Power Surge Protection

Power Surge puts you in control. You decide on how much coverage is right for you. You can cover your valuable equipment and appliances up to a total value of $5,000. The premiums are based on the amount of protection you choose, starting at $4 per month for $2,000 of coverage.

Take a proactive step. Since no one can predict when and where lightning will strike, it pays to be prepared. Join the more than 86,000 FPL Energy Services customers* who have chosen to protect their appliances and electronic equipment against damages caused by lightning or power surges.

No checks to write. Once enrolled, your insurance plan's monthly premiums will be conveniently added to your FPL bill. There are no extra checks to write or additional bills to mail.

Try it for 30 days with no obligation. You have a right to review this important coverage. If not satisfied, return the policy within the first 30 days for a full credit of any premiums you have paid (minus any claims). Of course, you are free to cancel coverage at any time after that if you wish.

Don't be without this powerful protection. Month after month, you'll enjoy the peace of mind and security that come from knowing you are prepared in the event of a power surge or lightning strike.

* FPL statistics

Important Reminder
for Residential Customers:

We request your authorization to activate optional Power Surge Protection.

Please respond by your payment due date, or call toll-free 1-877-458-5590 and mention offer #521 to enroll immediately.

Here Are Some Facts You Should Know About Lightning:

- Lightning – the most dangerous and frequently encountered weather hazard people experience each year – is the second most frequent weather-related killer in the United States.[1]
- While it is difficult to quantify lightning losses, it is estimated that $4-5 billion in damages occur each year.[1]
- Florida, the lightning capital, experienced 334,317 lightning strikes in 2007 alone.[2]
- Over $5,000,000 in claims has been paid to FPL Energy Services customers with Power Surge Protection to recover damages caused by lightning and power surges.[3]

Don't Be Left Out!

Join the more than 86,000 FPL Energy Services customers[2] who have chosen to protect their appliances and electronic equipment against damages caused by lightning or power surges.

[1]2007 *www.nssl.noaa.gov/primer/lightning/ltg_damage.html*
[2]FPL statistics within FPL service territory
[3]2007 Assurant Solutions statistics

PP22288-0408 mdko
Power Surge Protection

Attention FPL Energy Services Residential Customers:

Your Authorization is Required

Power Surge Protection
Offered on behalf of FPL Energy Services

Power Surge is optional insurance protection that covers the cost to repair or replace your appliances and electronic equipment – everything from the air conditioner to your computer's hard drive – against damage caused by power surges and lightning strikes.

FPL Energy Services has had years of experience dealing with lightning strikes and power surges and knows the damage they cause. While there's no way to completely prevent the damage, Power Surge Protection can provide post-surge recovery for your essential electronics and appliances.

While you may not be able to avoid damage caused by lightning or power surges, you can help reduce the cost of repairing or replacing your damaged appliances and electronic equipment with optional Power Surge Protection insurance. FPL Energy Services and American Bankers Insurance Company of Florida, a leading insurance provider, have teamed up to provide this optional insurance coverage.

Power Surge pays. Power Surge Protection covers the cost to repair or replace your appliances and electronic equipment against the risk of financial loss caused by damage from power surges and lightning strikes. You will be reimbursed for the cost of repair or replacement for covered losses, up to the maximum of your policy. And with Power Surge Protection, you never have to pay a deductible!

Here's what some satisfied FPL Energy Services customers say about **Power Surge Protection:**

"Our claim was handled quickly and [we] had no problems with it. [We are] very happy with all [the] services."
– William A., Venice

"Everyone should enroll [in] this program – especially in Florida."
– Theresa C., West Palm Beach

"We were pleasantly surprised at the quick response and the timely way you paid the claim. Thanks!"
– Donald G., Naples

Power Surge Summary of Exclusions provided by American Bankers Insurance Company of Florida

- Electric appliances and electronic equipment not operational just prior to the peril causing the loss or not owned by the policy owner.
- Electric appliances and electronic equipment that cannot be replaced with other of like kind and quality.
- Additional costs of on-site service, such as travel charges.
- Loss resulting directly or indirectly from enforcement of any ordinance or law regulating the construction, repair or demolition of a building or other structure.
- Loss caused by, or resulting from, depreciation; insects, vermin, corrosion or rust; physical environment such as dust, dampness, dryness, cold and heat; mysterious disappearance; error or omission in design or system configuration; faulty construction or any original defect in the covered property; war including undeclared or civil war; repair or service including installment of covered property.
- Additional costs incurred as a result of a loss, such as extra expenses, programming, data reconstruction, data recovery or program installation or reconfiguration.
- Costs recoverable under the product warranty or extended warranty.

This is a brief description of Power Surge Protection. Please refer to your policy, which you will receive once you enroll, for complete details of coverage and exclusions that apply.

Power Surge protection is underwritten by American Bankers Insurance Company of Florida, an Assurant Solutions company, 11222 Quail Roost Drive, Miami, Florida 33157-6596.

*To enroll, simply complete the enrollment form and mail along with your FPL payment. To enroll by phone, call toll-free **1-877-459-5590** and mention offer #521.*

▲ DETACH HERE AND RETURN WITH YOUR FPL PAYMENT ▲

FPL
Energy Services

PROTECT YOUR BUDGET FROM UNEXPECTED REPAIR BILLS.

☑ **YES! Please enroll me in the Power Surge protection program.**
I understand that the purchase of this insurance is voluntary, and I'm free to cancel at any time.

Please choose one of the following plans:

- ☐ **$5,000 / $10.00 per mo.**
- ☐ **$3,500 / $7.00 per mo.**
- ☐ **$2,500 / $5.00 per mo.**
- ☐ **$2,000 / $4.00 per mo.**

For additional information or immediate enrollment, call toll-free 1-877-459-5590 and mention offer #521. Please have your FPL account number available when you call. *Se habla espanol.*

I hereby give permission to charge my FPL account monthly for the coverage I am purchasing.

ACCOUNTHOLDER'S SIGNATURE			TODAY'S DATE
X			/ /

Please Print

FPL BILL ACCOUNT NUMBER (REQUIRED)			DAYTIME PHONE #
			( )
PRINT ACCOUNTHOLDER'S NAME (REQUIRED)			
ACCOUNTHOLDER'S FLORIDA ADDRESS	CITY	STATE FL	ZIP

Any person who knowingly and with intent to injure, defraud or deceive any insurer files a statement of claim or an application containing any false, incomplete or misleading information is guilty of a felony of the third degree. (Applicable in FL.)
A4270-0900

LICENSED RESIDENT AGENT NAME
LICENSE NUMBER

FPL Energy Services, 6001 Village Blvd., West Palm Beach, FL 33407, Telemarketing License #TC2270.

Power Surge is available to residential customers only.

PP22286-0408 mdko
Power Surge Protection

3757-0005-285-I-0-M-FL-280126U1

TO OPEN - REMOVE THIS STUB AND SLOWLY PEEL BACK TOP SHEET

Attention FPL Energy Services Residential Customers:

Your Signature is Required

Your friends and neighbors enjoy the benefits of Power Surge Protection. Here's what some have said:

"The service could not have been better. We were satisfied completely."
– Louise W., Miami

"Our claim was handled quickly and [we] had no problems with it. [We are] very happy with all [the] services."
– William A., Venice

"Everyone should enroll with Florida Power & Light for this program – especially in Florida."
– Theresa C., West Palm Beach

"We were pleasantly surprised at the quick response and the timely way you paid the claim. Thanks!"
– Donald G., Naples

"Thank you for the fast [and] courteous service. [It] was excellent."
– Keith T., Titusville

Important Reminder

for Residential Customers:

We request your signature to activate optional Power Surge Protection.

Please respond by your payment due date, or call toll-free 1-877-459-5590 and mention offer #621 to immediately process your enrollment.

Damage from lightning and power surges - it happens ... probably more often than you think.*

Did you know?

Power surges can cause:

- Your computer to lose data
- Electronics to overheat
- Household appliances to malfunction

The cost for repair or replacement is expensive and usually NOT covered by homeowner's insurance. So what can you do to prepare for the unexpected?

Enroll in Power Surge protection.

With Power Surge Protection, you will:

- Be reimbursed for the cost to repair or replace your covered appliances and electronic equipment due to damage from power surges and lightning strikes
- Be covered for losses up to the policy maximum
- Never have to pay a deductible!

Safeguard your budget with Power Surge Protection
Offered on behalf of FPL Energy Services

* Florida is the lightning capital of the world. Florida experiences lightning strikes at least 100 days per year. www.aroundcentralflorida.com

55% of Americans mistakenly believe that their homeowners policy covers power surges*.

	Your Homeowners Policy	Power Surge Protection
Coverage for damages from power surges	usually no*	**yes**
Deductible	?	**no**
Increased premium rate after claim	?	**no**
Cancellation after claim	?	**no**

The vast majority of renters and homeowners policies <u>exclude</u> sudden loss or damage to electronics from changes in an artificially generated electrical current. (Survey conducted by Trusted Choice Agencies, 2007).

To enroll, simply complete the enrollment form on the reverse side and mail along with your FPL payment.
To enroll by phone call toll-free 1-877-459-5590 and mention offer #621.

080677 Hearing Exhibit - 00001989

FPL. Energy Services

PROTECT YOUR BUDGET FROM UNEXPECTED REPAIR BILLS.

☑ YES! Please enroll me in the Power Surge protection program. I understand that the purchase of this insurance is voluntary, and I'm free to cancel at any time.

I hereby give permission to charge my FPL account monthly for the coverage I am purchasing.

Please choose one of the following plans:

- ☐ $5,000 / $10.00 per mo.
- ☐ $3,500 / $7.00 per mo.
- ☐ $2,500 / $5.00 per mo.
- ☐ $2,000 / $4.00 per mo.

For additional information or immediate enrollment, call toll-free 1-877-459-5590 and mention offer #621. Please have your FPL account number available when you call. *Se habla espanol.*

ACCOUNTHOLDER'S SIGNATURE X	TODAY'S DATE / /

Please Print

FPL BILL ACCOUNT NUMBER (REQUIRED)		DAYTIME PHONE # ( )
PRINT ACCOUNTHOLDER'S NAME (REQUIRED)		
ACCOUNTHOLDER'S FLORIDA ADDRESS CITY	STATE FL	ZIP

Any person who knowingly and with intent to injure, defraud or deceive any insurer files a statement of claim or an application containing any false, incomplete or misleading information is guilty of a felony of the third degree. (Applicable in FL.)

A4270-0900

LICENSED RESIDENT AGENT NAME
LICENSE NUMBER

PP22287-0508 mdhp
Power Surge Protection

FPL Energy Services, Telemarketing License #TC2270
6001 Village Blvd., West Palm Beach, FL 33407

Power Surge is available to residential customers only. 3757-0005-285-I-0-M-FL-28147U1

Power Surge Summary of Exclusions provided by American Bankers Insurance Company of Florida

- Electric appliances and electronic equipment not operational just prior to the peril causing the loss or not owned by the policy owner.
- Electric appliances and electronic equipment that cannot be replaced with other of like kind and quality.
- Additional costs of on-site service, such as travel charges.
- Loss resulting directly or indirectly from enforcement of any ordinance or law regulating the construction, repair or demolition of a building or other structure.
- Loss caused by, or resulting from, depreciation; insects, vermin, corrosion or rust; physical environment such as dust, dampness, dryness, cold and heat; mysterious disappearance; error or omission in design or system configuration; faulty construction or any original defect in the covered property; war including undeclared or civil war; repair or service including installment of covered property.
- Additional costs incurred as a result of a loss, such as extra expenses, programming, data reconstruction, data recovery or program installation or reconfiguration.
- Costs recoverable under the product warranty or extended warranty.

This is a brief description of Power Surge Protection. Please refer to your policy, which you will receive once you enroll, for complete details of coverage and exclusions that apply.

Power Surge protection is underwritten by American Bankers Insurance Company of Florida, an Assurant Solutions company, 11222 Quail Roost Drive, Miami, Florida 33157-6596.

The one who benefits in so many ways from Power Surge Protection is You.

- **You decide.** You can protect your appliances and electronics up to a value of $5,000. Premiums start at $4 per month for $2,000 of coverage.
- **You can join the more than 86,000 FPL customers enrolled in Power Surge Protection.*** And enjoy protection when needed (over $5,000,000 in claims has been paid to customers with Power Surge Protection).**
- **You can enjoy coverage for repair or replacement.** Can't be repaired? You will be reimbursed for a replacement up to the policy limit.
- **You don't have to write any extra checks.** Monthly premiums will be conveniently added to your FPL bill.
- **You have nothing to lose.** Review your coverage for 30 days. If you're not satisfied, simply return the policy within the first 30 days for a full credit of any premiums you have paid (minus any claims).

* FPL Energy Services statistics
** Assurant Solutions statistics, 2007

PP22287-0508

080677 Hearing Exhibit - 00001992

TO OPEN - REMOVE THIS STUB AND SLOWLY PEEL BACK TOP SHEET

Are You Covered for Power Surges?

Like a majority of Americans, you may think your homeowners policy has you covered.

But are you?

(open now)

WARNING

Damage from lightning and power surges – it happens ... probably more often than you think.*

Did you know?

Power surges can cause:

- Your computer to lose data
- Electronics to overheat
- Household appliances to malfunction

The cost for repair or replacement is expensive and usually NOT covered by homeowners insurance. So what can you do to prepare for the unexpected?

Enroll in Power Surge protection.

With Power Surge Protection, you will:

- Be reimbursed for the cost to repair or replace your covered appliances and electronic equipment due to damage from power surges and lightning strikes
- Be covered for losses up to the policy maximum
- Never have to pay a deductible!

* Florida is the lightning capital of the world. Florida experiences lightning strikes at least 100 days per year. www.aroundcentralflorida.com

080677 Hearing Exhibit - 00001994

55% of Americans mistakenly believe that their homeowners policy covers power surges.**

	Your Homeowners Policy	Power Surge Protection
Coverage for damages from power surges	usually no**	yes
Deductible	?	no
Increased premium rate after claim	?	no
Cancellation after claim	?	no

** *The vast majority of renters and homeowners policies exclude sudden loss or damage to electronics from changes in an artificially generated electrical current. (Survey conducted by Trusted Choice Agencies, 2007).*

To enroll, simply complete the enrollment form on the reverse side and mail along with your EPL payment.
To enroll by phone, call toll-free 1-877-459-5590 and mention offer #[xxx]

Your friends and neighbors enjoy the benefits of *Power Surge Protection.*

Here's what some have said:

"I didn't realize our refrigerator had computer boards and when the technician told me the cost I didn't expect (Assurant) to pay the total repair cost. I was pleasantly surprised when I received a check a few weeks later for the full amount."
- James M., North Venice

"After purchasing the program I heard reports that having claims processed was lengthy and complicated. Exactly the opposite was true. I received a very fair refund in a timely manner."
- James F., Sarasota

"Service was timely and competent. Customer Service was helpful and explained what I had to do to file my claim in a competent, professional manner."
- Wayne R., Palm Coast

"I think it is wonderful coverage, even reimbursement for Tech charges to see if they could be repaired or replaced."
- JR D., Yulee

PP22498-0808 bl np

Safeguard your budget with *Power Surge Protection*

Offered on behalf of FPL Energy Services

Enroll today.

It's easy. Simply complete the enrollment form and mail along with your FPL payment by your due date. To enroll by phone, call toll-free **1-877-459-5590** and mention offer # [XXX].

PP22406-0608 athp

FPL
EnergyServices

PROTECT YOUR BUDGET FROM UNEXPECTED REPAIR BILLS.

For additional information or immediate enrollment, call toll-free 1-877-459-5590 and mention offer #[XXX]. Please have your FPL account number available when you call. *Se habla español.*

☑ **YES! Please enroll me in the Power Surge protection program. I understand that the purchase of this insurance is voluntary, and I'm free to cancel at any time.**

I hereby give permission to charge my FPL account monthly for the coverage I am purchasing.

Please choose one of the following plans: ☐ **$5,000 / $10.00 per mo.** ☐ **$3,500 / $7.00 per mo.** ☐ **$2,500 / $5.00 per mo.**

ACCOUNTHOLDER'S SIGNATURE	TODAY'S DATE
X	/ /

Please Print

FPL BILL ACCOUNT NUMBER (REQUIRED)		DAYTIME PHONE #
		( )
PRINT ACCOUNTHOLDER'S NAME (REQUIRED)		
ACCOUNTHOLDER'S FLORIDA ADDRESS CITY	STATE FL	ZIP

FPL Energy Services, Telemarketing License #TC2270, 6001 Village Blvd., West Palm Beach, FL 33407

Any person who knowingly and with intent to injure, defraud or deceive any insurer files a statement of claim or an application containing any false, incomplete or misleading information is guilty of a felony of the third degree. (Applicable in FL.)
A4270-0900

Power Surge is available to residential customers only.

LICENSED RESIDENT AGENT NAME
LICENSE NUMBER

XXXX-XXXX-XXX-X-X-FL-XXXXXU1

PP22498-0808 ahhp
Power Surge Protection

080677 Hearing Exhibit - 00001998

Power Surge Summary of Exclusions provided by American Bankers Insurance Company of Florida

- Electric appliances and electronic equipment not operational just prior to the peril causing the loss or not owned by the policy owner.
- Electric appliances and electronic equipment that cannot be replaced with other of like kind and quality.
- Additional costs of on-site service, such as travel charges.
- Loss resulting directly or indirectly from enforcement of any ordinance or law regulating the construction, repair or demolition of a building or other structure.
- Loss caused by, or resulting from, depreciation; insects, vermin, corrosion or rust; physical environment such as dust, dampness, dryness, cold and heat; mysterious disappearance; error or omission in design or system configuration; faulty construction or any original defect in the covered property; war including undeclared or civil war; repair or service including installment of covered property.
- Additional costs incurred as a result of a loss, such as extra expenses, programming, data reconstruction, data recovery or program installation or reconfiguration.
- Costs recoverable under the product warranty or extended warranty.

This is a brief description of Power Surge Protection. Please refer to your policy, which you will receive once you enroll, for complete details of coverage and exclusions that apply.

Power Surge protection is underwritten by American Bankers Insurance Company of Florida, an Assurant Solutions company, 11222 Quail Roost Drive, Miami, Florida 33157-6596.

The one who benefits in so many ways from Power Surge Protection is You.

- You decide. You can protect your appliances and electronics up to a value of $5,000. Premiums start at $4 per month for $2,000 of coverage.
- You can join the more than 86,000 FPL customers enrolled in Power Surge Protection***. And enjoy protection when needed (over $5,000,000 in claims has been paid to customers with Power Surge Protection)†.
- You can enjoy coverage for repair or replacement. Can't be repaired? You will be reimbursed for a replacement up to the policy limit.
- You don't have to write any extra checks. Monthly premiums will be conveniently added to your FPL bill.
- You have nothing to lose. Review your coverage for 30 days. If you're not satisfied, simply return the policy within the first 30 days for a full credit of any premiums you have paid (minus any claims).

*** FPL Energy Services statistics

† Assurant Solutions statistics, 2007

PP22498-0808 ahhp

080677 Hearing Exhibit - 00002000

TO OPEN - REMOVE THIS STUB AND
BLOW? PEEL BACK TOP SHEET

FPL
EnergyServices

ATTENTION: Important Information Enclosed

PLEASE OPEN IMMEDIATELY

Important Notice: The appliances and electronics that make your house a home may be at risk.

It's a concern ...

The appliances and electronics that you depend on and enjoy could be damaged or destroyed by a power surge. A power surge can cause computer crashes and data losses. Stereos, televisions and household appliances can be damaged beyond repair.

- Repairs are costly.
- Replacement can become a major expense.

What can you do?

Enroll in Power Surge Protection.

With Power Surge Protection, you will:

- Be reimbursed for the cost to repair or replace your covered appliances and electronic equipment due to damage from power surges and lightning strikes.
- Be covered for losses up to the policy maximum.
- Choose the coverage that's right for you: from $2,500 to $6,500.
- Never have to pay a deductible!

Protect your electronics and appliances with
Power Surge Protection

Offered on behalf of FPL Energy Services

Why worry about power surges?
Because they can happen every day and you may not be covered.

55% of Americans mistakenly believe that their homeowners policy covers power surges*.

	Your Homeowners Policy	[illegible]
Coverage for damages from power surges	usually no*	**yes**
Deductible	?	**no**
Increased premium rate after claim	?	**no**
Cancellation after claim	?	**no**

** The vast majority of renters and homeowners policies exclude sudden loss or damage to electronics from changes in an artificially generated electrical current. (Survey conducted by Trusted Choice Agencies, 2007).*

To enroll, simply complete the enclosed enrollment form and mail along with your FPL payment.
*To enroll by phone, call toll-free **1-877-459-5590** and mention offer **#932**.*

PP22489-0908 ah-hp

Those who know the valuable benefits of Power Surge Protection* have said:

"This was a wonderful program considering the amount of power outages we experience during the summer months. We were happy to have the opportunity to warrant our major appliances at an affordable price."
– Walter M., Venice

"I am very grateful for your service. Everyone was very courteous. I could not afford to buy a new air conditioner. We were without air (conditioning) for 4 weeks. I am very thankful I had this insurance."
– Juanita N., Port Orange

"Very efficient and I just recently increased the limit of coverage insurance. Living in Florida, you never know what could happen."
– Barbara S., Ft. Myers

"We were pleased to receive full remuneration for a 12-year old T.V. and felt the insurance was well worth the cost."
– Ruth H., Boynton Beach

"The best $5.00 per month I've ever spent! And your company was fantastic!"
– Anne W., Ft. Lauderdale

* Over $5,000,000 in claims has been paid to FPL Energy Services customers with Power Surge Protection to recover damages caused by lightning and power surges. *Source: 2007 Assurant Solutions statistics*

Join those who know how Power Surge protects costly electronics and appliances.*

Enroll today.

It's easy. Simply complete the enrollment form and mail along with your FPL payment by your due date. To enroll by phone, call toll-free ***1-877-459-5590*** and mention offer ***#932***.

* FPL Energy Service statistic: More than 86,000 FPL customers have enrolled in Power Surge Protection.

FPL
Energy Services

PROTECT YOUR BUDGET FROM UNEXPECTED REPAIR BILLS.

For additional information or immediate enrollment, call toll-free *1-877-459-5590* **and mention offer** *#932*. **Please have your FPL account number available when you call. *Se habla español.***

☑ **YES! Please enroll me in the Power Surge Protection program. I understand that the purchase of this insurance is voluntary, and I'm free to cancel at any time.**

I hereby give permission to charge my FPL account monthly for the coverage I am purchasing.

Please choose one of the following plans:

☐ **$2,500 / $5.00 per mo.** ☐ **$5,000 / $10.00 per mo.**
☐ **$3,500 / $7.00 per mo.** ☐ **$6,500 / $13.00 per mo.**

ACCOUNTHOLDER'S SIGNATURE	TODAY'S DATE / /

Please Print

FPL BILL ACCOUNT NUMBER (REQUIRED)	TODAY'S DATE ( )
PRINT ACCOUNTHOLDER'S NAME (REQUIRED)	

ACCOUNTHOLDER'S FLORIDA ADDRESS	CITY	STATE	ZIP
		FL	

Any person who knowingly and with intent to injure, defraud or deceive any insurer files a statement of claim or an application containing any false, incomplete or misleading information is guilty of a felony of the third degree. (Applicable in FL.) A4270-0900

Power Surge is available to residential customers only.

