Consumer Services

Docket No. 97-049-08 – US WEST Communications – cost of capital/ relative risk/ capital structure / financial cross-subsidization

VERMONT

Testimony on behalf of : Vermont Department of Public Service

Docket No. 5282 - Green Mountain Power Company; cost of capital / capital structure / relative risk

Docket No. 5370 - Green Mountain Power Company; cost of capital / capital structure / unregulated operations

Docket No. 5428 - Green Mountain Power Company; cost of capital / capital structure / relative risk / unregulated operations

Docket No. 5678 - Green Mountain Power Company; cost of capital / capital structure

Docket No. 5700 - New England Telephone - Vermont; capital structure/ operating risk/ cost of equity capital / competitive risk

Docket No. 5724 - Central Vermont Public Service - capital structure / historical operating risk / cost of equity capital

Docket No. 5713 – Phase II – New England Telephone (d/b/a – Bell Atlantic – Vermont) – capital structure / cost of equity capital / TELRIC proceeding

Docket NO. 6167 – Bell Atlantic – Vermont – alternative regulatory plant / capital structure / cost of capital

Docket No. 7336 – Central Vermont Public Service – capital structure / cost of equity / overall cost of capital

VIRGINIA

Testimony on behalf of the Division of Consumer Council, Office of the Attorney General

SCC Case No. INS940101 – Workers Compensation Benchmark Rate Proceeding - Cost of capital and relative risk issues in assigned risk workers compensation insurance.

Case No. PUC950019 - GTE South, Incorporated - capital structure / re-engineering adjustment to equity capital / cost of equity capital

SCC Case No. INS960191 - Workers Compensation Benchmark Rate Proceeding - Cost of equity capital, capital structure, investment return

Case No. PUE 960227 – Virginia Natural Gas – cost of capital/ capital structure

Case No. PUE-2009-00019 – Virginia Dominion Power – statutory allowed return / capital structure / cost of capital.

Case No. PUE-2011-00027 – Virginia Dominion Power – statutory allowed return / capital structure / cost of capital.

WASHINGTON

Testimony on behalf of : Attorney General's Office, and Washington Utilities and Transportation Commission Staff

Docket No. UT-901033 - Local Exchange Carrier Rates of Return Under WAC 480-80-390; economic environment and changes in capital cost rates / LEC risk / telco population density and risk / equity capital cost

Docket No. UG-920840 - Washington Natural Gas Company; cost of capital / capital structure / weather normalization

Docket No. UE-921262-Puget Sound Power & Light; cost of capital, capital structure, impact of decoupling on risk and return, purchased power risk.

Docket No. UT-931591, GTE Northwest, capital structure/ operating risk/ cost of equity capital / competitive risk.

Docket No. UT-950200, US WEST Communications, capital structure/ operating risk/ cost of equity capital

Docket No. UE-991832, Pacificorp, capital structure/ cost of equity capital.

Docket Nos. UE-991606 and UE-991607 – Avista Corporation, capital structure.operating risk/ cost of equity capital.

Docket No. UG-011570/1-Puget Sound Power & Light; Interim/Emergency Rate Case/ financial need / bond rating impact of purchased power losses

Docket No. UG-031885 – Northwest Natural Gas; capital structure / cost of common equity capital

Docket No. UE-032065 – Pacificorp; capital structure / cost of common equity capital

Docket No. UE-040640000/UG-040641 – Puget Sound Energy; capital structure / cost of common equity capital

Docket No. UE-050684 – Pacificorp; cost of common equity / capital structure / overall cost of capital

Docket No. UE-0501090 – Pacificorp/Mid-American Energy Holding Company Merger Application; financial aspects of merger / leverage at parent company

Docket No. UT-051291 – Sprint/Nextel – Merger/Spin-off of regulated telephone operations; financial aspects of spin-off / leverage at parent company

Docket Nos. UE-050482 & UG-050483 - Avista Utilities – testimony on cost of equity capital / capital structure / economic environment

Docket Nos. UE-060266/UG-060267 – Puget Sound Energy, cost of equity capital/ capital structure/ overall cost of capital

Docket Nos. UE-072300/UG-072301 – Puget Sound Energy, cost of equity capital/ capital structure/ overall cost of capital

Docket Nos. UE-072375 – Puget Holdings LLC and Puget Energy, acquisition proposal by private equity firm for utility operations of Puget Energy

Docket Nos. UE-090704/UG-090705— Puget Sound Energy, cost of equity capital/ capital structure and costs associated with private equity corporate structure/ overall cost of capital

Docket No. UT-090842—Frontier Communications/Verizon merger; Financial Issues related to merger.

WISCONSIN

Testimony on behalf of: Wisconsin Citizens' Utilities Board

Docket Nos. 9403-YI-100 and 6680-UM-100 – Alliant Energy – merger-related issues/unregulated investment limitation

Docket No. 6680-UR-112, Wisconsin Power & Light – capital structure / cost of common equity / overall cost of capital

Docket No. 6680-CE-171, Wisconsin Power & Light – cost of common equity / fixed rate of return for wind generating plant

Docket No. 6680-CE-170, Wisconsin Power & Light – cost of common equity / fixed rate of return for coal generating plant

Docket No. 05-UR0104, Wisconsin Power & Light – Wisconsin treatment of OBS (off-balance sheet) obligations in the ratemaking process/ cost of capital.