LICENSED RESIDENT AGENT NAME
LICENSE NUMBER

3757-0006-285-I-0-M-FL-280736U1

FPL Energy Services, Telemarketing License #TC2270, 6001 Village Blvd., West Palm Beach, FL 33407

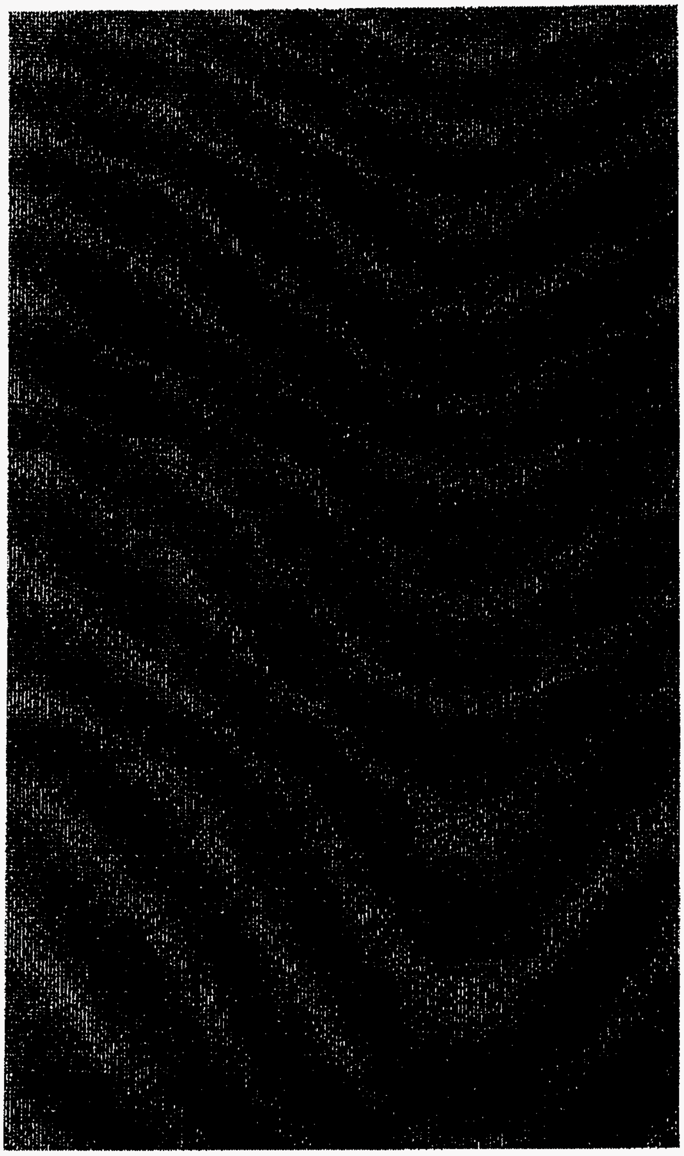
PP22499-0908 ahhp
Power Surge Protection

Power Surge Summary of Exclusions provided by American Bankers Insurance Company of Florida

- Electric appliances and electronic equipment not operational just prior to the peril causing the loss or not owned by the policy owner.
- Electric appliances and electronic equipment that cannot be replaced with other of like kind and quality.
- Additional costs of on-site service, such as travel charges.
- Loss resulting directly or indirectly from enforcement of any ordinance or law regulating the construction, repair or demolition of a building or other structure.
- Loss caused by, or resulting from, depreciation; insects, vermin, corrosion or rust; physical environment such as dust, dampness, dryness, cold and heat; mysterious disappearance; error or omission in design or system configuration; faulty construction or any original defect in the covered property; war including undeclared or civil war; repair or service including installment of covered property.
- Additional costs incurred as a result of a loss, such as extra expenses, programming, data reconstruction, data recovery or program installation or reconfiguration.
- Costs recoverable under the product warranty or extended warranty.

This is a brief description of Power Surge Protection. Please refer to your policy, which you will receive once you enroll, for complete details of coverage and exclusions that apply.

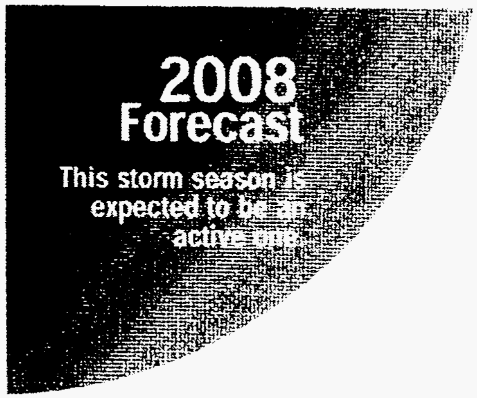
Power Surge Protection is underwritten by American Bankers Insurance Company of Florida, an Assurant Solutions company, 11222 Quail Roost Drive, Miami, Florida 33157-6596.



TO OPEN – REMOVE THIS STUB AND SLOWLY PEEL BACK TOP SHEET

Summertime

080677 Hearing Exhibit - 00002009



Safeguard your budget with *Power Surge Protection*

Offered on behalf of FPL Energy Services

What does this mean to you?

- Your home appliances and electronics could stand a greater chance of damage by lightning strikes and power surges
- Power surges are generally considered the most destructive type of electrical power disturbances.* They can blow out a computer. Stereos, televisions and household appliances can be damaged beyond repair

What can you do?

Enroll in Power Surge Protection.

With Power Surge Protection, you will:

- Be reimbursed for the cost to repair or replace your covered appliances and electronic equipment due to damage from power surges and lightning strikes.
- Be covered for losses up to the policy maximum.
- Never have to pay a deductible!

* www.naturalhandyman.com

080677 Hearing Exhibit - 00002010

Why worry about power surges?

Because they can happen every day.

- Large power surges, as happens with a lightning strike, can cause instantaneous "frying" of electronics and appliances.*
- Even low level surges can degrade internal circuitry until electronics or appliances ultimately fail.

Consider the facts:**

- The average American home experiences five or more power surges each day – or more than 2,000 each year.
- Power surges can travel not only through electrical lines, but also telephone, cable and satellite connections as well.
- More than 40 percent of all computer crashes and data losses are caused by power surges.
- The average home today has over 25 motor driven appliances and several thousand dollars worth of sensitive electronic equipment – all of them vulnerable to the damaging effects of power surges.

* Florida is the lightning capital of the world. Florida experiences lightning strikes at least 100 days per year. www.aroundcentralflorida.com

** www.powerhousetv.com

Then make a wise decision.

Sign up for Power Surge Protection.

With Power Surge Protection:

- you are prepared.
- you have peace of mind knowing your expensive appliances and electronics are covered.
- you are in control – choose how much coverage is right for you: from $2,000 to $5,000 coverage

PP22489-0808 abhp

Join those who know how Power Surge protects costly electronics and appliances.

Enroll today.

It's easy. Simply complete the enrollment form and mail along with your FPL payment by your due date. To enroll by phone, call toll-free ***1-877-459-5590*** and mention offer [***#xxx***].

FPL Energy Services

For additional information or immediate enrollment, call toll-free 1-877-459-5590 and mention offer #[XXX]. Please have your FPL account number available when you call. *Se habla español.*

☐ **YES! Please enroll me in the Power Surge protection program. I understand that the purchase of this insurance is voluntary, and I'm free to cancel at any time.**

I hereby give permission to charge my FPL account monthly for the coverage I am purchasing.

Please choose one of the following plans: ☐ **$5,000 / $10.00 per mo.** ☐ **$3,500 / $7.00 per mo.** ☐ **$2,500 / $5.00 per mo.**

ACCOUNTHOLDER'S SIGNATURE	TODAY'S DATE
X	/ /

Please Print

FPL BILL ACCOUNT NUMBER (REQUIRED)	DAYTIME PHONE #
	( )

PRINT ACCOUNTHOLDER'S NAME (REQUIRED)		
ACCOUNTHOLDER'S FLORIDA ADDRESS CITY	**STATE** FL	**ZIP**

FPL Energy Services, Telemarketing License #TC2270, 6001 Village Blvd., West Palm Beach, FL 33407

Any person who knowingly and with intent to injure, defraud or deceive any insurer files a statement of claim or an application containing any false, incomplete or misleading information is guilty of a felony of the third degree. (Applicable in FL.) A4270-0900

Power Surge is available to residential customers only.

LICENSED RESIDENT AGENT NAME
LICENSE NUMBER

XXXX-XXXX-XXX-X-X-FL-XXXXXU1

PP22499-0808 ahhp
Power Surge Protection

Power Surge Summary of Exclusions provided by American Bankers Insurance Company of Florida

- Electric appliances and electronic equipment not operational just prior to the peril causing the loss or not owned by the policy owner.
- Electric appliances and electronic equipment that cannot be replaced with other of like kind and quality.
- Additional costs of on-site service, such as travel charges.
- Loss resulting directly or indirectly from enforcement of any ordinance or law regulating the construction, repair or demolition of a building or other structure.
- Loss caused by, or resulting from, depreciation; insects, vermin, corrosion or rust; physical environment such as dust, dampness, dryness, cold and heat; mysterious disappearance; error or omission in design or system configuration; faulty construction or any original defect in the covered property; war including undeclared or civil war; repair or service including installment of covered property.
- Additional costs incurred as a result of a loss, such as extra expenses, programming, data reconstruction, data recovery or program installation or reconfiguration.
- Costs recoverable under the product warranty or extended warranty.

This is a brief description of Power Surge Protection. Please refer to your policy, which you will receive once you enroll, for complete details of coverage and exclusions that apply.

Power Surge protection is underwritten by American Bankers Insurance Company of Florida, an Assurant Solutions company, 11222 Quail Roost Drive, Miami, Florida 33157-6596.

Those who know the valuable benefits of *Power Surge Protection** have said:

"This was a wonderful program considering the amount of power outages we experience during the summer months. We were happy to have the opportunity to warrant our major appliances at an affordable price."
- Walter M., Venice

"I am very grateful for your service. Everyone was very courteous. I could not afford to buy a new air conditioner. We were without air (conditioning) for 4 weeks. I am very thankful I had this insurance."
- Juanita N., Port Orange

"Very efficient and I just recently increased the limit of coverage insurance. Living in Florida, you never know what could happen."
- Barbara S., Ft. Myers

"We were pleased to receive full remuneration for a 12-year old T.V. and felt the insurance was well worth the cost."
- Ruth H. Boynton Beach

"The best $5.00 per month I've ever spent! And your company was fantastic!"
- Anne W., Ft. Lauderdale

* Over $5,000,000 in claims has been paid to FPL Energy Services customers with Power Surge Protection to recover damages caused by lightning and power surges. *Source: 2007 Assurant Solutions statistics*

PP22490-0808 ehhp

080677 Hearing Exhibit - 00002016

Electronics: a popular holiday gift

Safeguard them from damage with

Power Surge Protection

offered on behalf of FPL Energy Services.

Don't let a power surge take the joy out of the holidays.

You've saved to make some big purchases this holiday season. You brought them home to a family that will be thrilled. They can enjoy them during the holidays and long after.

But a power surge can occur at any time, damaging your wonderful holiday gifts and leaving you to face the high cost of repair or replacement ... unless you have Power Surge Protection.

With Power Surge Protection, you will:

- Be reimbursed for the cost to repair or replace your covered electronic equipment due to damage from power surges.
- Be covered for losses up to the policy maximum.
- Never have to pay a deductible!

Contact us today! A representative will assist you with coverage tailored to your needs, starting at $5.00 per month for $2,500 of protection.

FPL Energy Services

CALL 1-877-459-5590; mention offer #PWR08

080677 Hearing Exhibit - 00002017

Over $5,000,000 in claims has been paid to FPL Energy Services customers with Power Surge Protection to recover damages caused by lightning and power surges.* Here's what some of them had to say:

"Service was timely and competent. Customer Service was helpful and explained what I had to do to file my claim in a competent, professional manner."
– Wayne R., Palm Coast

"The service was very good. It did not take long for my claim to be filed so I was very pleased. I recommended my friends to buy this coverage."
– Jeanette W., Miami

"I think it is a wonderful coverage, even reimbursement for Tech charges ..."
– JR D., Yulee

** Source: 2007 Assurant Solutions statistics*

Power Surge Summary of Exclusions provided by American Bankers Insurance Company of Florida

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FPL Energy Services, Telemarketing License #TC2270
6001 Village Blvd., West Palm Beach, FL 33407

PP22703-1008 ahld
Power Surge Protection

Remember: power surges never take a holiday. Enroll now.

Docket No. 080677-EI
Deposition of
Marlene M. Santos
Late Filed Exhibit 7
Number of Customers
Billed by FPL for FPLES
Page 1 of 1

Below is a table that displays the number of customers billed by FPL on behalf of FPLES' programs for December 2008 and for July 2009. For those FPLES programs that utilize the FPL bill, FPLES compensates FPL accordingly for billing, collection and any other related costs.

Product	# of FPLES Customers Billed thru FPL (2008)	# of FPLES Customers Billed thru FPL (July 2009)	
SurgeShield	88,538	92,402	
Miami Herald Billing	17,894	1,022	{b}
Power Surge	85,025	83,611	
Utility Gard	15,197	14,362	
Appliance Protection Plus	5,309	4,761	
Payment Power	2,746	2,558	
Appliance Gard	2,809	2,763	
Total	**217,518**	**201,479**	

{b} Note: This FPLES arrangement with Miami Herald was terminated in Dec. 2008 and the service is being phased out in 2009.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080677-EI

In re: Petition for increase in rates by Florida Power & Light Company.
________________________________/

TELEPHONE DEPOSITION OF:	KATHLEEN M. SLATTERY
TAKEN AT THE INSTANCE OF:	The FPSC Staff
DATE:	August 21, 2009
TIME:	Commenced at 9:06 a.m. Concluded at 4:08 p.m.
LOCATION:	2540 Shumard Oak Boulevard Tallahassee, Florida
REPORTED BY:	MARY ALLEN NEEL, RPR, FPR Notary Public, State of Florida at Large

ACCURATE STENOTYPE REPORTERS, INC.
2894 REMINGTON GREEN LANE
TALLAHASSEE, FLORIDA 32308
(850)878-2221

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ALSO PRESENT:

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GARY McBEAN
KORY DUBIN
TRICIA MERCHANT
CINDY MILLER
LEW MINSKY
CLARENCE PRESTWOOD
RHODE ROOT
ANNA WILLIAMS

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STIPULATIONS

The following deposition was taken on oral examination, pursuant to notice, for purposes of discovery, for use as evidence, and for such other uses and purposes as may be permitted by the applicable and governing rules. Reading and signing of the deposition transcript by the witness is not waived.

* * *

MS. COWDERY: This is Kathryn Cowdery with the Office of General Counsel at the Public Service Commission. We're here by notice of telephonic deposition for the deposition of Kathleen Slattery in Docket No. 080677, In Re: Petition for increase in rates by Florida Power & Light Company.

I would like to take appearances. And if you could please identify all those people who are in the room, and if someone could identify where you're located, and please identify what company you are representing or you are with.

MS. CLARK: Kathryn, do you want me to start?

MS. COWDERY: Sure.

MS. CLARK: This is Susan Clark with the law firm of Radey, Thomas, Yon & Clark representing FP&L. I'm here today in the Juno offices of FPL, and I have with me Kathleen Slattery, and also Gary

McBean and Lew Minsky. And currently we have Liz Carrero, who will do the swearing in. I understand we also have Kory Dubin participating by phone.

I should also tell you that we may have others from the HR department joining us if we need help in locating a document, but we don't anticipate it at that point.

MS. COWDERY: Okay.

MR. WIGHT: This is Schef Wright. My full name is Robert Scheffel Wright. I'm in my office in Tallahassee. I'm alone. And I represent the Florida Retail Federation.

MS. KAUFMAN: This is Vicki Gordon Kaufman with the law firm of Keefe, Anchors, Gordon & Moyle here in Tallahassee, and I represent the Florida Industrial Power Users Group, and I am by myself.

MR. BECK: And this is Charlie Beck with the Office of Public Counsel in our Tallahassee office, and with me is Tricia Merchant.

MS. COWDERY: Okay. And again, this is Catherine Cowdery with the Florida Public Service Commission, and with me are Jean Hartman, Anna Williams, and Cindy Miller from the Office of General Counsel, and Clarence Prestwood.

Okay. Could we swear in the witness?

(Witness sworn.)

THE NOTARY: What is the fax number I need to send the certificate of oath?

MS. WILLIAMS: The fax number is (850)413-6250.

THE NOTARY: To you attention of?

MS. WILLIAMS: April Vickery.

Thereupon,

KATHLEEN M. SLATTERY

was called as a witness and, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. COWDERY:

Q. Ms. Slattery, my name is Kathryn Cowdery. You were given notice of this deposition for purposes of discovery in PSC Docket No. 080677, In re: Petition for increase in rates by Florida Power & Light Company. I'm going to go over a few preliminary matters with you.

I'm going to be asking you clear questions, and I would like clear answers to the questions. If the question or a part of the question or word is confusing, ambiguous, or not intelligible, you as the witness are required to let me know, and I will repeat or rephrase the question. If you do not state otherwise, we will assume that the question was clear and you are answering the question that was put to you.

Unless all attorneys agree to go off the record or take a recess, everything that is said is going to be taken down by the court reporter and preserved for use at the time of hearing.

I have the right to ask certain questions, subject to some exceptions that your attorney will handle or to which your attorney will make objection. Unless there is an objection, please answer the question.

If I ask a question and you feel it is necessary to think about it or you need to refresh your recollection with any document or thing that can be supplied, please advise me, and we will give you time to do so.

Do you agree that you will take all the time you need to think about the question, to find any information that may be available to you, and to answer honestly and fully before you answer?

A. Yes, I do.

Q. Private conferences between you and your attorney would be improper, even during recesses, unless the conferences are solely for the purpose of determining whether a privilege should be asserted. When such a conference occurs, the conferring attorney must place on the record the fact that the conference occurred, the subject of the conference, and any decision reached as to whether to assert a privilege. And if --

MS. CLARK: Kathryn, I'm not sure. Can you cite to authority for that statement that you just made?

MS. COWDERY: Not at this time. I think we should just go ahead with this. There's case law on that.

MS. CLARK: Well, I'm sorry. That is not what I have in my notebook on depositions, so I don't agree to it at this time. We can go forward. It may not be an issue.

MS. COWDERY: It may not.

If for any reason you are or become tired and want to take a recess, please say so. I ask only that you not make your request for a recess after a question and before your answer.

Now, given the nature of these depositions and this rate case, if you know someone who has more information on a certain subject than you do and I ask you a question on that subject, please let me know the name and the title of that person.

I may also ask you about time, percentages, or other measurable things. Please understand that your best estimate is just as important to us as the exact amount or a specific number. We would prefer that an estimate be given, if you can give a fair range or a fair estimate, rather than having you simply say, "I don't know exactly."

Now, after the deposition, the court reporter is going to be preparing a transcript, and my understanding is that the transcript is going to be e-mailed to your attorney -- Susan, correct me if I'm wrong on this -- as soon as it is available, which we hope will be this weekend so that you will have an opportunity to read it, make any corrections you see, and sign it. Does that sound like what you were thinking, Susan?

MS. CLARK: Yes. We are not waiving reading of the deposition.

MS. COWDERY: Okay. And if at any time during this deposition, Ms. Slattery, you feel that you need to correct anything that you had said previously in the deposition or make any changes, we would want you to do so.

The notice of telephonic deposition requested that you bring copies of all work papers or other materials used by you in your testimony filed in this docket. Did you bring those documents with you?

MS. CLARK: We've done our best, Kathryn. I think we have what we'll need, and certainly if we don't have it here, we'll go get it. But we made a search, and we brought a number of things that we have piled up around the room, and we believe we have what you need.

MS. COWDERY: Okay.

BY MS. COWDERY:

Q. Ms. Slattery, do you have a copy of your testimony, your direct testimony and your rebuttal testimony with you?

A. Yes, I do.

Q. Well, we are going to start by sort of going through your direct testimony, trying to make it sort of an organized approach to things here.

On page 1 of your testimony, you go over the responsibilities that you have with the company. Are you responsible for the overall design and administration of FPL's compensation and benefits programs for all of FPL's business units?

A. Yes, I am.

Q. Okay. I would like to explore that a little bit. Could you please explain what your responsibilities are with regard to the design of FPL's compensation and benefits programs?

A. Yes. My responsibilities include oversight and management of the compensation staff. We are responsible for the company's overarching philosophy of a total rewards approach, total compensation and benefits, and that includes our philosophy in the design of the total compensation program encompassing base pay, variable performance base pay, and certain other earnings. This would include responsibility for the design and administration of our salary structure and making recommendations to senior leadership regarding our annual merit program.

Q. And how large is your compensation staff, approximately?

A. Between our -- all of our compensation --

MS. CLARK: Kathryn, let me object to that. When you say compensation staff, could you be more specific?

BY MS. COWDERY:

Q. In your answer to me, Ms. Slattery, you said you were responsible for the oversight and management of compensation staff. Could you explain what you mean by compensation staff?

A. There are approximately one dozen people who are compensation analysts or managers in the employee and executive compensation areas.

Q. Okay. And they would all be within your particular unit?

A. Yes, they are all within my unit.

Q. And that's the Human Resources business unit?

A. Yes.

Q. Okay. Could you please explain your responsibilities in the management of the payroll for the HR business unit?

A. Yes. The manager of payroll reports directly to me, and I am responsible for oversight of that department.

Q. Okay. Please explain your responsibilities in the business planning for the HR business unit.

A. The department responsible for HR budgeting and business planning reports directly to me. I have three direct reports in that area, and they each have one direct report.

Q. Do your responsibilities in any way include addressing any issues associated with hiring new employees?

MS. CLARK: Let me object to that question. Hiring new employees, are you speaking again in her business unit?

BY MS. COWDERY:

Q. Ms. Slattery, do your responsibilities in any way include addressing any issues associated with hiring overall for FPL as HR -- you know, in your capacity as HR -- let's see. I can't remember what your title is. For FPL overall?

A. I do not have direct responsibility for hiring, because our recruiting department reports up to another leader. However, my compensation staff does work closely with the recruiters and the business units in making recommendations on compensation packages that are appropriate to offer candidates that we are hiring.

Q. Okay. Do you have anything to do with making a determination of the need for additional staffing for FPL?

A. No, I do not.

Q. Okay. And what person or business unit would be responsible for that, for determining a need for additional staffing?

A. Each business unit is responsible for making that determination with Human Resources/Employee Relations staff supporting them in a consultative role.

Q. And how does your HR staff support them in that role?

A. Because I have never worked in those particular functions, I have limited knowledge of what that role entails and do not want to speculate.

Q. Sure. Okay. Do your responsibilities in any way include addressing issues concerning the record keeping for employees who leave the company?

A. No, they do not.

Q. Does FPL conduct exit interviews with employees concerning their decision to leave FPL for other employment?

A. Yes.

Q. Okay. Who conducts those interviews?

A. Exit interviews are generally conducted by the business units as staff leaves. And again, I believe Human Resources/Employee Relations is support staff for that, acts in a consultative role, and occasionally does perform the exit interviews on behalf of the business unit upon request.

Q. Okay. And what is done with those exit interviews after they're conducted? Are they kept with HR? Are they reviewed by HR?

A. I do not know. That is not part of the scope of my responsibilities, and I've never been involved in it. So I don't know, and I don't want to speculate.

Q. Okay. That's fine. On page 4 of your direct testimony on lines 21 through 23, you testify concerning the number of forecasted employees for 2010. Can you tell me whether these projections agree with your projections in MFR Schedule 35?

A. Yes, they do.

Q. Okay. How many of these employees make more than $165,000 total compensation?

MS. CLARK: Hang on just a minute, Kathryn, if you would. I just want to make sure as to whether that's confidential or not. And I apologize, because I haven't been as intimately involved in that.

(Off the record briefly.)

MS. CLARK: Kathryn, thank you. This is Susan. I just checked, and I understand that the number isn't confidential, so I appreciate it.

A. The number of employees whose compensation exceeded $165,000 in 2008 was 463 employees. I do not have a forecast that is specific for 2009, 2010, or 2011.

Q. Thank you. Can you tell me how many of these employees make more than $200,000 total compensation?

A. I do not know. I did not look at the list and identify that number specifically.

Q. Is that information available that you would be able to find it?

A. I believe I could compute it for you. It's available on FPL's response to Staff Interrogatory 16, and I believe it's 97. It's just a matter of taking that list and adding up which ones were over 200 and which ones were under 200 out of the total 463.

MS. CLARK: Kathryn, would you like us to take a minute and try and do that?

MS. COWDERY: Yes, thank you. That would be very helpful.

Ms. Slattery, while you are making that computation, if you could also tell us what percentage of the employees make more than $200,000 total compensation.

(Off the record briefly.)

MS. CLARK: Kathryn, what we thought we would do is, we would have -- we're going to have someone find that information. And we understand you want the people earning above 200, and then do you want the percentage of employees who are above 200?

MS. COWDERY: Yes. And also, going back to the previous question, we've got 463 employees who make more than 165,000. And what percentage is that, if that's something that can be pulled together for us.

MS. CLARK: And I would expect we could get that probably just a little bit later in the deposition.

MS. COWDERY: That's fine. Thank you.

MS. CLARK: I did want to indicate to you that Rhode Root, who is also with HR, has joined us, and he will be the one trying to help get that information.

MR. ROOT: R-h-o-d-e, and the last name is Root, R-o-o-t.

MS. COWDERY: Thank you.

BY MS. COWDERY:

Q. We're still on page 4, lines 21 to 23, concerning the number of forecasted employees for 2010. How many of these employees are considered executive?

A. Of those that are considered executive, it's my understanding that, again referencing our response to Staff Interrogatory 16, we have budgeted 44 positions executive location wise.

Q. All right. And that would be --

A. If I could check that, because, again, that response was largely based on the 2008 actuals.

Q. Sure. Do you want to check that now?

A. Yes, please.

(Off the record briefly.)

THE WITNESS: I have checked for 2010, using our response to Interrogatory 16 as my source, and the budgeted number of positions for 2010 in the executive location is 42.

BY MS. COWDERY:

Q. Now, is your definition of executives to mean officers, or do you use those terms interchangeably?

A. I will specify, that is officer positions. Yes, we consider our officers to be our executives.

I would note that, as has been disclosed in several of our interrogatories, we do have one position that we don't consider to be an executive who is technically an elected officer of Florida Power & Light Company, and that individual's compensation data was provided with the non-officer positions.

Q. All right. And just so you know, it is very helpful when you do reference specific interrogatory responses. So if you feel like continuing to do that if we ask you a question so we can reference those, that is helpful, so I do appreciate that.

All right. I think you may have answered this, but are all executives in the exempt salaried category?

A. Yes, they are.

Q. And with the understanding that executives are the officers, I think we then have the information, but

I will ask you. How many officers make more than $165,000?

A. All of them.

Q. Okay. Does the total forecasted 11,111 employees for 2010 include contracted or outsourced workers?

A. No, it does not.

Q. Okay. Going to page 5, lines 3 through 6, do the projected total compensation and benefit costs and employee count for 2011 agree and match with the projections in MFR Schedule C-35?

A. Yes, they do.

Q. On page 5, lines 18 through 23, you state, "To that end, FPL continuously monitors and benchmarks the compensation and benefits components of the total rewards package individually, since no composite benchmarks are available for the combined programs, and ensures that the total program is in line with the median of the combined compensation and benefits programs of the appropriate comparator groups."

What are, Ms. Slattery, the individual compensation and benefits components of the total rewards package to which you refer?

A. If I may have a moment to look at my backup to my testimony.

Q. Certainly.

A. As shown in the exhibits to my testimony with regards to benefits, we used a benchmark source that enables us to benchmark the total of all the benefits together, and then also various components individually. The same is true of compensation, where we endeavor to use whatever sources we can to benchmark total compensation, but there we quite frequently have to settle for benchmarking salaries separate from incentive compensation.

Q. Okay. Can you identify what the individual compensation and benefits components are?

A. Yes, I can. With regard to compensation, it's salary and annual incentive. And for a limited number of top management positions, long-term incentive compensation information is also available from our benchmark sources.

With regards to benefits, I need to refer to my rather thick benchmarking report from Hewitt, so if you'll give me just a moment to locate that.

Q. Of course.

(Off the record briefly.)

A. With regard to the benefits benchmarking, we benchmark the total benefits program, and the separate components thereunder include active employee medical plan and pension and 401(k) combined as total retirement plan.

And I do not have any other benchmark surveys with me regarding benefits, but I do believe that there are other components of benefits that we are able to individually benchmark, or benchmark in groupings such as, for example, total health and welfare benefits. I don't have all those documents with me.

Q. So to your recollection, the only individual benefit components that you can recall are active employee medical and the combined pension/401(k)? Those are the only two that you can recall?

A. Those are the two that I recall, yes, but I know that the report that we get from our benchmarking sources, which currently is -- we normally use Hewitt now, and in the past we've also used Towers Perrin -- include additional components of benefits that are benchmarked. I just don't have them with me.

Q. And these are all benefits that you provide your employees, or some of them, but you can't recall what they are at the moment; is that correct?

A. That is correct. However, I've just located our response to an interrogatory, which was System Council U-4's Second Set of Interrogatories, Question Number 39, where we were asked a similar question, and responded that our Hewitt benchmark survey provides benchmarking on the following specific components of benefits. One is pension; 2, 401(k); 3, life insurance or retiree life insurance; 4, short-term disability; 5, long-term disability; 6, medical; 7, dental; 8, vision and hearing; 9, flexible spending account; 10, retiree benefits, i.e., medical, dental, vision, et cetera, and holidays, vacation, and other time off.

Q. Okay. And these are all individual benefits of the total rewards package to which you refer on page 5?

A. Yes, they are.

Q. Okay. Could you please tell me again what interrogatory response that was to?

MS. CLARK: Kathleen, it's SCU-4. I think that was the electrical workers, wasn't it.

THE WITNESS: Yes, SCU-4 IBEW.

MS. CLARK: Kathleen, did you hear that? Kathryn, sorry.

MS. COWDERY: Our court reporter did not.

MS. CLARK: Okay. It's SCU-4, their second set, Question 39. And just for you, Kathryn, it's the IBEW.

MS. COWDERY: Thank you very much.

BY MS. COWDERY:

Q. Ms. Slattery, are there any other forms of compensation available to FPL employees which you have not described in the last question I asked?

A. Yes, there are.

Q. And could you please describe those, however you wish to break it down?

A. In addition to base compensation, base salary, and incentive compensation, which I previously mentioned, other components of pay may include overtime compensation, lump sum awards which are not part of our incentive compensation plan.

Q. Which are not part of what?

A. Which are not part of the annual incentive program.

Q. Okay. Thank you.

A. And other miscellaneous earnings. I can't recall all forms of compensation off the top of my head.

Q. That's fine. Could you give me an idea what the miscellaneous earnings involve?

A. The first thing that comes to mind would be, for example, a sign-on bonus.

Q. Okay.

A. Which is necessary to attract talent from the marketplace. And certain retention forms of compensation where we have a risk of flight in a critical position.

And I can't recall any others. I'm sure there are others. I just haven't memorized all of our numerous wage types.

Q. Sure. Are all forms of compensation available to all employees? And if not, if you could please explain?

A. No, all forms of compensation are not available to all employees. For example, long-term incentive compensation is available only to salaried employees per the terms of that plan document. That is one example of many where a certain category of employee wouldn't be eligible for a form of compensation.

Our bargaining unit employees' compensation is governed by agreement.

Q. Sure.

A. And as a general rule, our non-salaried employees are not eligible for annual incentive compensation.

Q. Okay. Are the benefits packages different between types of employees, you know, health and retirement?

MS. CLARK: Kathryn, I'm going to object to the question. If you would define types of employees, please.

BY MS. COWDERY:

Q. Ms. Slattery, are all forms of benefits available to all employees in the same manner?

A. No, they are not. At the high level, all employees generally have comparable programs available to them. But, of course, for our bargaining unit employees, as an example, the benefits are governed under the collective bargaining agreement, and there are going to be some key differences with those employees that are not covered under the collective bargaining agreement.

Q. Is the total rewards package which is available to employees the same for every employee?

A. No, it is not.

Q. Okay. Could you give an explanation of how it is not?

A. Yes, I can. As I previously described, our employees covered under a collective bargaining agreement are necessarily going to have a slightly different total rewards package than those employees not covered under a collective bargaining agreement.

Q. So essentially, your prior answer having to do with the forms of compensation and the forms of benefits is subsumed under the total rewards package? Those are parts of the total rewards package?

A. I don't understand your question.

Q. Okay. Well, then what I'll do is go back to the question about whether the total rewards package available to employees is the same for every employee. You said no, it is not.

Are there differences regarding the bargaining units, and what other differences are there?

A. Well, another example of difference is that a fundamental element of our compensation and benefits philosophy is the notion that the more responsibility an employee has and the more opportunity that employee has to affect the overall performance of the company, you know, it calls for more of their compensation to be performance-based variable pay to reflect that fact. So therefore, the mix, the pay mix, as we call it, is a little bit different as you go higher up within levels of the company to correspond to that increasing level of responsibility and impact to the results of the company and delivery to customers.

Q. Okay. Now, I'm referring again to your testimony that -- we're still on page 5, lines 18 through 19, where you're talking about continuously monitoring and benchmarking the components individually. How do you continuously monitor and benchmark these components individually?

A. We participate in robust benchmarking processes in both our compensation and benefits department. As described later on in my testimony, we use multiple survey sources to benchmark total compensation and the components of compensation, and we continuously monitor information as it becomes available from the many third-party survey companies that we purchase these surveys from. So if information comes out regarding, you know, planned merit budgets in our industry and general industry, we're constantly subscribing to receive those reports and benchmark data as well.

Q. Is this something that your HR unit does?

A. Yes, it is. It's done by Human Resources.

Q. And why are no composite benchmarks available for the combined programs?

A. We have not found any single company to have gathered that kind of robust information. A lot of it is because of kind of the speciality that benchmarking of benefit values entails, particularly with regard to some very complex calculations around value delivered in 401(k) and pension programs to employees at typical retirement age. Therefore, companies tend to specialize, and the survey data available reflect that.

Q. Now, since there are no composite benchmarks available for the combined programs, to what are you referring on lines 22 and 23 when you're talking about FPL monitoring, et cetera, to ensure that the total program is in line with the median of the combined compensation and benefits programs of the appropriate comparator groups?

A. What that means is that we benchmark our benefits programs, we benchmark our compensation programs, and then we look at the two in their totality to ensure that each is about at median, to give us some assurance and comfort level that our combined programs are at or below median.

Q. And you do this by looking at the individual components that you benchmark; is that correct?

A. Yes. As I described before, it's necessary because of the limited availability of data that would combine those for us, so that is how we do it.

Q. Sure. And what are the appropriate comparator groups to which you refer?

A. That depends on the survey source, quite frankly. For example, when we have the opportunity to look at the companies and identify an appropriate comparator group based on companies that are similar to us, meaning integrated utilities with similar size, complexity and scale, we will ask for what kind of what we call a cut of the survey that reflects that appropriate comparative group. But quite frequently we have to kind of accept whatever utility companies choose to participate in the survey we choose to participate in. So it's largely dictated by who has decided to participate in the survey and subscribe to it and pay to receive it.

MS. COWDERY: Okay. If you'll give me one moment here.

(Off the record briefly.)

BY MS. COWDERY:

Q. Okay. I would like to go to page 6. On lines 5 and 6, you refer to a fixed-cost benefit -- well, actually, fixed-cost benefit programs. Could you please define the term "fixed-cost benefit programs"?

A. Yes, I can. Fixed-cost benefit programs refers to that when you provide a benefits package to an employee, there are certain valuations that are required, whether under Generally Accepted Accounting Principles, or in a budgeting process, or in some cases under a Sarbanes-Oxley process that we've developed around it. So if you provide a certain package of benefits to employees, you can fairly well figure out what you're going to have to expense related to that package in a given year.

And there are very few opportunities to increase or decrease that expense. If you've offered the package to the employee and all the accounting rules, SOX processes, and budgeting processes result in a fixed cost, if you will, then you're somewhat stuck with that cost with no opportunities to be flexible and decrease the expense.

Q. I am going to take one step back and ask you again about the benchmarking we were discussing in the previous question. Has the data you received in the past year from the companies you use for benchmarking shown a decline in the rate of increase in pay and benefits, or even a decline?

A. Well, first of all, there is always going to be a lag time, since companies will spend months gathering up its compensation and benefits data to provide to a survey company, and then the survey company will spend time validating the data in the database, analyzing it, and producing the final report or database. So the most current information available for benchmarking is a little going to reflect that lag time.

Therefore, we have not completed our benchmark studies for, for example, the last 12 months. I mean, we're working on that now. This is the time of year when we are completing receiving the data and analyzing it. In most cases we haven't even received it yet.

So going back in time, we do not have any benchmark survey data that reflects any decline in compensation and benefits packages in our industry or general industry.

We do, however, have information we have purchased from third-party survey companies in the fourth quarter of 2008 and first quarter of 2009, which were provided through a number of PODs, I believe, which show that there was some generally reported consensus across all industries of a small contraction in annual merit budgets for 2009. And FPL followed suit, as demonstrated in my testimony, and we too contracted our merit budget, bringing it back a percent from what we had expected to spend.

But other than that, we do not have any benchmark information that we have received that indicates any reduction in total compensation and benefits packages, no.

Q. So basically, the benchmark information that you have been using is from more than a year ago, just by the nature of how the collection of data and processing of it works?

A. I don't know if I would characterize it as more than a year ago. I would say that we have not received our most recent surveys. It's been about a year. It's generally around September or October that we get access to those new databases.

Q. Okay. Could you tell me FPL's overall employee percentage turnover for the year, say, 2006, just your general turnover rate or percentage?

A. I will have to look that up. Please hold on a moment.

Q. I would be interested in 2006 to -- if you have anything for 2009, if you have that data.

A. I will look through the material I have with me. Please hold on.

Q. Thank you.

(Off the record briefly.)

A. Okay. I've located the data, but could you please repeat the years that you're asking about?

Q. 2006, 2007, 2008, and year-to-date 2009.

A. Okay. For 2006 through 2008, we have historical actuals. This was provided in response to OPC's Second Set of Interrogatories, Question Number 23. For 2006 the turnover was 10 percent. For 2007 it was 9.5 percent. For 2008 it was 8 percent. And we do not have a year-to-date 2009 number, but it is forecasted at year-end 2009 to be 7 percent for the year.

We also have a forecast in that same

interrogatory response for 2010 and 2011. We are forecasting turnover in 2010 to be 9.5 percent, and we're forecasting turnover in 2011 to be 10.4 percent.

Q. Do you have, or can you tell me what your assumptions are for those forecasts, what the cause of the turnover is?

A. I did not prepare those forecasts, so I do not have the assumptions.

Q. Okay. Who prepared those forecasts?

A. A member of the Human Resources Department who works -- he doesn't work in my department, but it is a Human Resources employee.

Q. Can you tell me the name of that employee's department manager or head? I'm just trying to sort of focus in on where that information came from.

A. The employee works for Susan Melians, Vice President, Human Resources, and the employee is the manager of workforce planning, which is an -- he's an analyst.

Q. Do you know that employee's name?

A. Yes. His name is Val Miklausich, M-i-k-l-a-u-s-i-c-h.

Q. Okay. Thank you.

Do you know upon what information the turnover rates for 2006 through 2008 were based?

A. I do not --

Q. That's just actual.

A. Yes, they're actuals. I do not know how they were calculated.

Q. Okay. Are you able to tell me what the turnover rate is for those years for employees making less than $50,000 in total compensation?

A. No. I do not believe that has ever been analyzed separately.

Q. Do you have that information for employees in any other total compensation breakdown, such as between 50,000 and 165,00, or above 165,000?

A. No, we do not.

Q. Okay. Do you have sufficient knowledge to give me an estimate of what the percentage turnover would be for those years for employees making more than $165,000?

A. No.

Q. Is there anyone who might be able to tell me what that information is?

A. No, I don't believe there's anyone who has that information available, subject to check. I would have to inquire.

Q. Do you break down this information between exempt or non-exempt employees?

A. I do believe that we do. I don't have that handy.

MS. CLARK: Kathryn, can Kathleen take just a moment to talk to Gary McBean here?

MS. COWDERY: Yes.

(Off the record briefly.)

A. For that interrogatory response that I'm referencing, which is OPC Second Set, Question Number 123, the turnover figures were provided by position.

Q. Thank you. Could you tell me what percentage of employee turnover for those years is as the result of poaching by other industries?

A. No. I do not know.

Q. Is there someone else who might know this information?

A. I do not believe that there's anybody in Human Resources who has prepared an analysis of that, not to my knowledge.

Q. Okay. If someone did prepare that information, would they be in Human Resources?

A. Yes, they would.

Q. Are you aware of any employees having left FPL in 2006 through 2009 as a result of poaching by other companies?

A. I do hear anecdotal stories from my peers in

Human Resources, particularly with regard to poaching of talent from our Nuclear Division. So throughout the year I hear of names and positions that we lose to, you know, poaching, but I don't have any specific examples here with me today.

Q. Okay. Do you know if anyone would have that specific information?

A. I do not know.

Q. Have you heard of poaching of employees who would be in the lower range, pay scale range, say, less than $50,000 total compensation?

A. Again, my information is anecdotal. Because I don't work in the staffing functions of HR, I don't -- I'm not involved in recruiting. They would obviously know more.

Q. That's fine.

A. But, yes, I certainly hear of anecdotal stories where lower paid employees are subject to poaching, as well as higher paid employees.

Q. Okay. Can you remember anything offhand regarding the lower paid employees, like what positions have been poached?

A. No, I cannot, because most of the stories I hear are in regards to higher levels of employees, because that reflects more of the desired skills and experience in the industry.

Q. Okay. And what can you tell me that you've heard in this regard regarding, you know, specific information about higher level employees in the nuclear area or anywhere else?

A. Well, as I said, this is anecdotal, but I hear frequent stories regarding how, in essence, incestuous the nuclear industry is, because there are a relatively small number of skilled, experienced nuclear workers, a relatively small number of nuclear facilities, and a relatively small number of employers who own those facilities, so the industry has become very incestuous, and there's a lot of -- they call passive sourcing of candidates between companies.

Q. Okay. Have you heard the names of any companies that have poached FPL employees?

A. I have. Again, all my information is anecdotal, and I think that FPL witness Stall may be a better person to ask regarding that, since it's such a significant issue in his business unit.

Q. Okay. That's fine. For purposes of discovery, it's fine for you just to tell us what you've heard. It doesn't have to be your direct knowledge, so that's why I was wondering as far as what have you heard. Have you heard the names of any companies which have actually poached employees from FPL?

A. Well, I frequently hear -- as I said before, I hear of names and positions. I also hear of companies. But I'm not comfortable speculating on something that I hear, you know, third hand.

Q. Okay. I'm going to ask you to tell me the names of any companies that you have heard have poached employees. And I understand that this is just what you have heard, and you are not telling me whether it is true or not.

MS. CLARK: Kathryn, give us a minute.

(Off the record briefly.)

MS. CLARK: Thank you, Kathryn.

MS. COWDERY: Yes.

A. Regarding companies I've heard of poaching our talent, I probably -- and this is not exaggerating -- have heard the name of every employer with a nuclear division having poached from us. But the ones I hear most frequently are Dominion, Excelon, and TVU, Tennessee Valley -- TVA, I'm sorry, TVA, Tennessee Valley Authority, as the most frequent. But again, I've heard of almost all of them -- Entergy as well. Entergy is another big one I hear frequently.

Q. Entergy?

A. Yes.

Q. Is that E-n-t-e-r-g-y?

A. Yes.

Q. All right. And again, understanding that this is only what you have heard, have you heard that specific FPL employees have been poached by Dominion?

A. Yes, anecdotally I have.

Q. Okay. How many employees have you heard of?

A. I have no idea. Again, witness Stall would be the person who would have more information about specific instances and volume of poaching, as well as the relationships between the nuclear employers, as I understand they do actually try to, you know, keep it -- you now, that's something Nuclear deals with. Human Resources doesn't get as involved as Nuclear itself.

Q. Okay. Well, this is very helpful, and I do appreciate it. And I'm going to ask you the same question, but I'll lump them together. Have you heard of any employees specifically being poached by Excelon or by Entergy or by TVA, same question as before?

A. Yes, I have heard, again, of anecdotal stories. But I work in a compensation, benefits, and HR budgeting function that is not directly involved in employee relations and turnover, in hiring, recruiting, filling vacant positions, or dealing with any of the issues around poaching in the Nuclear Division or any others. It is not part of my core responsibilities, and the only information I have is, you know, water cooler talk and things that filter to me through the need to create new competitive compensation offers for filling the turnover we end up with.

Q. So this certainly is not part of the area of your expertise?

A. No, it is not.

Q. So any knowledge you have concerning poaching is really very limited?

A. That is correct. Again, I hear about it all the time, and I do not have any studies on it.

Q. All right. Give me one moment.

All right. On page 9 of your testimony at lines 19 through 21, or 19 through 20, you state that as a result of the total compensation and benefit design changes, FPL and its customers are not nearly as burdened as many other utilities with the considerable cost of pension and post-retirement medical obligations. What other utilities are you referring to?

A. All of them, I mean, all of them that still have traditional post-retirement benefits offered to new hire employees. And this is information that bears out probably on the MFR C-35 filings of other utilities within the State of Florida regarding the projected expense, for example, under FAS 106 for post-retirement medical, where we have a continually declining expense every year rather than an increasing one.

Q. And further down, you say that the changes have allowed the company to better focus on the elements of the total rewards package. Briefly, what are those elements?