EASTERN CARIBBEAN TELECOMMUNICATIONS AUTHORITY (ECTEL)

Testimony on behalf of: ECTEL

(No Docket Number) Initial Rate Determination of Cable & Wireless local exchange telcommunications operations – capital structure/ relative risk/ cost of equity/ risk premium for investing in Easter Caribbean/ overall cost of capital.

FEDERAL COMMUNICATIONS COMMISSION

Testimony on behalf of : Consumer Advocate Division of the WV Public Service Commission

Docket No. 89 - 624 - Represcribing the Authorized Rate of Return for Interstate Services of Local Exchange Carriers; statement in response to initial submission of telephone companies.

FEDERAL ENERGY REGULATORY COMMISSION

Testimony on behalf of : Consumer Advocate Division of the WV Public Service Commission, Maryland Peoples' Counsel, Pennsylvania Office of Consuemr Advocate

Docket No. 84-348 - American Electric Power Company, Transmission Equalization Agreement; cost of equity capital

Docket No. 86-37 - Allegheny Generating Company (complaint case); cost of capital / capital structure

Docket Nos. 85-19-001 through 005 - Comments on FERC's Generic Determination of Rate of Return on Common Equity for Electric Utilities in response to FERC's Notice of Proposed Rulemaking, July 21, 1986

Docket No. 87-61-000 - Eastern Shore Natural Gas Company; cost of capital / capital structure

Docket No. EL-89-17 and 18 - San Diego Gas and Electric Company v. Alamito Company; Arizona Corporation Commission v. Alamito Company (complaint case), testimony on financial history of Alamito Company, regulation as marketplace surrogate, "sharing" gain on sale leaseback as generic policy, institutional investor responsibility.

Docket No. El-92-10 - Allegheny Generating Company (complaint case); cost of equity capital / relative risk of FERC-regulated subsidiary v. parent / risk premium reliability

Docket No. El-94-24- Allegheny Generating Company (complaint case); cost of equity capital / relative risk of FERC-regulated subsidiary v. parent / risk premium reliability

Docket No. ER98-2383-000 - Montana Power Company – cost of equity for electric transmission, capital structure

Docket No. PL98-2-000 – Conference on the Financial Outlook of the Natural Gas Pipeline Industry, prepared comments for the Pennsylvania Office of Consumer Advocate

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	**CASE NO. 2011-00161**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	**CASE NO. 2011-00162**

**RESPONSE OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
TO KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY'S
DATA REQUESTS**

22. Concerning Mr. Hill's testimony, please provide copies of all electronic spreadsheets used in the development of the analyses and exhibits in their original format, with all formulas intact.

RESPONSE:

Please see folder entitled "HillNativeExhibits", provided on the attached CD.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	**CASE NO. 2011-00161**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	**CASE NO. 2011-00162**

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KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
TO KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY'S
DATA REQUESTS

23. Please provide copies of all documents, articles, studies, or other publications referenced in Mr. Hill's testimony.

<u>RESPONSE:</u>

Please see folder entitled "HillDocuments", provided on the attached CD.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	**CASE NO. 2011-00161**

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RESPONSE OF KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. TO KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY'S DATA REQUESTS

24. Does Mr. Hill agree that bond rating agencies, such as Standard & Poor's, consider the impact of regulation on a utility's risks when evaluating credit ratings? If the answer is anything other than an unqualified "yes," please provide a complete explanation.

RESPONSE:

Yes, however we are not attempting to determine a bond rating for KU or LGE in this proceeding, we are attempting to determine an allowed return on equity that is appropriate given the reduced risks afforded the companies by Kentucky's environmental surcharge regulation.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	**CASE NO. 2011-00161**

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APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	**CASE NO. 2011-00162**

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KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
TO KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY'S
DATA REQUESTS**

25. Please refer to Mr. Hill's testimony at page 3 lines 19-23. Please provide a list of all cost recovery mechanisms applicable to each of the utilities in Mr. Hill's proxy group, including environmental cost recovery trackers. If Mr. Hill did not examine the extent to which his proxy utilities operate under similar adjustment mechanisms, please explain why not.

RESPONSE:

Mr. Hill has not conducted such a study because such data are not readily available, making any such study time-consuming, unnecessarily expensive and, therefore, outside the budget allotted for this proceeding. Rather, Mr. Hill is relying on his 30-year experience in utility regulation to conclude that a regulatory cost-recovery mechanism that allows a utility to recover construction costs from ratepayers within months of the expenditure of those costs is uncommon and indicates that the Companies' environmental plant investments have lower investment risk than that afforded traditional utility plant investment. Therefore, those investments deserve a lower rate of return.