A. Are you referring to lines 22 and 23 on page 9?

Q. Correct, correct.

A. The changes have allowed the company to better focus on the elements of the total rewards package that have more value for attraction, retention, and engagement of the required workforce?

Q. Correct.

A. Specifically, we feel that competitive compensation programs, including properly designed incentive compensation programs, are a more effective tool for attracting, retaining, and motivating the workforce than fixed-cost benefit programs like post-retirement medical and pension.

Q. Okay. You continue in your testimony to state, "As a result, the company is able to provide a core level of compensation and benefits to all positions based on market analysis and performance." Could you please define the core level of compensation and benefits which are provided to all positions?

A. The core level would be base pay and the comprehensive benefits package. And the sentence goes on to describe that the company has the flexibility with regard to incentive compensation to respond to the dynamics of the changing workforce, including the need to attract, retain, and motivate a workforce that will deliver on our promises to our customers.

Q. Okay. And to what market analysis and performance do you refer in that sentence?

A. I don't understand your question. I'm sorry. Will you please repeat it or rephrase it?

Q. Sure, sure. You state that as a result, the company is able to provide a core level of compensation and benefits to all positions based on market analysis and performance, and I wanted you to explain what you meant by market analysis and performance.

A. I believe that we've talked previously regarding the market analysis that we perform through our benchmarking sources regarding the individual components of benefits and the total value provided for our core health and welfare programs, post-retirement programs, and overall benefits package. We've also talked about the market analysis that we perform through our benchmark sources on primarily base salary, although we do also have information that we receive from those survey sources on annual incentive compensation, and to a limited extent, long-term compensation.

Q. Okay.

A. Regarding performance, our annual base salary program, which we call our merit program, is a performance-based merit program, meaning that it is not based on a peanut butter approach of spreading compensation increases, but rather a tool that we use to reward and motivate performance as well.

We have very specific guidance that we provide to line supervisors of non-bargaining employees regarding differentiation of annual merit increases based on annual performance appraisals, and then we study that to make sure that there is an appropriate distribution of awards of less than average as to the less-than-average performers and higher than average to the higher performers so that it all averages out to our budget.

Does that answer your question?

Q. Yes, it does. And I'm going to warn you that there's a lot of terminology in your testimony that I will ask you to define your use of certain words, because sometimes it's slightly different, and I just want to make sure that I'm not assuming that when you refer to one type of program that I'm thinking it's another. So just let me know, you know, this is the same as such-and-such that we've discussed, and that will help clarify things for me. I'm just putting you on notice.

Staying on page 10, lines 12 through 13, you state that FPL has made tremendous improvements in efficiency, reliability, and quality of service while significantly reducing head count. By stating "significantly reducing head count," are you referring to the reduction from 15,000 employees in 1988 to the forecasted 11,111 projected in the 2010 test year?

A. Yes, I am.

Q. Could you tell me when the forecast, the 2011 forecast was made?

Let me restate that. What was the data that was used to make the 2011 forecast or the assumptions?

A. The assumptions in the 2011 forecast were provided by our corporate budget department, and FPL witness Bob Barrett would know more about the assumptions provided across the company? The timing of the 2010 and 2011 development was -- again, it's something Mr. Barrett would know more specifically than I, but it's my understanding we created these forecasts in the fall of 2008.

Q. All right. Do you know why there's a projected increase of 47 employees for 2011?

A. I do not specifically know all the details behind it, because the staffing level forecasts were developed for each business unit by the business unit and loaded into our budget system. I do know that, again, supporting documentation may be available through Mr. Barrett, but that's not my core responsibility.

Q. Okay. Given that these forecasts were made in the fall of 2008, and given the current economic downturn in Florida and the nation, are you still -- is FPL still forecasting this increase in employees?

A. Yes, we are.

Q. Do you know why the projected increase in positions is all in exempt salaried positions, with a decrease in hourly and union employees?

A. No, I do not.

Q. Who should that question be directed to?

A. I believe, again, because the data is gathered by Mr. Barrett, he may have information on, for example, a business unit by business unit basis, and I'm supporting the aggregate increases, although I too have access to a number of interrogatories we provided as a company in response to questions regarding staffing level changes by business unit. So I could either attempt to look it up for you or Mr. Barrett could, but it has gone -- if you could give me a moment to look through the interrogatories.

Q. Yes, please.

(Off the record briefly.)

A. I am looking at an interrogatory response. It is OPC's Second Set of Interrogatories, Question Number 115, where FPL has provided the average staffing levels by employment category for the historic and forecast years. And based on the information provided, it shows that both exempt and union categories of employees are increasing for 2010 and 2011 and that it's only the non-exempt, non-union category of employee that is decreasing slightly.

I do not have any specific information about the drivers of that decrease with me here today, but I would be probably the more appropriate witness to talk to about this than Mr. Barrett.

MS. CLARK: Kathryn, would now be a good place to take a little break?

MS. COWDERY: That would be fine. Well, I've got two little follow-up questions, and then we'll take a break.

MS. CLARK: Okay.

BY MS. COWDERY:

Q. Based on what you just said, Ms. Slattery, the projected positions are not all executive positions, because didn't you say there was an increase in some union?

A. Well, your question just used the term "executive positions," and I was talking exempt positions.

Q. Right. This is a new question.

A. Oh, I'm sorry. If you could please repeat it.

Q. Are the projected -- the positions projected for increase, are they all executive positions?

A. No.

Q. All right. Well, that's what I thought.

And you think Mr. Barrett would be a better person to ask as to why there is a forecast need for more executives?

A. No. No, I would be the appropriate person.

Q. Okay. Why is there a forecast need for more executive positions?

A. I do not believe that we have forecasted an increase in the number of budgeted positions in executive locations. Earlier this morning we talked about my reference to Staff Interrogatory 16 regarding the number of executive positions, and at that time I said that 42 positions are budgeted for 2010, and that number is constant for 2011. There are 42 budgeted positions where the head count and payroll was included in MFR C-35.

Q. Okay. You'll refresh my recollection here. What is the number of executive positions for 2008?

A. We provided compensation data on 44 executive positions in 2008.

Q. So there is a decrease in the number of executive positions forecast, from 44 to 42 from 2008 to 2010?

A. In the budgeted forecast there is.

MS. COWDERY: Okay. This is a fine place for a break, so we might like 5 or 10 minutes. How long would you like?

MS. CLARK: Kathryn, can we do 10 and come back at 20 to 11:00.

MS. COWDERY: That sounds great. Let's do it. We will go off the record.

(Short recess.)

MS. COWDERY: We are going to go back on the record, and I will tell you that Clarence Prestwood is not in the office right now. He's going to join us in a couple of minutes. So why don't we start into me asking some additional questions, and then we can go back and pick up those questions from earlier that you have an answer to. Does that work?

MS. CLARK: Yes, Kathryn.

MS. COWDERY: Okay. Let's do it.

BY MS. COWDERY:

Q. All right. Ms. Slattery, we were talking about your testimony on total compensation. And on page 11, line 23, you refer to, quote, performance-based pay programs, and I would like you to explain that phrase to me.

A. Performance-based pay programs generally refer to incentive compensation programs. However, we also strongly believe here at FPL that our base salary increases our performance base, so any annual merit increase an employee gets or does not get is related to performance and communicated as such. But in general, the most effective tool and the most widely recognized tool in a performance-based pay program is incentive compensation.

Q. Do non-exempt and union employees both receive a portion of their compensation that is variable?

A. Generally, no. I'm not familiar with all the terms of our collective bargaining agreement, which may contain for certain employees certain things like licensing bonuses when certain qualifications are received. But as a general rule, our incentive compensation programs are something for which our salaried employees are eligible.

Q. Okay. Now I'm going to ask you some specific questions concerning the cash compensation programs. Let's see. On page 12 of your testimony, I would like you to please explain how the variable pay is linked to individual objectives. On lines 3 to 6, I'm referring to that testimony.

A. The variable performance-based pay is linked to individual objectives because every employee, non-bargaining employee of Florida Power & Light Company is part of a Partners in Performance, a performance review process whereby key objectives are set out at the beginning of a calendar year, reviewed at midyear, and then assessed at end of year. So every employee has individual goals that they have to meet related to their role and job.

Q. How is the variable pay linked to budget, and what budget are we talking about?

A. Variable pay is budgeted. It's in our budget system, it's in all our forecasts, and it's included in our MFR C-35 figures.

If you could be more specific with your

question, I may be able to answer it.

Q. You say that the variable pay is linked to individual, business unit, and corporate objectives, including budget and financial performance goals, so I want to know how is variable pay linked to individual objectives referencing the budget performance goals.

A. Well, again, I need to start out at the macro level, that the company has O&M and capital expenditure performance targets, and each business unit does as well. Depending on the level of responsibility of the individual within the business unit, they may have very clear line of sight to that.

As an example, an employee in a management role who manages a department will have a budget for that department, and it is generally going to be an enumerated item on their performance objectives that they have to bring their budgets in on target.

As you get further down the line, an individual contributor who may have no budget oversight or responsibility, those individuals may not have direct line of sight to budget targets.

Q. Okay. That makes sense. How is the variable pay linked to individual objectives related to financial performance goals?

A. Again, the fundamental concept is much the same as what I described for budget targets. The higher up in the organization you go, the more clear line of sight there is to the achievement of financial goals. So starting at senior level with management, there would be clear line of sight. Top level business unit leaders will have other financial-related goals. And individuals, as you get further down the chain into individual contributor levels, they're less likely to.

A financial performance goal is something that probably requires definition, because I would assert that bringing your O&M budget in at or below target and your capital expenditure budget in at or below target is, in essence, a financial performance goal that's designed to maximize efficiency and increase productivity to the benefit of our customers.

There are, I'm sure, dozen of other examples of financial goals, including, for example, an individual employee who has a project that they're working on for a calendar year that is expected to achieve a certain amount of return on investment that they need to meet. So this is going to depend person by person throughout the company.

Q. Okay. Following up on that answer, what type of project would involve an expectation of receiving a certain return on investment?

A. Well, that's not an area that I generally work in, so I don't have specific examples. But, for example, I believe that some of our lean engineers in power generation may have certain goals set out for them regarding achieving increased efficiencies in a plant, and that may include targets and also some return on investment or some improvement in efficiency that would be tied to a decrease in cost. So I don't have much in the way of specific examples other than that one.

Another thing is savings for an information management system. I'm sure in information management, where they do kind of a case study before they receive approval for O&M and capital expenditures, that they promise a certain return on investment in the way of increased efficiency, and those folks are expected to deliver on those promises.

Q. Okay. Well, that's very helpful.

So the return on investment goals, who would be setting the return on investment goals in the examples you gave?

A. Well, across our thousands of employees who are part of our Partners in Performance process, all goals are set by the immediate supervisor to the employee, subject to approval by more senior management of that business unit. So I'm sure there is marked variability in the type of performance goals and measures across different departments and business units, and this is handled by the business units themselves, because they know their business. HR simply provides the systems, tools, and support for that performance management system.

Q. So you think the setting of return on investment goals is set on a business unit by business unit basis?

A. I would like to make it clear that when I brought up a return on investment goal, that was one example that came to mind. But, yes, indeed, we're talking about individual goals in this line of questioning, and individual goals are set between the employee and the supervisor and are ultimately at the discretion of the business leadership to approve.

Q. So business unit leaders might be someone also to ask questions regarding that type of performance goal which involves return on investment; is that correct?

A. Yes, although, again, I'm a little uncomfortable with the overemphasis on return on investment as, in essence, in this line of questioning the one and only example of a financial goal. That was, again, just something that came to my mind in regard to the types of projects that our information technology employees may work on or a lean engineer may work on. I'm sure that there are myriad goals related to financial and operating performance that you'll find across an organization as broad as ours.

Q. Okay. Could you please explain how the variable pay linked to individual objectives is also linked to operating efficiency milestones? And again, we're on page 12 of your testimony, lines 2 through 5.

A. Certainly. Again, there will be variability between employees' roles in business units. But there is -- it's just like with the budgeting and financial goals as well. At the corporate level, we have very well disclosed performance objectives, and each business unit in turn has similar performance goals and operating efficiency milestone objectives. And then depending on the level in the organization that the employee is at and the nature of their job, they will have similar goals.

A good example of this is that one of our corporate objectives is customer satisfaction with our residential and business customers as measured by a survey. And in the customer service business unit, there is direct linkage at the top business unit level to these objectives, and I would expect to see kind of a trickle-down of those goals into the key objectives of the majority, if not all, of the employees in that business unit.

Q. Okay. One operating efficiency milestone given is plant availability in line 5 of your testimony. What is plant availability, and how is it measured as an efficiency milestone?

A. Just one moment while I look up our corporate objectives.

I am not an expert on fossil generation or nuclear generation, so I'm not very familiar with their measures, but I do know that plant availability as measured in a fossil generation unit is targeted at best-in-class performance and is something that all of the employees of that business unit have line of sight to. I do not have specific information with me as far as how it's measured.

Q. Can you tell me how it's linked to individual objectives?

A. I do not have specific key objective documents for that business unit with me, but I would expect that for senior leadership of power generation, there would be direct linkage to their responsibility to achieve the target set out for them regarding the fossil plant generation availability, and that as you go down in the organization, there would also be line of sight to that goal for the whole business unit.

Q. Okay. Thank you.

A. But I don't have any with me to look at.

Q. Okay. And another operating efficiency milestone referenced is service reliability. What is service reliability, and how is it measured as an efficiency milestone with regard to the individual objectives?

A. It is my understanding that service reliability is measured based on a number of indicators, including frequency of service interruptions, frequency of momentary interruptions, and there are additional service availability indicators that the power systems group, which is our distribution and transmission and substation business unit, will have in their business unit plans, and they're reflected in their individual performance goals.

Q. Now, the way I framed this last group of questions to you was asking how variable pay linked to individual objectives was affected by certain of these other factors. I would ask you the same questions regarding how variable pay is linked to a business unit objective, but I would first want to you ask you, would there be any difference in your answers?

A. Not substantively. Again, the overarching philosophy is that the lower down in the organization you go, the less line of sight there is to the corporate objectives around plant availability, service reliability, customer service satisfaction ratings and the like. At the business unit level, for a business unit's particular indicators that it's responsible for, you're going to find line of sight to each of these, depending on the business unit.

And again, the further down you go, the more you to have to expect that the low level individual contributor, salaried employee's key objectives for the year are going to be more directly related to his or her job responsibilities at the lower level. The higher up you go, you're going to find more and more line of sight to the overarching corporate objectives regarding providing excellent customer service, reliability, and plant availability to our customers. So at the business unit level, as I just said, you're going to find clear line of sight.

Q. Okay. You state that variable pay is linked to corporate objectives. Could you explain to which corporation you are referring, or corporations?

A. In this sentence, I am referring to the Florida Power & Light Company operating indicators, which we've provided in the interrogatory, which include operations and maintenance costs, capital expenditures, et cetera.

Q. And I did not hear the name of -- did you give an interrogatory number on that?

A. I think, actually, I did not. I know that through production of documents and interrogatory responses we have discussed this. Please hold just one moment. Let me look for that.

I have not been able to identify which specific interrogatory or POD, probably because it's part of a voluminous response to an early POD.

Q. So corporate objectives with relationship to variable pay include O&M costs. And can you think of any other corporate objectives to which you're referring offhand?

A. Yes, I can offhand. It's bringing in O&M costs at or under budget, bringing in capital expenditures at or under budget. There's an income goal, regulatory return on equity. There's a fossil generation plant availability goal, a nuclear industry rating. I think it's a performance index. And there are three separate distribution specific goals related to service unavailability, frequency of service interruptions, and frequency of momentary interruptions, and there is a safety goal tied to the number of OSHA reportables per 200,00 person-hours worked, an environmental impact goal, and two customer satisfaction ratings, one for residential and one for business.

Q. I think we can go back to those questions that I asked earlier in the deposition which you were going to find some additional information on.

MS. CLARK: Kathryn, would you go ahead and ask the questions again so we know we're giving the correct --

MS. COWDERY: I will do my best.

BY MS. COWDERY:

Q. This was referring back to Ms. Slattery's testimony on page 4, lines 21 through 23. The average number of employees forecasted for 2010 is 11,111 broken down between exempt, non-exempt, and union. Our question, I think, was how many of these employees -- let's see. You answered how many of the employees made more than $165,000 total compensation. We were asking what is the percentage of employees that make more than $165,000 in total compensation.

That was the first question. Do you want to address that first before I go on?

A. Yes, certainly. The total number of employees in 2008 whose total compensation was at or above 165,000 was 463 employees, and that would be approximately 4.3

percent of 10,724 employees as shown on the MFR C-35 that we had in 2008.

Q. And that was of how many employees?

A. 463 employees out 10,724 on MFR C-35 is 4.3 percent for 2008.

Q. Okay. And the next question was how many of these employees make more than $200,000 total compensation, and what percentage is that?

A. Making it clear that this is a subset and not in addition to, that would be 269 employees out of the 463, and 269 employees is 2.5 percent of the 10,724 employees for 2008.

MS. COWDERY: Okay. That does answer the question. Thank you very much.

Give me one second.

For the record, Cindy Miller who was here earlier in the room has departed, as has Anna Williams, who is no longer in the room with us?

MS. CLARK: Does that mean we're getting near the end, Kathryn?

MS. COWDERY: Hold on one second. We've got a messenger in the office.

MS. CLARK: Okay.

MS. COWDERY: Okay. We will continue.

It means some people just don't have very much fortitude is what it means.

BY MS. COWDERY:

Q. All right. On page 13 of your testimony, Ms. Slattery, on line 10, you're talking about FPL's cash compensation program compared to market. Could you please define your use of the phrase "cash compensation program"?

A. Yes. Cash compensation consists of -- what we can benchmark is base salary level and annual incentive awards, which we have provided benchmark data on in two separate exhibits to my testimony.

Q. Is this the same as the total awards program?

A. No. We do not generally benchmark certain forms of cash compensation that are not included in the base salary category or the annual incentive compensation category. I do not personally prepare all the market data that we submit. I believe in certain surveys that a component of overtime pay may or may not be included. But in general, we consider this to be our annual base salary and annual cash incentive compensation benchmark?

MS. CLARK: One minute, Kathryn.

MS. COWDERY: Yes.

(Off the record briefly.)

THE WITNESS: I just want to clarify. Did you ask me a question regarding total rewards benchmarking, or did you just want the specific cash compensation benchmarking question answered?

BY MS. COWDERY:

Q. I wanted -- my question was whether the cash compensation program is the same as the total awards program previously referred to in your testimony.

A. No, it is not. Total rewards consist of all components of compensation and benefits.

Q. Because it's the total awards program?

A. Rewards.

Q. And the cash compensation program does not include what that is also in the total awards program?

A. It does not include any of the benefits, nor does it include certain forms of compensation, which in relation to the grand total of compensation is a very small percent, but the benchmark data is not available on.

Q. Do you know what those benchmarks are, or those benefits?

A. If you're asking which forms of compensation are not included in benchmark surveys --

Q. Well, which -- I'm more focusing on the program itself. When you say program, what forms of compensation are not included in that program?

A. Well, all forms of compensation are included in our total rewards budgeting and our total rewards philosophy.

Q. Right. But we're looking at -- like on line 10 on page 13, you're referencing cash compensation program compared to market, so I'm just trying to find out what the difference is between the cash compensation program and your total awards program. It's a subset; right?

A. Yes. I'm sorry. It's a subset.

Q. Okay. And the cash compensation program does not include any benefits?

A. Correct.

Q. And what else doesn't it include?

A. Well, the cash compensation program would also not include equity compensation that's paid in the form of stock.

Q. Okay. Anything that it does not --

A. Well, as a defined term, cash compensation would be all compensation paid in the form of cash, so that would include -- it would exclude benefits, and it would exclude equity compensation.

Q. All right. In talking about your cash compensation program compared to market, you state that the base pay levels are comparable to the rates paid by

FPL competitors. How do you define competitors in that statement?

MS. CLARK: Where are you, Kathryn?

MS. COWDERY: On page 13, line 11.

A. The definition of competitors for employees performing similar jobs and with similar skill sets will vary depending on what that position is. In other words, competitors for a nuclear site reactor operator are different from competitors for a customer service representative in one of our local care centers. And accordingly, when we look at the multiple sources or data we use for our benchmarking, which as referenced in this paragraph of my testimony were 69 for this particular year, the definition of, you know, competitors will vary a little bit. In general, we strive to find similar jobs with similar skill sets with similar companies, or in the case of our non-exempt employees, similar geographic regions.

Q. Okay. On lines 12 through 14, you state you perform a detailed annual benchmarking analysis of your pay rates. Are you referring solely to base pay rates?

A. Yes. In this particular paragraph, I am referring to our base salary benchmarking study.

Q. Okay. If FPL's base pay levels are comparable to the rates paid by its competitors, as you state in your testimony, why is poaching of employees considered a problem by FPL?

A. Well, we're actually quite proud of how prudently we've managed our workforce to try to keep poaching to a minimum, and we definitely believe that our thoughtfully designed total rewards program is our most effective tool in minimizing poaching of our talent. Therefore, it's the total compensation and benefits package and our performance-based pay programs that are our fundamental tool to defend against poaching, and we feel that we've done a very good job of that.

You can't eliminate any and all poaching in the most competitive jobs, but I have no reason to believe that we haven't done as well as or much better than our competitors in designing programs that keep our employees here so that we don't have more costly turnover and our investment in our intellectual capital is protected to the benefit of our customers.

Q. When you were referencing FPL's base pay levels as being comparable to rates paid by its competitors, are you talking about all base pay, the entire range of base pay that FPL compensates its workers, for instance $25,000 to $400,000?

MS. CLARK: Kathryn, let me object to that and ask you to be a little bit more specific.

BY MS. COWDERY:

Q. What is the base pay salary range used to determine the average base pay level referenced in line 11 on page 13 of your testimony?

A. That was a benchmark study that was provided in a production of document request, but I want to stress that when we talk about our aggregate position to market, that's in the aggregate. That's across all positions using all benchmark data.

Naturally, you're going to have particular individuals or positions within the company that are at the top or the bottom of the range. I do not have handy with me what the top and bottom of the range is. I just know and have data here that shows that in the aggregate, as shown on Exhibit KS-2 to my testimony, organization-wide, our non-bargaining employees are right at about median, 1.8 percent below.

Q. On page 13, lines 22 and 23, you state, "For the period from 2006 to 2011 represented on MFR C-35, FPL's compensation or gross payroll expense per employee is forecasted to increase. When you say per employee, are you referring to exempt, non-exempt, and union employees?

A. Yes, all employees.

Q. In your testimony you state that CPI increases have understated national salary increases for many years. Could you please state the basis for that statement?

A. Yes, I can, if you'll please just give me one moment to pull my backup documentation on that.

Q. Certainly.

A. All right. Our sources for that statement are a comparison of the consumer price index to the WorldatWork salary index and the Compensation per Hour (Non-Farm Business Sector) index, which is provided by the same source as CPI, which is the Bureau of Labor Statistics.

Q. Do you believe that the CPI increase for the most recent two or three years understates the national salary increases?

A. Yes. Based on this data from WorldatWork and the Bureau of Labor Statistics' Compensation per Hour (Non-Farm Business Sector), CPI for the past several years has understated compensation increases.

Q. And could you tell me again which data you're looking at or where it is located?

A. We believe this was provided in a late-filed exhibit that was just filed yesterday, which is the backup document for KS-3. So we have provided in table form the total cash compensation per employee WorldatWork salary index and the Compensation per Hour (Non-Farm Business Sector) rates next to CPI. So if you have the late-filed exhibit from yesterday, you have that information.

MS. CLARK: Kathryn, that is what I sent you last night, and I think I got an e-mail from you indicating you got it.

MS. COWDERY: Yes, I do have it right here.

BY MS. COWDERY:

Q. Is that particular document, Ms. Slattery, the two-page document that the first page says "Back-up for Document KS-3, Total Cash Compensation per Employee" with the chart you were just referencing?

A. Yes.

Q. And there's a second page to this particular exhibit, the Compensation per Hour (Non-Farm Business Sector)?

A. Yes. The source of that is the Bureau of Labor Statistics, the same source that produces CPIU.

Q. Okay. The third page was a separate late-filed exhibit, was it not, Total Benefits Costs, 2003 to 2010?

A. Yes. Yes, that's correct. That was a separate exhibit.

MS. COWDERY: We'll go ahead, since we're addressing this at this time, and mark your Back-up for Document KS-3 as Exhibit A.

MS. CLARK: Is it Exhibit A or 1, Kathryn?

MS. COWDERY: Are we using A or 1? We'll use 1.

MS. CLARK: Okay. That's what I'm familiar with. What did you title it? Back-up for Document KS-3.

MS. COWDERY: Yes.

MS. CLARK: Okay.

(Deposition Exhibit Number 1 was marked for identification.)

BY MS. COWDERY:

Q. On page 14, lines 13 through 17, you identify a Compensation per Hour index. Could you please explain what that index is?

A. I'm sorry. Could you please repeat the page number and line number you're looking at?

Q. It is page 14, and line 13 is the portion of the sentence referencing a Compensation per Hour index.

A. It is the Compensation per Hour (Non-Farm Business Sector) wage index published by the Bureau of Labor Statistics, page 2 of Exhibit 1.

Q. Okay. Why do you believe that the

Compensation per Hour index is an appropriate indicator of projected increase in compensation or gross payroll cost per employee?

A. Because CPIU was not designed to be a wage or salary index. It is representational of inflation for a represented basket of goods and services that consumers in an urban household might purchase, whereas the Bureau of Labor Statistics Compensation per Hour (Non-Farm Business Sector) was specifically designed as an index of wage or salary growth. And furthermore, it's my understanding that the Social Security Administration uses the Bureau of Labor Statistics' Compensation per Hour (Non-Farm Business Sector) when considering cost of living increases for those receiving Social Security benefits, which seems to me to be evidence of their acceptance of this index as a more appropriate indicator of wage or salary growth over CPIU.

Q. Do you know when the Compensation per Hour index projection of 18.6 percent was formulated or calculated? And this is referring again to line 13 on page 14 of your direct testimony?

A. Yes. Just one moment while I look at my documentation.

It appears that that information was compiled shortly before we filed our MFRs and testimony in

February of 2009.

Q. Do you know the time period from which the actual data used -- let me start that one over. From what time period are the actual data used which form the underlying assumptions of this projection?

A. I do not know.

MS. CLARK: Kathryn, would you give us a minute, and we'll see if we can locate something?

MS. COWDERY: Certainly.

(Off the record briefly.)

THE WITNESS: The data regarding the Non-Farm Business Sector wage index is published by the Bureau of Labor Statistics, and we used an extract from their system extracted on March 10, 2009. So all information was provided by the Bureau of Labor Statistics as of that date through their website.

BY MS. COWDERY:

Q. We don't know the actual time frame that the data was from at this point?

A. No. We would have to ask them, the Bureau of Labor Statistics.

Q. Do you know when the WorldatWork index's projected growth rate of 17.5 percent was calculated, which you reference in line 17 of your testimony?

MS. CLARK: We're taking a moment to look it up.

A. I do not have the date that WorldatWork provided that to us.

Q. I would like to ask you a question about Deposition Exhibit 1. Do the amounts of total benefits for FPL for each year shown on that exhibit agree with the amounts that are shown in MFR Schedule 35?

A. So you're referring to -- are you referring to page 3 of Deposition Exhibit 1, which I consider to be a separate exhibit regarding benefits.

MS. COWDERY: Actually, I am. I am actually referring to the exhibit we have not yet covered, so we would mark this as Deposition Exhibit 2.

(Deposition Exhibit Number 2 was marked for identification.)

BY MS. COWDERY:

Q. Same question.

A. Yes, it does tie to C-35.

Q. And Deposition Exhibit 2 is a one-page exhibit titled "Total Benefits Costs, 2003 through 2010."

A. Yes.

Q. On page 15 of your direct testimony, Ms. Slattery, in the area of lines 8 through 12, you use the phrase "gross payroll cost." Are you using the phrase "gross payroll cost" to mean the same thing as total compensation cost?

A. No. I am referring to the gross payroll cost that is prescribed as a FERC Form 1 requirement, so that it would be a definition consistent from respondent to respondent to FERC Form 1 requirements.

Q. Am I correct that the phrase "total compensation cost" includes benefits?

A. No. I would say that total compensation and benefits costs includes benefits, and that total compensation cost is a subset thereto.

Q. Okay. Thank you.

MS. CLARK: Kathryn, I need to step out for a minute. Can we just go off the record?

MS. COWDERY: Yes, we certainly can. You want 10 minutes?

MS. CLARK: Yes, please.

MS. COWDERY: Okay. We are off the record.

(Short recess.)

BY MS. COWDERY:

Q. I had asked a question, Ms. Slattery, concerning how variable pay is linked to corporate objectives, and by corporate objectives, to which corporation or corporations were you referring, and your response had to do with FPL operating indicators. I just want to be sure that I understand that when we're talking about corporate objectives, is variable pay to employees linked to any corporate objectives for FPL affiliated corporations, such as FPL Group?

A. My earlier answer was specific as to the paragraph in my testimony we were discussing, but I will make clear that for all the employees below officer level, the corporate objectives to which their variable pay is linked is strictly Florida Power & Light Company. For our officers, there is some component related to the performance of FPL Group to the extent that they contribute to the financial strength of the company that attracts capital for us to invest in our utility, and also to the extent that we want to incent behaviors that are team-oriented and are working towards a common goal. And it also recognizes the fact that Florida Power & Light benefits from some of the intellectual capital developed by affiliates of FPL Group, for example, with regard to solar energy technology and some of our other initiatives related to fuel efficiency.

But again, below the officer level, it's strictly based on the corporate performance of Florida Power & Light Company. At the officer level, there is some recognition of our officers and their contribution towards the strength of the parent company.

Q. And by officers, we're referring to those 44 employees?

A. That's correct.

Q. Okay. Is there any way for us to know how this compensation target is set? I mean, is it a target? Is it a target goal that they're supposed to meet?

MS. CLARK: Kathryn, I think -- target compensation? We're having trouble understanding your question.

MS. COWDERY: I'm trying to figure out how to ask it.

BY MS. COWDERY:

Q. How is this compensation set? How is the variable compensation set which would allow the officers to get a portion of compensation based on the performance of FPL Group? How do you do that?

A. First of all, let me make it clear that the Florida Power & Light Company officers' performance objectives are related to the operating and financial performance of Florida Power & Light Company and not to any affiliate of any other subsidiary. You know, we're really talking about a construct that we use to ensure that there's consideration of the utility's operating performance results, but also that we recognize that a holistic approach to operations means better results to the entire operation.

MS. CLARK: Kathryn, would you ask your question again? I'm wondering if you're asking about process or --

MS. COWDERY: I'm asking how is a compensation level based on performance of FPL Group set.

MS. CLARK: Just a minute.

THE WITNESS: I'm looking through my materials for a moment.

MR. WIGHT: Kathryn, this is Schef Wright. When you are speaking, I am getting a lot of windy static, like noise on a highway or something. I don't know if someone is listening in on a cell phone or if there's just some glitch in the telecommunications, but --

MS. COWDERY: It started raining really, really hard here.

MR. WIGHT: That must be what it is.

MS. COWDERY: Because I'm even having a hard time hearing myself.

MR. WIGHT: Okay. Then we're going to call that an act of God, and I will go back on mute.

MS. COWDERY: Okay. That's what it is.

MR. WIGHT: Thank you, Kathryn.

THE WITNESS: As I was saying before, for our

Florida Power & Light Company officers, you know, we've had some specific discussion, but perhaps this is made most clear in my rebuttal testimony.

BY MS. COWDERY:

Q. Could you please speak up? As I say, we're having a hard time hearing, I guess because of the rain, so our court reporter is having a hard time. So if you could start over, please.

MS. CLARK: Kathryn, she has suggested referring to her rebuttal testimony, and she's looking at that now.

MS. COWDERY: Okay. Well, we'll let her look at that and then carry on.

A. In my rebuttal testimony, on pages 12 through 14, I believe, I address this issue in a way that may make it the easiest to understand. That is in regards to the annual -- we have an annual incentive plan for our top 13 officers of the corporation.

The purpose of that plan is to ensure that we meet certain standards under the Internal Revenue Code, Section 162(m), that governs the deductibility of compensation expense for the corporation. And we want to be as efficient as possible with our expense, and therefore we, of course, want to take the opportunity to ensure the deducibility of all compensation to the extent that we can. Therefore, we have set up an annual incentive plan that covers our top officers to ensure the deductibility of their performance-based annual incentive pay.

And this has been described in my rebuttal testimony starting on page 12, and it explains that for our top 13 officers who are subject to this plan, a financial matrix related to the earnings per share growth and return on equity of FPL Group, Inc., that is considered as part of the financial performance of the company, and therefore the performance of the officers as described therein.

It's very clear on page 13 of my rebuttal testimony that with regard to the 13 people to whom the financial matrix applies, it's both appropriate and it's fundamental to their overall roles within the company to consider some financial metrics in connection with the performance of these individuals.

These indicators not only benefit the shareholders; they also benefit the customers. It's described in detail on page 13 of my rebuttal testimony that it would be detrimental to customers if in fact the company's compensation package did not encourage senior management to keep the company financially strong. As FPL witnesses Avera and Pimentel described in detail in their testimony, a financially strong company has greater access to capital and a lower cost of capital, which in turn benefits customers through a lower cost structure and lower rates.

Q. How does this financial matrix work?

A. The financial matrix, which is disclosed in the company's annual proxy statement to shareholders -- if you could allow me a moment to get to that.

The financial matrix, which, as I said, is described in detail in the company's annual proxy statement, is based on a return on equity and earnings per share growth targets, which are set based on the actual annual results of the S&P 500 utilities index over a three-year period. So the targets are set in advance based on that performance and then assessed at the end of the year, so that if the company outperforms the index measures, the potential annual incentive awards are potentially greater, and if it underperforms, then the opportunity is relatively lower.

Q. And what is the compensation award linked to? Is it that if you outperform, you get a 1 percent bonus or you get a certain dollar amount? How does that work?

A. This matrix is just one component of a number of factors in a very balanced and measured approach to assessing performance. This is not tied to any threshold or specific dollar payout. It is simply one factor that is used to measure performance. It is not used in place of the operating performance measures I described earlier in this deposition, which directly benefit our customers through, you know, efficiency and productivity measures, and reliability and plant availability and customer service measures. However, this is one component that is taken into consideration in conjunction with other financial and operating performance measures.

Q. So there is no specific amount of compensation, either dollar amount, range, or percentage, which one of these 13 employees can get if there is outperformance of the goals? There's nothing specifically linked. It's just like a little box that's checked, yes, you've outperformed?

A. No. Again, there is a relationship between performance on these measures and the assessed level of performance and the opportunity to receive an annual incentive award.

Q. And what is that relationship?

MS. CLARK: Kathryn, can I interrupt? This is Susan. Are you asking if you meet this X amount, you get X amount of dollars? Is that your question?

MS. COWDERY: Something like that, yes, either X amount of dollars, or a range that's looked at, or a percentage bonus, or something. Is there a specific link between those performance standards and specific compensation?

A. No, it is not prescriptive. It's just one of the pieces that is considered. It is important to note that the annual incentive plan which, as I discussed, is largely designed to ensure deductibility of compensation, which is the most efficient use of company dollars, does require us and we do set maximums on awards that may be given under the plan. And similarly, it requires some sort of completely objective standard that would kind of set a minimum.

So the plan does have in it kind of a baseline net income requirement for there to be awards above zero, and it also sets maximums. So there are guideposts that I wanted to make clear but it is not a prescription whereby a certain performance on this financial matrix equals a certain level of payout or a certain amount of payout per person or in the aggregate.

Q. Okay. Thank you. The only other question is, your discussion right now in your rebuttal is with regard to 13 individuals, but we were talking about the 44 officers for whom compensation may be linked to FPL

Group performance. How are those other 44 minus 13 people -- you know, how is their compensation set with relationship to the performance of FPL Group?

A. Well, their annual incentive compensation is not tied to this financial matrix, so below the top 13, the financial matrix is not part of the assessment of performance, but the financial and operating performance of FPL Group is considered as part of the assessment of their performance.

Q. Okay. Can you tell me how it is considered, since it's not considered through the matrix?

A. Yes. Much as I described before, operating performance is generally focused on O&M and capital expenditures, net income, and other financial objectives which are designed to incent employees and officers to maximize efficiency and productivity, bring projects in under budget, and in general be good stewards of the finances of the company. And then performance measures that are related strictly to operating of the company are generally tied to customer service, generation, power delivery, safety, and other environmental factors.

So the design is much the same for these officers below the top 13 as it is for other employees of the company, with the difference being that the performance of FPL Group's operating measures is taken into consideration as one of a number of performance assessments.

Keep in mind that individual performance continues to be an extremely important component of performance assessment for an individual in the determination of an annual incentive award.

Q. Okay. So for these 31 employees who are not covered by the matrix, do they have something in place where there is a minimum and maximum award, such as is used with the folks covered by the matrix?

A. Although not covered under the same formal shareholder-approved plan as the top officers, our annual incentive program guidelines are generally that the minimum is zero, and we do set maximums on awards also.

Q. And what are those maximums?

A. The maximum is generally 200 percent of kind of our baseline communicated awards.

Q. What is a baseline communicated award?

A. It is merely kind of an internal mechanism of communicating across our employee population that a certain percentage of base pay is kind of the baseline. We try not to use the term "expectation" around that baseline because there is no entitlement.

It varies by job. And it is important to note, as I said earlier in this deposition, that the more responsibility a job entails and the more direct impact to the performance of the company and delivery of promises to customers, the larger the component of pay that is variable performance-based pay is, and therefore, that kind of baseline award goes up as you go up in the organization.

Q. What is that percentage with a baseline communicated award for the top 44 employees?

A. It varies by job there as well.

Q. What would be --

A. And I would say that in general -- I can look that up.

Q. Wonderful.

A. Looking at the officer list, the baseline bonus communicated to them, again as kind of a baseline, is as low as 30 percent, and as you move up in levels of responsibility and impact, it goes all the way up to our CEO, but that's not really a fair representation. I mean, his bonus target, which is disclosed in our proxy, is equal to his base salary. But the number that I see here on the list as the most frequent is 40 to 45 percent of salary as the communicated baseline opportunity, with again a maximum being set at 200 percent of that.

Q. And what is the -- is there an average range that you could give us as to what percent is actually awarded, for whatever time period you can give us?

A. That's based on performance, and I haven't studied what the average payout for any particular person or role or department is. I do know that we are fairly careful at setting our aggregate bonus accruals under fair accounting standard guidelines so that the accrual that we are accruing each year as the performance is being delivered and the awards are being earned is based on the historic actual payouts in the aggregate. And based on that, you know, the company's accruals are generally set at a certain level that are based on historic performance. And I haven't broken it down and studied it in much detail, other than knowing the accountants are satisfied that we are following the accounting rules and accruing an appropriate amount based on our expected liabilities.

Q. Okay. To make sure I haven't gone astray in my thinking here, would it be fair to say that the 40 to 45 percent base pay communicated award is in the ballpark of what is actually awarded to the top 44 officers?

A. No. That is again kind of the baseline communication, and the math on which the minimums and maximums would be set, the minimum, of course, being zero. But because FPL's performance has been superior consistently for the last several years, as we would expect, the actual award payouts have been above baseline, and that is in keeping with the performance that we deliver to our customers, and it shows that the program is working as designed. But in all cases, it has been well below the plan maximum.

Q. So it's somewhere between 45 percent and 200 percent?

A. No. I believe you're mixing apples and oranges here.

Q. Okay. Could be.

A. When I said before that the baseline award of a typical officer that's communicated to him or her is probably 45 percent of base pay, I didn't mean -- the 200 percent is 200 percent of that dollar figure. Whatever the baseline award is, the maximum would be two times that, so that would be 90 percent, not 200 percent.

Q. I see. So we would expect that the actual payouts were probably somewhere between 45 and 90 percent, depending on the employee?

A. Yes. And I want to be very clear that it depends on the employee, because individuals in all levels of the organization certainly are subject to earning significantly less than the baseline. That does happen. We're just talking in the aggregate, that payouts have been representational of performance and have been above the baseline, but below the maximum.

MS. COWDERY: If you could give me just one moment, I need to confer.

(Off the record briefly.)

BY MS. COWDERY:

Q. Ms. Slattery, I just want to make sure that I've ended up where I was starting, which was talking about compensation of the top 44 employees specifically related to the performance of FPL Group. So when we moved over to your rebuttal testimony and we started talking about the baseline communicated awards, these awards that we've been talking about with the 40 to 45 percent baseline, are those awards for the top 44 employees in relationship to performance by FPL Group?

A. I did not understand your question. Could you please rephrase it or clarify it?

Q. Do the top 44 employees who have a component of their variable pay based on the performance of FPL Group have a baseline communicated award of 40 to 45 percent for the performance -- you know, related to the performance of FPL Group?

A. No, no. That is not what I'm saying. Their total opportunity is as you've just described it. However, it is always made clear to them that their actual payout will be based on an assessment of the performance not only at the corporate level, but also their business unit and their individual performance. And I'll come back to corporate in a minute, but I just want to make it clear that individual business unit and corporate performance is assessed, and it's part of a determination of the ultimate award amount.

And in regard to the corporate factor, I think that's what you're trying to ask me a question about, and I don't understand.

Q. Right. I've been trying to find out if we can focus on compensation that comes to employees because of performance at the FPL Group level, and that's finding out if we can identify some kind of specific compensation that is allowed for either in a range or a dollar amount that is specifically focusing on FPL Group performance for those top 44 employees.

A. Well, first of all, I want to say that more importantly, our total projected compensation and benefits cost is reasonable and prudent, including specifically our forecasted annual incentive award expense, and that therefore, because it is reasonable and prudent in the aggregate, and because it is a program that is working and has been proven to be working in delivering superior results to our customers, it is not appropriate to try to carve it into pieces which one person may judge more directly benefits customers versus less directly benefits customers. I want to make that perfectly clear.

Q. Certainly, and I understand that position. We just want to know -- if it can be carved out, we would like to know what that carve-out is. Are you telling me -- I mean, is there any kind of carve-out that you can tell me about, performance based on FPL Group -- variable pay based on the performance of FPL Group for the top 44 employees. Is there any carve-out that we can get? Is that information available at all?

A. No. It is not possible to tie a specific dollar amount or percentage to FPL Group performance versus any other performance factor. It is all assessed in the totality and in the aggregate, and I would say it's heavily weighted towards utility-specific performance anyway. But whatever consideration is taken into account regarding the group performance, it's not a specific formula where I can say this dollar amount or this percentage of this role, this person, or this budget is related to the parent company.

Q. Okay. Is there any way to estimate this amount?

A. I've never attempted to estimate it because it is not pertinent.

Q. But are you able to estimate it.

A. I don't believe so, no.

MS. COWDERY: Okay. Thank you. We are going to go back to your direct testimony on page 15, line -- let's see. Actually -- let me see where we are, actually. Hold on. We're deleting some questions.

MS. CLARK: That suits us. We'll wait.

MS. COWDERY: Right. I figured.

We are thinking now would be a good time to take a lunch break and see if we can delete some of these questions that we've discussed I think in quite a bit of detail.

I don't have a real strong feeling about how long a lunch break to take. We don't know if 45 minutes is sufficient or if people need more time than that based on where they are and how they'll get some lunch. Any thoughts?

MS. CLARK: Kathryn, I know Public Counsel and FIPUG noticed this as well. Do they have any idea how long they're going to take?

MR. BECK: I do.

MS. CLARK: Who is that?

MR. BECK: This is Charlie.

MS. CLARK: Oh, hi, Charlie.

MR. BECK: You know, it's always difficult to guess, but I'm guessing about 15 minutes.

MS. COWDERY: Good man.

MS. KAUFMAN: This is Vicki. I would say probably about the same.

MS. CLARK: Kathryn, let me ask Kathleen, since she's the one answering the questions, how long she feels she would like to take as a break.

How about half an hour?

MS. HARTMAN: Let's take 45 minutes.

MS. COWDERY: Yes, we'll start back up at 1:00.

MS. CLARK: Okay. Thank you.

MS. COWDERY: We're off the record.

(Recess from 12:12 to 1:07 p.m.)

MS. COWDERY: All right. This is Catherine Cowdery. We are back on the record.

BY MS. COWDERY:

Q. Ms. Slattery, hello. If you could turn back to your direct testimony on page 15, lines 13 through 16, you refer to your Exhibit KS-4. Could you give a brief explanation -- let me rephrase that. Could you please explain how Exhibit KS-4 shows that FPL continues to be one of the more efficient utilities from a total compensation standpoint?

A. Yes, I can. Exhibit KS-4 was compiled using FERC Form 1 filings from the utilities indicated on the exhibit for the year 2007. The FERC Form 1 has a uniform definition of gross payroll the companies would have had to adhere to. So by taking the total payroll number and dividing it by the total employees on FERC Form 1, we were able to come up with a FERC Form 1 view of total salaries and wages per employee for that year and compare FPL to the other utilities on that basis.

Q. Okay. Exhibit KS-4 states that it shows total salaries and wages. Does this include all compensation of whatever form, such as stock awards, performance-based pay, other awards, or incentive pay or bonuses?

A. For FERC Form 1, the total wages and salaries that is reported is compiled by regulatory accountants for each company. And since I nor my staff prepare that, I could not describe exactly what's in or out of it. I know that the payroll source is the source for Florida Power & Light Company, and I therefore expect this to be a very fair representation of all wages and salaries, all components of pay that an employee receives.

Q. Please explain how Exhibit KS-4 supports your statement, "This efficiency is particularly evident when one looks at total compensation, whether on a per customer, operating revenue, or operating expense basis." This is again referring back to page 15, lines 14 through 16.

A. KS-4 is an exhibit consisting of four pages. Each of the four pages is based on the FERC Form 1 reported total payroll for each company. Page 1 of the exhibit divides that number by the number of employees reported for each company, and page 2 takes that number and divides it by operating revenue, which is -- they're all sourced from FERC Form 1, so the operating revenues is sourced from FERC Form 1, page 114 of FERC Form 1. And KS-4, page 3 of 4, shows the FERC Form 1 reported total payroll divided by the number of customers for each utility, which is also sourced from FERC Form 1 on page 3 of 4. The fourth and final page of Exhibit KS-4 shows the FERC Form 1 reported total salaries and wages divided by operating expenses, which is also sourced from FERC Form 1. So these are apples-to-apples comparisons.

Q. Does that conclude your answer to that question?

A. No. I just wanted to show that on each exhibit, FPL demonstrates efficiency and productivity. As is documented in my testimony, on a per employee basis we're, you know, middle of the pack. But from a per operating revenue, per customer, and per operating expense basis, we are far better than average. And again, it demonstrates the effectiveness and the efficiency of our company.

Q. Has FPL made any comparisons of productivity measurements produced by the U.S. Bureau of Labor?

A. I'm not sure I understand your question. Would you please clarify what you're asking?

Q. Well, the U.S. Bureau of Labor has productivity measurements. Has FPL made any comparisons of employee productivity using those measurements?

If you don't know, you can --

A. I don't know. I don't know.

Q. Has FPL reflected an increase in productivity in its payroll projections included in the MFRs?

A. I don't understand the question.

Q. Let me think. In the payroll projections included in the MFRs, do those projections include a consideration of the increase in productivity?

A. I do not know. I sponsored two MFR's. I'm not familiar with all the details regarding the others.

Q. Sure. If you do not know, that's fine. Do you know who that question would be better directed to?

MS. CLARK: Kathryn, let me see if I'm clear on what you're asking. You're asking in terms of the staffing levels that have been projected, does the estimate of that level somehow take into account productivity improvements?

MS. COWDERY: Yes, that is correct.

A. I do not know. It is possible that FPL witness Barrett may be able to provide more information on that topic.

Q. Thank you. Do you think he would also know about any comparisons of productivity made with the U.S. Bureau of Labor measurements?

A. I do not know. I do know that each business unit decides on the optimal staffing level required to accomplish performance objectives, and that they budget the appropriate staffing, and that Mr. Barrett's organization collections that information. They have more information than I presently have, but I do not know.

Q. Okay. That's fine. On your Exhibit KS-5, there is a comparison to market. How do you define the term "market" as used in that exhibit and also in your testimony on page 16, line 6?

A. The source of this exhibit is WorldatWork. The market comparison is from the total data population. I do not have any additional information other than some indication that there were approximately 2,618 responses from several hundred companies, and I'm not sure how many of them are represented in this comparison.

Q. Okay. On page 16, line 7, concerning annual pay increase program, what is the annual pay increase program?

A. That is the annual merit-based salary program that I referenced earlier in this deposition. That occurs in the first quarter of the calendar year.

Q. The same that is identified on KS-5 as the merit pay program?

A. Yes, it is. And if I could clarify, KS-5 includes not only the annual merit-based salary program, but also the one time per year distribution of variable performance-based pay which occurs during the same time frame, in the first quarter of the year.

Q. Okay. Thank you for that clarification.

So KS-5 is the same as the annual performance-based merit program consisting of the merit award and the incentive pay program?

A. KS-5 has two pages, page 1 of 2 in regard to non-exempt, and the second page is in regard to exempt. And on each page, it shows the base salary program and the variable performance-based program for the two populations, FPL compared to market.

Q. Okay. We're looking at the exhibit for a moment.

Regarding the first page of Exhibit KS-5, can you tell us the projected merit increases in 2009, 2010, and 2011, and where this information is specifically located in the MFRs?

A. Yes, I can. One moment, please.

Q. Thank you.

MS. CLARK: Kathryn, can we go off the record for just a minutes?

MS. COWDERY: Yes, let's go off the record.

(Discussion off the record.)

A. The answer to the question is that in Staff's Eleventh Set of Interrogatories, Question Number 197, we responded with information regarding forecasted annual merit programs for 2009, '10, and '11, and that that information or that data is included in MFR C-35 as a component of the total compensation and benefits increase year over year for '9, '10, and '11. It's a component of it, but it's not the only factor.

Q. But you specifically set that out in the answer to Staff's Eleventh Set of Interrogatories, Interrogatory Number 197?

A. Yes.

Q. Okay. Give us one moment. We're reviewing that interrogatory response.

I am reviewing the response to Staff's Interrogatory Number 197, and it states that budget guidance for annual merit-based pay increases for exempt and non-exempt are 2 percent for 2009, 2010, and 2011. Does that include the variable pay?

A. No, it does not. As stated in the response, variable pay is budgeted by each business unit after corporate guidance, and the variable pay budgets are provided in other interrogatories.

Q. Okay. Would this have been an interrogatory response that you prepared?

A. Yes, this would be an interrogatory response that I -- there were several interrogatories related to -- (inaudible) -- programs. I'm not sure what information you're looking for.

THE REPORTER: I'm sorry. I lost you.

THE WITNESS: I'm sorry. There were numerous interrogatories that I filed related to annual incentive compensation or variable performance-based pay.

BY MS. COWDERY:

Q. Do you think you would be able to identify for us the response that gives the variable pay projections for 2009, 2010, and 2011?

A. Yes. Give us one moment.

Q. Thank you.

(Off the record briefly.)

A. There are a number of interrogatories regarding the variable performance-based pay programs, as I've already mentioned. I think that one that is perhaps one of the easiest to follow is the response to OPC's Seventh Set of Interrogatories, Question Number 338, which lays out the incentive payments as tied to MFR C-35.

Q. And does it give us the percent for those three years concerning variable pay that would sort of match up --

A. That would match up to -- are you looking for tie up to --

Q. KS-5.

A. Exhibit KS-5?

Q. Yes.

A. I have not performed that calculation, because I have a tremendous amount of total compensation and benefits expense information with me, but KS-5 is very specific regarding the relationship between total salaried employee base pay and the total variable performance-based pay budget for those employees, and I do not have that with me today.

Q. Did you say that that information in that form is not in the response to Interrogatory 338 in OPC's Seventh Set?

A. No, not in that form. In OPC's Seventh Set, Interrogatory 338, it provides the total dollars budgeted for the variable incentive compensation, but it does not express it as a percentage of base salaries as KS-5 does.

Q. Do you think that you could perform that calculation?

A. Yes, I could. If you would like for me to perform it now, it may take a few minutes, because I would have to find the source for the total exempt base pay.

Q. I think if we could get that calculation by Monday, it would be fine. Do you think you could do that?

A. Yes, I can.

MS. CLARK: Kathryn, are you going to give it a title?

MS. COWDERY: Why don't we. We'll call it

Depo 3 and -- let's see. I think we're back to KS-5. How about Projected Variable Pay Increases, 2009 to 2010, or 2011, I guess?

MS. CLARK: Projected Variable Pay Increases, 2009, 2010, and 2011, expressed as a percentage?

MS. COWDERY: Yes.

MS. CLARK: Okay. I think we're clear on what you want.

(Late-filed Deposition Exhibit Number 3 was identified for the record.)

BY MS. COWDERY:

Q. All right. On page 16, lines 21 and 22, you identify total benefit costs projected to be about 198 million in 2010 and 232 million in 2011. Why do these projections show that jump from 198 million to 232 million?

A. On a later page in my testimony, the primary driver is the pension plan, which the annual periodic expense for the pension plan must be calculated under standard accounting rules, FAS 87.

Q. And you are saying retention plan; correct?

A. No, pension plan. I'm sorry.

Q. Oh, pension plan.

A. That's the primary driver of the change. Secondarily, increased medical costs are also a factor in the change, which is being driven by escalating medical costs across the country and is a problem that is shared with other utilities and companies as well.

Q. Are these projections for all employees, that is, exempt, non-exempt, and union?

A. Yes.

Q. Okay. Please explain why the projected total benefits cost for 2010, 198 million, is so much higher than the 2006 amount of 133 million.

A. That is before the net periodic expense or annual expense related to the pension plan are calculated under accounting rules, specifically FAS 87, which is a very complicated calculation. And as I understand it, the primary driver in the change is the decrease in the expected return on assets and the actual decline in market value of the assets in the pension plan in 2008.

Our decline in value was in line with others, probably less than most, that other companies experienced because of market changes. And that's the primary driver of the change in the net periodic expense between those years.

Q. Okay. Is the projected percentage increase in average annual total compensation per employee for the projected test years 2010 and 2011 2 percent?

MS. CLARK: Can you repeat the question, Kathryn, slowly?

MS. COWDERY: Yes.

BY MS. COWDERY:

Q. Is the projected percentage increase in average annual total compensation per employee for the projected test years 2010 and 2011 2 percent?

A. No, it is not. As shown on MFR C-35, line 4, the gross average compensation per employee figure is projected to increase from 2009 to 2010 by 3.41 percent per employee. A component of that is the 2 percent annual merit program budgeted across the employee population. But there are other factors that go into creating our compensation budgets as well, and those include forecasted overtime costs and other forms of compensation as well.

So the 2 percent base salary programs are part of the total year over year increase, but MFR C-35 is the correct reference regarding our year over year increase per employee.

Q. Is the 3.41 percent per employee for both 2010 and 2011? Is it the same for each of those years?

A. No. As shown in MFR C-35, for 2011, the per employee increase is 0.87 percent over the 2010 number.

Q. So it was 3.41 percent for 2011?

A. It's 3.41 percent for 2010 and 0.87 percent for 2011. That's from MFR C-35, line 4.

Q. Okay? Given the recent economic downturn in Florida and the nation as a whole, please explain how FPL justified an increase in the overall rate of compensation for the test years 2010 and 2011.

A. Even in a difficult economy, there is still competition for good resources, and we must pay competitively in order to attract, retain, and motivate the performance of our workforce. We have jobs with unique skill sets that require industry experience, able to -- they can make decisions regarding pay packages independent of rational, market-based data and inputs.

And I've demonstrated in my testimony we are constantly monitoring the economic conditions and what's going on in the marketplace, but at this time, we do not have any reason to question the appropriateness of our budgets and forecasts in regard to this matter. We have instead evidence to the contrary, that in our industry and in general industry, companies had pay raises in 2009 and are forecasting them for 2010. And we have provided evidence of this through our production of documents and in the rebuttal testimony of myself and FPL witness Richard Meischeid of Towers Perrin.

Q. Since the filing of your direct testimony in this case, has FPL taken any actions or had discussions concerning employee compensation in response to the economic downturn?

A. FPL has since the filing of my direct testimony continued to monitor through its relationships with third-party compensation consultants what is going on in the competitive marketplace for talent in our industry and in general industry. Based on the information that we have obtained from these parties, including Towers Perrin, WorldatWork, and Watson Wyatt Worldwide, we have not found it necessary to make any changes to our budgets or forecasts. We have instead affirmed the reasonableness and prudence of our proposed increases and of our budgets and forecasts. We must protect the intellectual capital that we have invested in in this company so that we don't lose it to competitors.

Q. Are -- were you complete? Were you finished?

A. Yes.

Q. Are you aware that in Tampa Electric Company's most recent rate case, TECO decided to forgo salary increases for it officers in its 2009 projected test year due to the current economic downturn?

A. Yes, I am aware of that, and I found it to be a very interesting data point, but I cannot comment on the appropriateness of their decision, since I don't know their competitiveness in the marketplace, their position to market, or their overarching compensation and benefits strategy.

I do know that at Florida Power & Light Company, we are constantly monitoring the marketplace, constantly obtaining data and talking to national and international consultants, Watson Wyatt Worldwide being international. And I do not think it's appropriate for me to compare Tampa Electric's decision to forgo salaries for a handful of employees, I would stress, to FPL's decision to take a measured and reasonable market-based approach to determining the appropriate budgets for compensation and benefits.

Q. In light of the current economic recession, has FPL likewise considered freezing executive compensation?

A. At the present time, we have not considered freezing executive compensation because we have no evidence as to the appropriateness of such action. Instead, we are focused on the competitiveness of our total compensation and benefits packages for our officers, because we have to make sure that we avoid costly turnovers and the loss of intellectual capital that we have invested in who have obviously proven that they are delivering results to our customers.

Q. Is it correct that FPL's customer base has decreased over the past several months?

A. I am not an expert in our customer base and do not know what has happened in the past several months.

Q. Not speaking as an expert regarding customer base, but just as an employee with your general knowledge, have you heard that the customer base has decreased over the past several months?

A. No, I had not heard that. I have been very focused on responding to many interrogatory responses and haven't gotten out much.

Q. We're just looking at a couple of questions to see if we've covered them.

Ms. Slattery, over the past three years, what percentage of employees in each year have received bonuses, incentive pay, or stock awards?

A. I believe that I may need to answer those questions separately regarding annual incentive compensation and stock awards, because I have not aggregated the data.

Q. That would be fine.

A. Regarding annual incentive compensation pay, as I've stated before, all of our salaried employees are eligible for awards. And I'll express this as a percentage, that in 2009, approximately 6.4 percent of our eligible employees received no awards. Therefore, 93.6 percent of eligible employees did.

In 2008, 7.6 percent of our eligible employees did not receive an award. Therefore, 92.4 percent did.

And in 2007, 9.4 percent of our eligible employees did not receive an award. Therefore, 90.6 percent did.

Regarding long-term incentive awards, again, all exempt employees or salaried employees are eligible to receive equity compensation under the long-term incentive plan, but it is used much more selectively to recognize the performance of key employees in key roles and to reward them for the impact to performance. So the numbers are much smaller, and rather than as a percentage of eligible -- I don't have that specific information. I could probably just give just kind of a ballpark and say that in total, each of the past three years, I would say fewer than 600 employees have received equity compensation awards. That's a general ballpark based on my recollection.

Q. Okay. That's sufficient.

A. And actually, now that I think about it, it may be closer to 600 to 700. I would say in the ballpark of 600 to 700 at the outside would receive equity compensation, and that's on a per year basis.

Q. I notice for the annual incentive compensation awards, the percentage of eligible employees receiving such awards has gone down from 2007 to 2008 to 2009. Has the recent economic downturn affected the number of employees who have received theses bonuses or compensation?

A. Actually, I believe you have that reversed. The percentage of eligible employees receiving awards has --

Q. Oh, yes, I did.

A. -- gone up by about a percent each year. And that's reflective of the effect that this program has on driving performance. Poor performance is not tolerated in the organization, and those who do not receive an award are given a very clear message about the unacceptability of poor performance. So this is evidence of this program working. The number of people receiving zero awards has decreased each year as we have driven out poor performance. We have less folks in that category each year.

Q. Since the filing of your direct testimony in this case, has FPL taken any actions or had discussions concerning the incentive, bonus, stock awards components of employee compensation packages in response to the economic downturn?

A. Not that I have participated in. I can only answer for myself and my team. In regard to what we've discussed since the filing of my direct testimony, again, through continuous aggressive monitoring of what is going on in our industry and general industry through our multiple third-party sources, we're constantly keeping abreast of what other companies are doing, and there have been no discussions between myself and my compensation staff regarding anything that would contradict the filings that I have made in this case, you know, that we're staying the course.

Our programs have worked as they were designed to work, and our performance proves that, and market competitive data that we have received demonstrates the reasonableness of our total compensation and benefits expense.

Q. What percentage of FPL employees receive overtime pay?

A. One moment, please.

(Off the record briefly.)

A. I do not have anything with me that would provide that data. I have not studied it. Clearly, the Fair Labor Standards Act requires that any non-exempt, non-salaried employee who works overtime be paid for it, so my best indication is that those are the employees that in general are eligible and may be receiving it when they work more than a standard workweek. In addition, the union contract certainly requires it and has some specific requirements around premium pay.

Q. How many and what percentage of FPL employees who earned more than $165,000 in total compensation earned some amount of overtime?

A. One moment while I review my records.

(Off the record briefly.)

MS. CLARK: Kathryn, we think that's going to take a little while. Could we also provide that to you on Monday, and could we identify that as an exhibit?

MS. COWDERY: That is fine. That would be Depo Exhibit 4; is that right?

MS. CLARK: That's what I have. And it would be --

MS. COWDERY: Percent of FPL employees who earn more than $165,000 in total compensation who earn some amount of overtime, or something very similar. It would be how many and what percent.

MS. CLARK: I think we've got it.

(Late-filed Deposition Exhibit Number 4 was identified for the record.)

BY MS. COWDERY:

Q. Over the past two years, has the number of FPL employees decreased because of the recent economic downturn?

A. No, there is no evidence that the number of employees has decreased. It has increased. That's found on MFR C-35.

Q. Does FPL or FPL Group have any plans to outsource or contract out any work currently performed by FPL employees?

A. None that I am aware of, but I am, again, in a role in HR that is not involved in recruiting or staffing.

Q. Who would be the correct person to ask that question to?

A. I have not heard any talk of outsourcing or anything else, but I don't know where those -- those discussions occur at the most senior leadership levels of each business unit, I would imagine, so I would imagine each business unit leader would be responsible for assessing such opportunities or needs in his or her own business unit, and that's a multiple number of witnesses.

Q. Since the filing of your direct testimony in this case, has FPL taken any actions or had discussions concerning staffing issues in response to the economic downturn?

A. None that I'm aware of.

MS. CLARK: Kathryn, I want to object to the form of the question. What do you mean by staffing issues?

MS. COWDERY: I think the witness has answered the question.

MS. CLARK: I want to preserve the objection.

THE WITNESS: And I do want to clarify. As with the previous response, I am not in a position that I would be part of discussions regarding staffing. Those are conversations that occur with other parties and probably involve the senior leadership of each unit.

BY MS. COWDERY:

Q. Since the filing of your direct testimony, have there been any discussions within FPL or FPL Group concerning layoffs or downsizing its workforce in 2009 or 2010?

A. None that I am aware of, but again, I would have to defer to the senior leadership of the company. I have heard nothing of that kind.

Q. A similar question. Does FPL or FPL Group have any plans for decreasing the workforce in Florida?

A. None of which I am aware.

Q. Since the filing of your direct testimony in this case, have there been any discussions among FPL or FPL Group concerning any reorganization within FPL or FPL Group?

A. None of which I am aware.

Q. I have some questions regarding your rebuttal testimony. On page 5, lines 4 through 5, you state in response to OPC witness Brown's testimony that it is not appropriate to analyze the various components of total compensation separately.

However, in your direct testimony, you appear to separately analyze various components of total compensation in order to argue the reasonableness of these components, for example, in Exhibit KS-2 concerning base pay and KS-5 concerning variable pay and base pay. Could you please explain this apparent contradiction?

A. Yes, I can. To the greatest extent possible and wherever possible, we prefer to address and demonstrate the reasonableness of our total compensation and benefits expense in a little pie, if you will. To that extent, as shown in a number of exhibits to my direct testimony, we have attempted to provide this evidence to the Commission on that basis, for example,

Exhibit KS-1 to my direct testimony with the escalation of total payroll and benefit costs against various indices. And furthermore, another exhibit that we talked about in depth today was Exhibit KS-4, which at least attempted to use total compensation as a whole.

But as discussed earlier today, there are limitations on our ability to benchmark the total pie of compensation and benefits, and it forces us to take a look at compensation and benefits separately for benchmarking purposes. It is not the way that we would choose to do it if the resources were available through third-party survey companies, but again, we're forced to purchase the data that we can get, and that generally divides comp from benefits. The means that we have to look at kind of the two halves of the pie separately, look at benefits and determine the reasonableness of it, and the compensation. And by ensuring that both parts are at or below median, we can feel fairly certain that the total compensation and benefits pie is at or below median.

We do it as a sanity check, but again, it's not appropriate to kind of parse the record and say, "Let's look at one slice of the pie," because, for example, if you were to look at only our employee pension plan, it is extremely undervalue, if you will.

It benchmarks very, very low. It must be looked at in conjunction with the total benefits package for it to have any meaning.

And similarly, with total compensation and benefits, we feel it's inappropriate to focus solely on variable performance-based cash compensation, as an example, and ignore the fact that we made a strategic decision over 10 years ago to shift our expense and our focus from non-performance-based benefits to performance-based variable cash compensation so as to deliver superior results to our customers.

You know, dividing up the pie, that should be left to the company, because we know how best to deliver superior performance to our customers through the total rewards philosophy and tools.

Q. Does that complete your answer?

A. Yes.

Q. On that same page, on lines 8 through 10, you state that the strategic emphasis on variable pay rather than fixed salary costs lowers the company's exposure to steadily increasing salary and fringe benefits costs and adds flexibility in recognizing performance.

My question is, how does emphasis on variable pay rather than fixed salary costs lower the company's exposure to steadily increasing salary and fringe benefit costs when your MFRs and exhibits show that salaries and fringe benefit costs increase every year on average?

A. There are a number of reasons. One of the reasons is that retirement benefits are traditionally, and in the case of FPL, based on calculations that are a percentage of base pay. So if you do not strive to kind of control your increases year over year, you have a corresponding increase in the expense related to 401(k) plans and pension plans. And as demonstrated in one of the exhibits to my direct testimony -- I believe it's KS-5 -- FPL has endeavored over the course of the last several years to stay below market in base salary increases.

In addition, one of the biggest burdens that many utilities have is the expense that's hoisted upon it under the FAS rules, Fair Accounting Standards rules, related to FAS 87, expense of the traditional pension plans, and FAS 106, expense related to post-retirement medical and life insurance plans.

And by eliminating post-retirement medical for new hires, we avoided a tremendous amount of cost associated with that. And by shifting from a traditional final average pay plan for our pension plan, which has very expensive FAS 87 costs associated with it, to a much leaner cash balance style plan, we avoided a tremendous amount of expense there as well. So that is how the cost avoidance and steadily escalating cost avoidance works.

Although our pension cost is indeed going up, the impact is much, much less than if we had not had the foresight over ten years ago to make the strategic changes we made. And we see in other companies how burdened they are right now, particularly in light of the 2008 economic impact on their assets.

Accordingly, we are very proud of the decisions we made over ten years ago, which have reduced our pension costs compared to others, our post-retirement benefits costs compared to others, and much more importantly perhaps, by shifting that focus and that expense into performance-based pay programs over the same period, we've been able to demonstrate a culture of continuous improvement and superior performance delivered to our customers. We're very proud of how smart we were and how well it has worked, and the results prove it.

Q. Does that complete your answer?

A. Yes.

Q. Thank you. On page 6, lines 3 and 4 of your rebuttal, you state that the staffing-level forecasts are management's reasonable estimates of what is required to do the work based on optimal staffng levels. You then go on to explain the many real-life factors which have resulted in the hiring process lagging behind expectations. Given this recognition that optimal staffing levels will not be met, why has FPL not lowered its projections of 11,111 employees in 2010 and 11,159 employees in 2011?

A. First of all, I'm confused by your question, because FPL has not acknowledged that optimal staffing levels will never be met. Rather, we've acknowledged that sometimes we're challenged to find the right talent in the marketplace.

There is turnover that is constantly being backfilled in this company, but no matter what, we still have to get the job done. The work still has to be performed, and what ends up happening is that the employees in departments and business units where the vacancies are being filled have to pick up the slack, working overtime, which we have to pay for.

In addition, this burden on the workforce can hamper productivity, since employees are sometimes dealing with less than optimal work-life balance issues while we're attempting to fill the vacancies. In addition, in some business units, in order to get the work done so we can deliver on our promises to customers, we're forced to use temporary help or temporary contractor labor while we're trying to fill the vacancies.

Q. Okay. Thank you. I'm just reviewing your testimony to make sure I understood what you stated. If you'll give me just one second here.

When you state on lines 11 and 12 that certain factors have historically resulted in the hiring process lagging slightly behind expectations, are you stating that -- what are you stating? Would you please explain that statement?

A. There are a number of factors that would impact the speed at which we can fill a vacancy.

Q. But those vacancies would still be filled? Is that what you're saying?

A. Yes. As the sentence states, it's lagging. We're trying to fill it, and it's lagging.

The most important factor is the unique skills and experience required for the majority of our jobs. You know, we use the example of our Nuclear Division quite frequently in this regard, but there are also unique skills and experience required in all of our line functions, including power generation, transmission, substation, and distribution. So when you have a situation where you're looking for a unique skill set and experience level, and it's in an industry with an aging workforce, as demonstrated in my direct testimony, you have a situation where supply and demand are sometimes working against you, and that's why it can take longer to fill a vacancy.

In addition, there are certain geographic issues that we contend with. For example, it is sometimes difficult to convince nuclear industry workers to go to work at our Turkey Point location in Homestead.

And often the housing market, when we're hiring from around the nation, the housing market in their home state and the area that we're asking them to move to plays a role in the decision on whether or not to take the job.

So there are a number of factors, and these are just a few examples of them.

Q. So when you're talking again about the hiring process lagging slightly behind expectations, does that lag result in positions not being filled during the year for which those projections were made? Is it that long of a lag?

A. I do not know. I cannot say for sure, since these vacancies and recruiting processes are occurring across all business units in a very large company. I do not work in the staffing function, so I'm sure I wouldn't have insight into how long it takes to fill a vacancy in any particular unit.

Q. Okay. On page 7, on lines 3 to 4, you say that market conditions and workforce demographic factors, as you were discussing, have caused the company to fall slightly short of its staffing goals. What do you mean when you say that it falls slightly short of its staffing goals?

A. Just as I described before, that we expect to have the optimal staffing level in our organization, but because of, you know, the turnover and the unique nature of our jobs, it sometimes lags, and at any given point in time we may be slightly short of our goal. But the work still has to be done, and so we end up either using overtime, contractors, or temporary labor to fill the holes.

Q. Well, if your staffing goals are not met, wouldn't this lower the projected number of employees for 2009, 2010, and 1011 from what is currently projected?

A. It could, but that would not lower our costs, because as I stated already, our budgets are based on what it takes to get the work done to deliver on our commitments to our customers, and that work still has to get done.

Q. On page 8, lines 9 through 11, you state that FPL's business unit leaders have developed reliable methods to determine the work hours they need to continue reliable performance for customers. Do you know what those reliable methods for determining work hours are?

A. No, because every business unit is different.

Q. On page 9, line 13, you refer to the market being stressed by skills shortages. In the current economy with a high unemployment rate, do you still maintain that FPL faces a skills shortage?

A. Yes, I do, because unfortunately, FPL cannot utilize laid-off workers from other industries for the majority, the overwhelming majority of its jobs. We need utility industry workers with the proper skill sets and experience to fill our jobs. And as discussed in my direct testimony, there is a shortage of skilled workers in our industry that has been well documented. There are numerous articles and publications quoted in my direct testimony on that shortage, and that situation has not changed in our industry in spite of the economic downturn.

Q. Are you aware of any electric employees which have been laid off in the Southeast?

A. Yes, there have been some employees within the industry laid off, but -- and I'm not a staffing or recruiting specialist for our company, but I, for example, know that none of them were nuclear division workers. And I'm fairly certain that when there have been reductions in force, it has probably been in areas where those are no longer in demand. I can't say for sure that we haven't picked up any of that talent. We may have.

But it does not fundamentally change the supply and demand equation in our industry, and it does not change our staffing model and what we need to pay to be competitive to attract, retain, and motivate our workers.

Q. But you do not have specific knowledge concerning actual staffing at FPL?

MS. CLARK: Let me object to the question and ask you to be more specific.

BY MS. COWDERY:

Q. Ms. Slattery, do you have -- is it correct, Ms. Slattery, that your position does not include having specific knowledge concerning hiring procedures and staffing requirements for FPL business units?

A. Yes, that is correct.

Q. On page 10 of your rebuttal, lines 14 through

17, you state that where FPL's management and employees succeed in increasing fuel efficiency, bringing capital projects in at or under budget, improving productivity, or otherwise controlling costs, the company's customers directly benefit. Could you tell me how these actions directly benefit FPL's customers?

A. I believe that the sentence fairly well speaks for itself and that it's obvious how these would benefit customers. They benefit customers by lowering rates in the long run and through, you know, prudent investment in our infrastructure and in fuel efficiency. And by increasing productivity and improving efficiency, we will directly benefit our customers and lower their rates, while delivering superior service.

MS. COWDERY: If you will give us one minute here, we're slashing through some of these questions because we've had them covered, so let us continue to look here.

(Off the record briefly.)

MS. COWDERY: We have no more questions. Thank you very much, Ms. Slattery.

THE WITNESS: Thank you.

MR. KAUFMAN: Susan, do you want me to go next? Charlie, do you want to go next, or Schef?

MR. BECK: Vicki, if you could go next, that would be great. I wonder if we need to take a break.

MS. CLARK: Charlie, that sounds like a good idea. Should we come back at 25 till?

MR. BECK: That sounds good.

MS. COWDERY: A 10-minute break sounds good, so we will go off the record.

(Short recess.)

CROSS-EXAMINATION

BY MR. KAUFMAN:

Q. Good afternoon, Ms. Slattery. We've had a long day so far. I'm Vicki Kaufman, and I represent the Florida Industrial Power Users Group in this case. I won't go over with you all the conventions that Ms. Cowdery already did, but, of course, if you can't hear me or understand what I'm saying at any time, please let me know.

I really only have a few questions for you after Ms. Cowdery's questions this morning and this afternoon. Hopefully, it won't take too long. And most of them are clarifications to some of the things you told her.

But before that, would you take a look at your rebuttal testimony at page 2, beginning at line 13? If you would let me know when you get there?

A. Yes, I'm there.

Q. And in that paragraph beginning on line 13, you say that the only witness that takes issue with any aspect of FPL's compensation and benefits plan is OPC witness Brown, and you go on to discuss Ms. Brown's testimony.

You don't mean to imply there, do you, that the other intervenors agree with the compensation and benefits package that FPL has put forth in this case?

A. I don't know. I'm not aware of any specific testimony from any intervenor other than OPC witness Brown that did take issue with it.

Q. Have you reviewed the -- well, I guess the Prehearing Order has not come out yet. So you're not aware of the positions of the other intervenors on these issues?

A. No, not yet.

Q. Ms. Cowdery toward the end of her questioning was talking to you about the long-term incentives, and I believe that you said that all salaried employees are eligible for long-term incentives; is that right?

A. It is true that any salaried employee is eligible to receive a long-term incentive award. But as I said earlier, a very small percentage of them actually do.

Q. And that's where I was going. I think you told us that, for example -- you said in 2009, 2008, and 2007, less than -- between 600 and 700 employees received long-term incentives; is that right?

A. That's correct.

Q. And that is out of how many employees?

A. That is out of staffing levels -- (inaudible).

Q. Can you speak up a little bit?

MS. CLARK: She is looking for a document. That's why her voice is fading. Just give us a second, Vicki.

MS. COWDERY: Yes. Our court reporter could not catch that.

A. Okay. The exempt staffing level -- and this is from OPC's Second Set of Interrogatories, Interrogatory Number 115. The number of salaried employees on average in the company is -- for 2009 is 4,819. For 2008, it's 4,641.

Q. Could you just go a little slower if you wouldn't mind?

A. Oh, I'm sorry. I'll repeat myself. For 2009, the average exempt staffing level is 4,819; for 2008, it is 4,641; and for 2007, it was 4,526.

Q. You talked at some length at various times in this deposition about what FPL terms its total rewards package, and I understand the company's position to be that it's inappropriate to look at the individual components of the package, is that right, that you prefer that the Commission simply look at the total of the compensation and benefits package?

A. I would more accurately reflect my position as it cannot be properly evaluated by looking at the individual components without looking at the total compensation and benefits expense, because of the philosophy that I described in a number of answers to questions today.

Q. Let me just use an example, if I could, or a hypothetical. To the extent that an executive benefits and compensation package is composed of a salary -- I think you called it base salary, stock options, incentive compensation based on performance, medical benefits, you are not saying that it is inappropriate for the Commission to look at those individual components, are you?

A. No, I'm not saying it's inappropriate to look at them. I'm saying they can only be properly evaluated When you consider the overarching philosophy that FPL has regarding total compensation and benefits. Going back to the important strategy that we developed over 10 years ago, which is to reduce the expense of our benefits program and to reduce the focus on our benefits program in favor of increased focus on variable performance-based pay to drive the performance of this company and deliver results to customers. By ignoring that change and the under value benefits package, you ignore an important component of our total rewards philosophy.

Q. I appreciate that. I think that your position is clear. And I guess what I'm trying to ask you is, certainly the Commission -- let me restate that. Certainly it's not your position that the Commission is precluded, for example, from reviewing the reasonableness of, say, the executive incentive compensation on a stand-alone basis?

A. Certainly the Commission can look at this or any other component or issue that it wants to, but I'm suggesting that the total value delivered to the employee and the total value to the company should be analyzed on a total compensation and benefits basis.

Q. You had some discussion, I think it was this morning, with Ms. Cowdery about executives that are making more than $165,000. Do you recall that?

A. Yes, but I would not characterize them all as executives. For point of clarification, that list is comprised of some executives or officers and some non-officers, but it was a list of 463 employees in total.

Q. Do you use the term "executives" and "officers" interchangeably? Is that the same thing?

A. Yes, I do.

Q. Okay. And I think you told Ms. Cowdery that for 2008, out of the 463 employees earning more than 165,000, 44 of them were executives. And you use that to mean officers as well; correct?

A. That is correct.

Q. Now, you had a lot of discussion with Ms. Cowdery about your references in your testimony to compensation being linked to attainment of corporate goals, and that's what I want to try and understand. First of all, is it correct that as to these 44 officers, of all the employees of FPL, these are the only employees for whom any part of compensation is linked to the performance of FPL Group?

A. Yes, to my knowledge, that is correct.

Q. Now, of those 44 employees, I think Ms. Cowdery asked you if there was a way to provide information as to what portion or percentage of their compensation related to FPL Group and what percentage related to FPL, the regulated utility; correct?

A. Yes. And to be clear, when we talk about compensation, I'm referencing annual incentive compensation.

Q. Well, for clarity, I'm referencing the total compensation package, or the total rewards, as you call it.

A. And could you please repeat the question?

Q. Yes. I believe that Ms. Cowdery asked you as to these 44 executives that have some portion of their compensation dependent on the performance of FPL Group, that you could not segregate what percentage of their compensation that was. For example, you couldn't say it was 10 percent, 75 percent. You just don't know; is that right?

A. That's correct, because there is, first of all, an assessment of performance that takes into consideration the individual performance of the officer in delivering results, and if it's a business unit leader, the performance of his or her business unit within the company. And those are important components of assessing that individual's performance and determining an appropriate annual incentive award. So in the first place, it's difficult to kind of compartmentalize corporate performance as a separate and stand-alone issue and calculate that percentage.

And then, as I mentioned earlier today, the performance of FPL Group from an operating perspective is taken into consideration, but it's not strictly formulaic or prescribed. And then in addition, we must take into account the fact that for our FPL Group officers, a portion of their pay, including a portion of their annual incentive award, is charged out of the utility or allocated back to FPL Group affiliates, which means that a portion of their pay is borne by other companies to begin with.

So all of these factors together make it extremely difficult or impossible for me to WAG a number that's a percentage.

Q. Now, the 44 employees who some part of their compensation depends on FPL Group, when their incentive compensation is looked it, is part of the amount attributable to the earnings per share of FPL Group? In other words, if the stock price of the parent rises, does that impact their compensation?

A. That is not true for the 44 officers in question. But for the top 13 officers of the company to whom the financial matrix disclosed in our annual proxy statement applies, the growth in earnings per share is one factor we consider in the assessment of overall performance of the company.

Q. Okay. So the earnings per share of the parent company has bearing only on the top 13 executives?

A. That is correct.

Q. Well, for the remaining 39 -- no, my math is not correct. Thirteen from 44. For the remaining executives for whom earnings per share is not part of their review, what goals related to FPL Group are considered in evaluating their compensation?

A. Those goals will vary by officer, but are again tied to individual performance, business unit performance if it's an officer who --

Q. Hold on. I can't hear you.

A. I'll repeat myself. For the remaining officers, individual performance and leadership behaviors, and the performance of --

Q. As it pertains to FPL Group?

A. No. I'm sorry. And the performance of his or her Florida Power & Light business unit. Those are the important components of the performance assessment.

But as far as the corporate level performance indicators, they are disclosed in our annual proxy statement, and I've enumerated them before.

Q. I appreciate that. It's just been a long day.

The 31 --

THE REPORTER: I'm sorry. Ms. Slattery, is there any way you could move closer to the phone?

I'm really struggling here.

THE WITNESS: I'm sorry. I'll talk louder.

Could you please repeat the question that we're on?

BY MR. KAUFMAN:

Q. Yes, I'll try. The 31 top executives which exclude the top 13, if I did my math correctly, a portion of their performance is dependent on the corporate goals -- a portion of their compensation, excuse me, is dependent upon the corporate goals of FPL Group; correct?

A. That's one factor that's considered, but it's not formulaic, and your question kind of insinuates that it is. So I just want to say that it is a factor that is considered in the assessment of performance in the totality, which, as I keep stressing, is largely based on individual and FPL business unit performance too. The corporate goals are assessed for Florida Power & Light Company, for Florida Power & Light Company specific officers, and then Group performance is considered for Florida Power & Light Company officers as kind of a component of overall corporate performance.

For our Group officers, the weighting is 50-50 as far as the performance of FPL and other subsidiaries. But as I mentioned before, a portion of their bonus is also allocated out and charged to the affiliates, as one would expect. But all of this is determined in the totality. You know, it's not purely formulaic. We can't just say that because the operating performance of Florida Power & Light Company is strong that an executive who personally misses targets on projects or whose leadership behaviors are not what we desire is going to receive an award that's exactly equal to some measure of what we consider Florida Power & Light Company's performance to be. It's assessed at the leadership level based on all these factors.

Q. You just mentioned a 50-50. Can you explain what you were referring to, 50-50 split?

A. I'm not sure. Could you please be more specific with the question?

Q. Well, I thought when I just asked you the question about what portion of FPL Group's goals related to the compensation of these 31 employees, I thought that I heard you say that there was some kind of a 50-50 look. Did I mishear you? Or maybe you can explain to me what you meant.

A. For the employees of FPL Group, which are just a handful of our officers -- there are no other employees of FPL Group.

Q. That's the top 13 we talked about; right?

A. No, it's not. It's probably -- I think there may be 12 total, 12 Group employees. The operating performance for Florida Power & Light Company and other affiliates of FPL Group are all considered in determining the appropriate corporate performance assessment to factor into the individual officer's annual incentive review. Again, individual performance is extremely important in determining the total award.

Q. And just so I'm clear, the other either 31 or 32 executives whose performance is tied, at least in some way or partially to FPL Group's goals, you can't really articulate with any specificity how that evaluation is made? It's not formulaic, I understand, but is it sort of a global look?

A. I think I've answered this question. Let me try again.

Q. And I appreciate that you have. I'm just trying to understand the relationship between folks whose compensation is partly related to the goals of FPL Group, and I keep hearing you talk about FPL, the regulated utility, and that's the interplay that I'm trying to understand.

A. For our Florida Power & Light Company officers, when senior leadership reviews the performance of each officer and determines an appropriate award, the corporate performance that is considered is heavily weighted towards Florida Power & Light Company, but the performance of FPL Group from a financial and operating perspective, which doesn't take into consideration, therefore, the contributions to that performance of all affiliates, is considered. It is a very small part of the consideration, and overwhelming, Florida Power & Light Company's operating performance, which is very customer driven, is the overwhelming determinate and starting point for determining an appropriate award.

There is marked variability in individual officer's awards based on their individual contributions to the success of Florida Power & Light Company and the success of their business unit that year, and I've seen very significant upside and downside adjustments based on that individual's performance, so I cannot come up with a clear definition of 5 percent of their award may be based on FPL Group or anything along those lines.

It is important to note that the utility customers benefit by the assembly of a team of talented executives that are all accessing the enterprise, including the technology that we benefit from in the utility from certain affiliates' expertise in solar and wind energy, to the extent that we follow the FERC rules of conduct.

Q. Do you know how many affiliated companies FPL Group --

MS. CLARK: Vicki, this is Susan. She wasn't quite finished.

MR. KAUFMAN: I'm sorry. I thought that you were done. I apologize.

MS. CLARK: It's getting late, so her voice tends to trail off. We'll try to do better.

BY MR. KAUFMAN:

Q. Go ahead, Ms. Slattery, if you weren't finished.

A. I was just saying that there are tangible benefits to our customers from the team philosophy and approach we take, and in addition, it incents the proper leadership behaviors and team philosophy that we want in our company's culture. And I'm finished.

Q. What was the last thing you said?

A. I'm finished. Sorry. My voice is really weakening.

Q. Yes, I can understand that.

Do you know how many affiliated companies are under the FPL Group umbrella?

A. No, I do not know that.

Q. Are you familiar with the Commission's decision in the Tampa Electric case on this question of incentive compensation related to the parent corporation?

MS. CLARK: Vicki, I'm going to object to the form of the question.

MR. KAUFMAN: You can answer, Ms. Slattery.

MS. CLARK: Could you be more specific?

BY MR. KAUFMAN:

Q. Well, you're aware that Tampa Electric recently had a rate case, are you not?

A. Yes, I am.

Q. And are you aware that one of the issues in that case related to executive compensation, related to compensation based on the performance of the parent company?

A. Yes, I am.

Q. And are you aware of the Commission's decision on that issue?

A. Yes, I am.

Q. And they -- well, why don't you tell us what your understanding of that decision was, in layman's terms?

A. I believe that I only know a part of the story, because I'm not aware of the Commission determining the reasonableness or prudence of the compensation and benefits expense or the level of pay that Tampa Electric was delivering to its executives in their effort to retain and motivate their workforce. I am only aware that a small amount of compensation was disallowed, and it had something to do with their executives' incentive compensation pay.

Q. Well, since you, I guess, have been unable to tell us what the -- I'll just call it a split for lack of a better word, understanding that it's not a formulaic approach -- of these 44 employees relate to the performance of FPL Group, if the Commission were to make a disallowance, how would you figure that out?

A. It wouldn't be appropriate to figure it out, because it doesn't change the fact that our program is reasonable and prudent and a necessary expense in delivering the goals to our customers.

Q. I understand that's your position. I want you to assume that the Commission decides as to that portion of the 44 employees' salaries and compensation that relates to FPL Group, we're going to disallow that, we don't think retail ratepayers should bear that cost, how would you determine what should be disallowed?

A. I don't know how I would determine that.

MR. KAUFMAN: Okay. I'm just flipping through.

Thanks Ms. Slattery. That's all I have.

MR. BECK: Susan, this is Charlie. I'm going to ask if Schef could go first before me.

MS. CLARK: Well, Charlie, you know, I'm okay with that as long as Schef doesn't take more than 15 minutes.

MR. BECK: Well, let's see where it goes.

MS. CLARK: I mean, we've been at this a long time. I actually don't have confirmation about an agreement that if it's not noted, that people would be allowed to ask questions. I'm okay with 15 minutes.

CROSS-EXAMINATION

BY MR. WRIGHT:

Q. Okay. Here we go. Good afternoon, Kathleen. We've known each other for about 20 years, I think. It's nice to talk with you again.

A. It's nice to talk to you too, Schef.

MS. CLARK: Schef, will you go ahead and identify yourself and who you're with? You may have done that at the beginning, but --

MR. WRIGHT: I did, but I certainly will. I'm Robert Scheffel Wright. I'm a partner in the law firm of Young van Assenderp in Tallahassee, and in this proceeding, I represent the Florida Retail Federation, on whose behalf I will be asking

Ms. Slattery some questions.

MS. CLARK: Thank you.

BY MR. WRIGHT:

Q. Okay. I'm going to follow on some questions that Ms. Cowdery asked you this morning and also some questions that Ms. Kaufman was just asking you about.

This morning in responding to some questions by Ms. Cowdery, I believe you listed several factors, customer service, reliability, and customer satisfaction, and that these factors are taken into consideration in determining incentive compensation. Is that approximately correct as far as it goes?

A. Yes, I believe so.

Q. Are there any other factors along those lines specifically relating to customer service, reliability, customer satisfaction, and the like, besides those that would be included there?

MS. CLARK: Schef, this is Susan. Could I just object to the question? Can we get more specific as to what you are referring to? I mean, is this is response to -- is this a follow-on to the questions on her testimony? I recall some lines of testimony that she referred Kathleen to.

MR. WRIGHT: Susan, what my notes indicate is that at about 9:34 a.m., Ms. Kathryn Cowdery asked her about what factors are taken into consideration in determining the annual incentive compensation. And I can remove the predicate of Kathryn's questioning and just ask this question.

BY MR. WRIGHT:

Q. Are factors such as customer services, reliability, and customer satisfaction taken into account in determining what I believe you called annual incentive compensation?

A. Yes, and I can assure you that customer service focused goals are demonstrated throughout our business units' annual objectives that are set in advance of each year and in our individual employees' objectivs. We are encouraged to have customer focused performance metrics at all levels of the organization.

Q. Can you give some examples of exactly what those metrics are?

A. Yes, I can. The customer service business has a significant number of customer focused operating objectives that I have seen shared with me by that business unit. And it, of course, trickles down to every employee in that business unit.

This is obviously an easy example, but I would also argue that beyond the obvious example of customer satisfaction as demonstrated through surveys and other customer service specific metrics that, in essence, the overwhelming majority of all of our performance objectives at an individual, business unit, and corporate level are focused on the customer, because they're all about increasing efficiency, improving productivity, to ensure that we have the lowest rates possible. And obviously, we have proven that we have succeeded in that regard, since we have the lowest rates in the state.

Q. Following directly on that, is it an FPL or FPL Group corporate goal to provide safe, adequate, and reliable service at the lowest possible cost that would cover prudent costs and provide sufficient return to attract the necessary capital?

A. I don't understand. I mean, that all sounded good, but I think I would have to break it down. And furthermore, I wouldn't want to have to kind of put words into my senior leadership's mouth as specific as that. I know that I have evidence and can demonstrate that safety and environmental considerations are taken into account when setting our individual, business unit, and corporate objectives.

But there was a whole lot going on in that question, so if you could please rephrase it or break it down for me, that might be helpful.

Q. Let me ask a very direct question. Other things equal, if FPL's management were to lower customer rates, would their compensation, their incentive compensation increase?

MS. CLARK: I'm going to object to that question.

MR. WRIGHT: Are you instructing her not to answer it?

MS. CLARK: No, I'm not. She's going to answer it.

A. I'm going to answer it. No. There is no specific performance goal of which I'm aware that ties executive compensation to lowering of rates. However, I am aware of numerous performance goals that incent our executives to make prudent investments to benefit our customers in the long term by investing prudently in our infrastructure so that we can provide them with fuel efficient, very efficient, environmentally effective or less impactful, reliable and safe service over the long haul at low, affordable rates.

Q. I'm going to ask a similar question. Other things being equal, do higher FLP profits or higher FPL Group profits generally produce higher compensation for FPL executives?

MS. CLARK: And I'll object to the question.

A. I actually didn't hear all of that. Could you please repeat it?

Q. Sure. Other things being equal, if FPL, the utility company, and/or FPL Group, were to realize higher profits, would that result in higher incentive compensation to FPL's executives?

A. There is not a direct relationship between higher profits equaling higher incentives. However, net income is one of the financial objectives of Florida Power & Light Company, but that is to drive efficiency and productivity in the organization, not simply to increase profits. And --

Q. Is there a specific net income goal from year to year? I'm not asking you what it is.

MS. CLARK: Schef, she didn't finish her answer.

MR. WRIGHT: I am sorry. I thought she had.

A. That's okay. I can answer both your new question and continue. There is a specific net income goal each year. It is a very small percentage of the total basket of performance indicators, as I call it. It is not weighted very heavily. It is one goal among a number of them regarding providing dependable, safe, reliable service to our customers.

Q. You just said it's not weighted heavily. It does have a percentage weight attached to it?

A. I am not aware of what the current weighting is. I do believe that last year it may have been about 10 percent of what we considered at the corporate level, at the most.

Q. Okay. And just to make sure I understood your previous answer, am I correct that there's not a specific percentage weighting attached to lower rates in that basket?

A. Again, rates are not something that's specifically tied to our annual incentive plan.

Q. Thank you. In response to a previous question about customer service and reliability, you referred to assessing customer satisfaction through surveys. What sort of surveys do you rely on for that purpose?

A. FPL witness Marlene Santos would have more information than I, but it's my understanding that a J.D. Power and Associates survey of customers is utilized to ascertain customer satisfaction scores from a residential perspective and a business perspective.

Q. Thank you.

A. That is subject to check. That's just my understanding. Marlene Santos would know more than I.

Q. Thank you. We had a lot of talk over the last couple of days and again today about FPL employees who make total compensation of $165,000 a year. I think I just have a couple of questions about that. Are these folks mostly folks who would have job titles like manager, director, or assistant director?

MS. CLARK: Schef, I believe at this point, I would prefer her not to answer that, because it may venture into information we consider confidential.

BY MR. WRIGHT:

Q. Okay. I have a similar question. I'm trying to understand how the $165,000 a year might compare to somebody else in the general economy who had a different compensation package. As a reasonable approximation, if someone had a base salary, including a bonus, if there was one, of something like 125 or $130,000 a year, when you added on health insurance, retirement contribution, et cetera, would that work out to something in the range of $165,000 a year?

MS. CLARK: Schef, would you ask that again? I'm sorry. It is kind of late, and I --

BY MR. WRIGHT:

Q. I'm just trying to get a frame of reference relative to other folks. FPL has a somewhat complex compensation system with, you know, this incentive award and that incentive award, long-term incentive award, and so on, and I'm just trying to put the $165,000 into a frame reference for a total compensation, where if somebody makes something like 125 or $130,000 a year, would that equate out when you added on health insurance, a retirement contribution, dental insurance, and other benefits, would that come pretty close to $165,000 a year?

MS. CLARK: Schef, give us just a minute.

(Off the record briefly.)

A. Regarding the question, first of all, I want to make it clear that when we talk about the list of individuals or the number or percentage of individuals in the range of $165,000 and above, we were talking about total compensation, not just people whose base salaries are in that range. That was the total --

Q. I understand that, and that's why I was trying to figure how that total compensation package would relate to somebody who worked in a managerial position at Target or something like that, just relative to a base salary?

A. Well, first of all, I would object to comparing the manager of a Target store to somebody who has advanced degrees in nuclear engineering and special licensing and 20 years of experience in an industry with a shortage of labor. So you can't compare an apple to an orange. That I want to say right off the bat.

And if you're interested in me speculating on what benefits costs add to the compensation package, I would prefer to rely on the data that we've provided on MFR C-35, showing the approximate cost of fringe benefits when you add them to compensation.

Q. Would it be reasonable to believe that a total benefit adder of something like 20 or 25 percent against base salary would be a reasonable number for folks in that salary range, 100 to $150,000 a year?

A. No, I definitely can't speculate on that. Rather, instead, I just looked at the average per employee costs, and they seem to be much lower than 25 percent, I believe. I don't want to speculate. I don't want to speculate.

Q. Okay. When you compare your officers' total compensation packages, to whom or to what groups do you compare them?

A. The officers' compensation is benchmarked using a survey that has data from a number of comparably sized utilities in our industry with similar business models and complexity. There's a list of companies that we use to benchmark officer data that we publish in our proxy each year, and I can run down the list for you.

But in addition to that, we do find it necessary to look at some general industry comparators for officer data, because we do not simply recruit from or lose talent to utilities, particularly in our staff groups. So there's also general industry companies that we compare ourselves to, and it too is described in our proxy statement?

MS. CLARK: Schef, could you just wait a minute. I have to take a break. I just need a minute.

MR. WRIGHT: That's okay.

(Short recess.)

BY MR. WRIGHT:

Q. You just mentioned a proxy statement. I have a very basic question. Will you agree that a company proxy statement, whether for FPL or any other company that files one, what I understand to be Securities and Exchange Commission Form 14-A, is a reliable source of information for top management compensation?

A. Yes, it is a reliable source of information, but I would add that it is a report to shareholders that's governed by SEC rules, which are very specific as to how to compile compensation and benefits costs. And I just -- you know, it's one view of pay, and it is a reliable view under the rules under which it's compiled.

Q. Okay. You mentioned that you do compare to two others. Do you compare your officers' compensation to the compensation of the top five officers of any of your customers?

MS. CLARK: Schef, I'm going to object to the question. You need to be more specific about customers.

BY MR. WRIGHT:

Q. Well, do you compare it to, say, Winn Dixie?

A. Well, I would say that, first of all, we do have a list of comparator companies that, as I said, is published in the proxy, but I am not aware which ones of them may be customers of us. I don't know, so I can't answer the question.

But furthermore, again, I would say that it's not appropriate to compare the compensation of employees in disparate positions and disparate industries and disparate sized companies of different complexities. So again, I would never compare an apple to an orange.

Q. When you make your comparisons of officers' salaries, do you make comparisons on the basis of revenues, say, for FPL versus a comparison group of companies' total revenues?

A. When we select our comparative group of companies, revenues is one of several factors we take into consideration when determining appropriate comparators, yes.

Q. What about total number of employees?

MS. CLARK: Chef, this is Susan. You're kind of over the 15 minutes.

MR. WRIGHT: Well, let me ask a few more, and then I will -- just a few more.

MS. CLARK: Thank you.

MR. WRIGHT: You're welcome.

BY MR. WRIGHT:

Q. How much of Mr. Hayes' total compensation is allocated to customers of Florida Power & Light Company in the revenue requirement that FPL is seeking in this case?

A. One moment and I can check that.

Q. Thank you.

A. Approximately 70 percent.

Q. Thank you. Would I be correct that 100 percent of the Mr. Olivera's total compensation is allocated to customers of FP&L Company?

A. Yes.

Q. Are you familiar with the Fortune listing of the 100 best places to work in the country?

A. I have a passing familiarity with it, yes.

Q. Do you know whether FPL is on that list?

A. No, I don't know.

Q. Are you familiar with Florida Trend magazine's rating or listing of the best places to work in Florida?

A. No, I am not.

Q. Would that be something that you would think that you would be aware of in your position with responsibilities for designing compensation and retention pay?

A. No, because I rely on compensation and benefits specific comparators, and frequently these lists of best places to work have a number of other factors involved.

MR. WRIGHT: Okay. And with that, I am going to stop.

MS. CLARK: Charlie?

MR. BECK: Yes. Should I go on, or do you want a break?

MS. CLARK: Kathleen has said she would like a quick break.

MR. BECK: How long would you like?

MS. COWDERY: Ten-minute break, come back at 25 of 4:00.

MR. BECK: Great.

MS. COWDERY: All right. We're off the record.

(Short recess.)

CROSS-EXAMINATION

BY MR. BECK:

Q. Ms. Slattery, I know it has been a long day for you, and I appreciate it. My name is Charlie Beck. I'm with the Office of Public Council.

Ms. Slattery, I would like to start off with the proxy statement dated April 3, 2009. Do you have that available?

A. Yes, I do.

Q. Thank you. I have a Bates stamp number for the page I'm at. It's FPL 096754?

MS. CLARK: We don't have the Bates stamp, Charlie. Can you sort of tell us what page it is of the proxy statement?

MR. BECK: It's 12 on the copy I have.

MS. CLARK: And tell us what's on it, maybe.

MR. BECK: It's an amendment to the long-term incentive plan, and it's a list of the performance measures that was being put before the shareholder meeting in May.

BY MR. BECK:

Q. The place I'm talking about, Ms. Slattery, applies to the 13 members that you mentioned in your rebuttal testimony on page 12; is that right?

A. Yes.

Q. And was this plan passed by the shareholders at the shareholder meeting on May 22nd of this year?

A. Yes, but I would like to clarify.

Q. Okay.

A. The long-term incentive plan is taken to shareholders for reapproval every five years, for reasons similar to what I described earlier today, for having an annual incentive plan for our top 13 officers, and that is that Section 162(m) of the Internal Revenue Code provides certain limitations on the deductibility of compensation expense to the company if we do not satisfy certain requirements under that section of the code related to qualifying compensation as performance-based under the definitions in that section of the code.

One of the requirements is that compensation be granted under a shareholder-approved plan. And then in simplified terms, other requirements of Section 162(m) are that there be certain performance goals related to payment of awards that cannot be subject to discretion on the part of the compensation committee.

So the page that you're looking at in the annual proxy statement is the page of the long-term incentive plan that we took to shareholders for a vote, as we do every five years, that enumerates a list of what the potential performance measures can be under the plan. It is more of a illustrative list than one that is actually used.

And furthermore, to be clear, unlike the annual incentive plan that we take to shareholders, which pertains to the top 13 officers only, the long-term incentive plan is one under which all equity compensation is granted to all participants who receive it, because of SEC rules requiring that equity compensation be granted under an S-8 registration statement, and you need a plan to do that. So there's a lot of technical complexity involved in this particular document and in this particular inclusion in the proxy statement adopted by shareholders.

Q. And the performance objectives that are listed, are there about 29?

A. Yes.

Q. That are possible for the performance plan?

A. Yes.

Q. Now, were all of those used to determine -- let me reword it. Are all of those being used to determine the long-term incentive compensation for those officers during 2009?

A. No, definitely not.

Q. Which of them are?

A. The specific requirement under the plan that's being applied is an annual net income goal, and it is included in the equity compensation award agreements of only our top officers, because Section 162(m) of the Internal Revenue Code is something that is only applicable to top officers.

Q. So of these 29 possible performance objectives, only one of them, that being net income, is actually being used in 2009 for the top officers?

A. That is my understanding. The only thing I need to clarify is that for our performance share awards, the payout of those awards is determined based on three-year achievement of the same kind of objective. It's basically the annual incentive plan objectives over a three-year period instead of a one-year period, and it's tied directly thereto.

So our long-term incentive plan is constructed in such a way that those performance shares are not granted with separate new and unique performance requirements. Instead, the award agreements tie back to average level of achievement under the annual incentive plan over the three-year period.

So specific to this long-term incentive plan document, currently only net income is being applied specifically to the award agreements granted hereunder to the top officers, just to ensure deductibility of the compensation expense, since we always strive to have the, you know, maximum efficiency in our tax planning.

Q. And the net income in this context would be the net income of FPL Group; is that correct?

A. In this context, yes, it is. And the way it works is that the award agreement for the top officers has a requirement that a net income achievement be certified by the compensation committee before vesting or payout of the award is considered. And again, that only applies to perhaps the top 13, and maybe even fewer. I haven't checked the exact number.

Q. Now, let me shift a little bit to the long-term incentive plan that applies to the executives. I believe you said there's 44 in the projected 2010 test year?

A. Yes, there are. Well, in the 2010 test year, there are 42 budgeted executive positions. But let me be clear that unlike the annual incentive plan, this long-term incentive plan applies to any equity compensation grant made in the company, whether it's to a top officer, to a junior employee, or to an exempt employee who's not an officer, because there is a registration statement with the SEC tied to this plan, and the only authorization we have to grant equity compensation awards is under the plan. So this applies to anybody who receives a grant of equity compensation.

Q. Okay. Let me ask, as an example, one of the 44 officers who's not one of the 13 -- well, I guess you're saying for all exempt employees, for the long-term incentive plan, the sole performance objective will be net income; is that correct?

A. No, that is not correct.

Q. Then I misunderstood you earlier.

A. This is very complicated. Obviously, it's very technical, so I want to make sure that I'm clear. This is a net income requirement that must be met for vesting and payout of equity compensation awards to the top officers only. For everybody else, there is no net income goal, and none of the potential goals that could be utilized under this plan are being utilized. Instead, the forms of equity compensation being awarded below top officer level consists of only two forms of award.

One is restricted stock, which is largely used for retention purposes, and generally the right to that award vests over a three-year period, and it is time vested with no separate performance requirement other than the continuation of employment. Again, it's not used very broadly, and it is an effective retention tool that we use, for example, in our Nuclear Division.

We've used it at our Turkey Point site, for example.

And the other form of equity compensation below top officer level is a performance share award, and performance share awards are granted to employees as a performance vehicle and retention tool and as part of a competitive compensation and benefits package necessary to attract, retain, and motivate our workforce. The way they work is that whatever the level of achievement is under the annual incentive plan for a three-year period is the level at which the performance share awards pay out.

So in general, we only have those two forms of award.

Q. For those two forms of award, what are the performance objectives that are used to determine the actual award to the officer?

A. With the performance shares? Is that your question?

Q. We'll start with that.

A. It would be the same objectives under the annual incentive plan. And the annual incentive plan is designed to focus our employees on the attainment of performance goals in the short term, the one-year period, and the performance share awards are designed to balance that short-term focus with a longer term or broader view. It's kind a measured approach to the attainment of our objectives.

Q. I think we're passing by each other. What I'm trying to determine is, what are the objectives that are used to determine that award of performance shares? Is it any of those 29 performance objectives we see in the proxy statement?

A. Yes, it is. I mean, you referenced a specific number. I haven't double-checked that. But it is, yes, the specific performance objectives that are listed under a different page in the proxy statement, not the ones you're looking at there.

Let me direct you to another page. In the proxy statement as printed, it's page 47. I don't have the Bates stamp page.

Q. Okay. I have that.

A. And also, there is a description in our proxy statement of how our performance share awards work that I thought might be helpful. On page 52, it says -- this is a description of how it works for the proxy named officers, but it's similar below that level.

A number of performance shares, a baseline award is granted, and the performance period begins on January 1st in the year of grant and ends on December 31st three years later, after three years. At the end of the performance period, the average of the executive's total performance-based adjustments under the annual incentive plan for the three years in the performance period is multiplied by the target or baseline number of shares to determine the final award payout.

On this plan, this performance share plan, there is a maximum of 160 percent of targeted shares that can be paid out, so it is a lower maximum than the annual incentive plan. But other than that, it just takes the annual incentive plan performance-based adjustments and applies them here for the three-year period.

Q. And referring to that, what are the performance objectives that are used to determine the amount that's granted? Is it that same list of 29 possible objectives?

A. Could you please give me the page number on which you're looking for the 29? Is this back on page 12 of the proxy? Because the answer is no if that's the case.

Q. Okay. Where would I find them?

A. Page 47. And for the Group officers, it would be page 47 and 48.

So it is not the list of 29 on page 12. It is rather the performance objectives on pages 47 and 48.

Q. And there's about 15, perhaps? I haven't counted them. But these are now used for all except the top 13 officers?

A. No. It's fundamentally the same for both the top officers and those below as far as how we determine the payout level. It's just that for the top 13, those awards have to cross what I call the IRS Section 162(m) hurdle, which is the net income requirement before any payout can be made to ensure the deductibility of the compensation expense. So I call that the Section 162(m) hurdle.

And it does not determine the actual payout amount or level. Rather, it's determined in the same way as for the other officers, which is the performance-based adjustment from the annual incentive plan over the three-year period to determine the multiple of the baseline award that will be received with a maximum of 160 percent.

Q. The indicators that are shown on page 47, do they apply to all exempt employees? In other words, this is not just officers, but it's all exempt employees?

A. Yes. Exempt employees also get the performance-based adjustments.

Q. And so all those indicators would also apply to all exempt employees, or do I have that right?

A. Just one moment while I check.

(Off the record briefly.)

MS. CLARK: Charlie, would you ask your question again?

MR. BECK: I was afraid you were going to say that.

BY MR. BECK:

Q. Ms. Slattery, there's about 15 indicators shown on page 47 of the proxy statement dated April 3, 2009. And my question is, do those indicators apply to the incentive compensation for all exempt employees of Florida Power & Light Company?

A. Yes. These indicators are included in the performance assessment of all exempt employees.

Q. So this is a list of some, but not all?

A. That's correct.

Q. But all of these would be included in the performance objectives. It's just that there may be others in addition to these?

A. Yes.

Q. And where would we find where the others are?

A. It depends on the level of employee, but additional performance objectives that may impact the payout level would be the NextEra performance objectives on page 48, one page behind.

Q. And would those NextEra objectives be included in the incentive compensation for Florida Power & Light exempt employees?

A. Well, let me make clear that no Florida Power & Light Company employee has performance objectives set out for them under the annual incentive plan related to NextEra's performance. So these are not objectives that Florida Power & Light Company employees have in their key objectives or as part of their annual incentive award.

But to the extent that FPL Group's performance impacts the value of the payout of the performance share award, NextEra performance does impact Group. But again, no Florida Power & Light Company employee has any performance objective that he or she is assigned to achieve related to NextEra's performance.

Q. Now, on page 47 of the proxy, it lists the performance targets for 2008, does it not?

A. Which page, please?

Q. Page 47.

A. Yes.

Q. And understanding that the actual numbers probably changed for 2009, but are the indicators the same for 2009?

A. They're fundamentally the same, but there's always potential for some change, particularly with regard to milestone measures. So, for example, the last measure for 2008 would be one that would have been specific to 2008 because it was a milestone measure for approval for generation additions. And so for 2009, I believe that would have come off, and different milestone measures may or may not have been added. But the majority of our indicators are consistent from year to year.

Q. Is the outcome of the rate case an indicator for any employees?

A. Yes, it is. It's something that we want many employees at Florida Power & Light Company to be focused on, since there's a tremendous amount of effort needed to file the case. So definitely the support of and the outcome of the rate case is going to impact the performance assessment for the company and a great many employees.

Q. So that would be an indicator that applies to 2009, but did not apply to 2008?

A. Yes, that's correct.

Q. Are there any others?

A. None that I'm aware of. I just don't have it with me, but I don't recall any others, subject to check.

Q. All right. Let's move on to another topic, if we could. Do you have the response to the Attorney General's Second Set of Interrogatories, Number 76?

A. Yes, I do.

Q. And on page 1 of 5 of the attachment, can you generally describe what's shown on that page?

A. Page 1 of 5 is the grand total of the EACs requested in the interrogatory, which are then broken down by EAC on pages 2 through 5. And on page 1 with the grand total, there is a section for 2009, 2010, and 2011, specifically related to the total of four different wage types.

Q. Could you please state what EAC stands for?

A. It's an acronym that has been used for so long in this company that I've actually forgotten it, but it may be expense analysis code.

Q. And what I would like to ask you to do is focus on page 1 of 5, the middle chart that shows the amount for 2010.

A. Yes.

Q. And the total amount shown for all of the rows under the portion is 137,529,665. Do you see that?

A. Yes, I do see that.

Q. Do you know what portion of that would be applicable to the 13 named individuals in the proxy statement?

A. I do not know what amount would be applicable to them, but they would be a subset of this amount here. They're included in the executive column on the left, but that column includes data for more than just 13 people.

Q. How many people are included in the executive column? That's the column that totals $48,471,915?

A. Right. For 2010, we have 42 executives budgeted in the executive location, 42 positions, so 13 of the 42.

Q. Do you have anything available that would show what portion of that figure would be applicable to the top 13?

A. No, I do not.

Q. Would it be possible to get that as a late-filed exhibit?

A. Yes, it would be.

MR. BECK: Okay. Susan, could we have that? I'm not sure what we're up to. Number 5?

MS. CLARK: I think it is Number 5. Can you give us a title?

MR. BECK: Top 13 officer portion of

compensation -- of the answer included in response to AG 76. That's an awful name. You all think of a good name for it. Or how about breakdown of amounts shown in response to AG 76, Attachment 1? We'll be breaking it down between the top 13 and the remaining --

MS. CLARK: Breakdown of amounts shown on --

THE WITNESS: You just want a breakdown of 2010 on page 1 of 5?

MR. BECK: Yes. So it would show what portion applies to the top 13, and then I guess the remainder that applies to the other -- what would it be? Twenty-nine or 30.

MS. CLARK: I have "Breakdown of amounts shown on executive salary for 2010."

(Late-filed Deposition Exhibit Number 5 was identified for the record.)

BY MR. BECK:

Q. Let's move on to something else, page 22 of your rebuttal testimony.

MS. CLARK: I spoke wrong. It's incentives and benefits. Were you moving on, Charlie?

MR. BECK: Yes.

MS. CLARK: We didn't hear the question.

BY MR. BECK:

Q. Ms. Slattery, could you refer to page 22 of your rebuttal testimony?

A. Yes, I have it.

Q. At line 15, you say the company sometimes utilizes a stock repurchase program under which it purchases on the open market many of the shares used to satisfy awards under the long-term incentive plan. Do you see that?

A. Yes, I do.

Q. Do you know to what extent or what portion of the stock incentive awards granted in 2008 were made by purchasing on the market?

A. None. In the last several years, we have not done stock repurchase, although prior to that it was a common practice for us, and it is always an option for the future. But for the last several years, we've used new issue shares only to satisfy awards.

Q. All right. Let's move on to another topic, if we could. You mentioned that one of your concerns about having the right amount of compensation is poaching, and I was wondering what poaching means to you.

A. Poaching is slang for what we call sourcing passive candidates for vacancies. That's what recruiters like to use, and it means that recruiters or headhunters will contact currently employed individuals and try no induce them to leave their current employer to go with a new employer.

Q. Do you conduct exit interviews, or not you, but does the company conduct exit interviews where it analyzes whether employees have been poached?

A. I know that we do conduct exit interviews, and I am not certain to what extent we collect information on poaching or analyze it.

Q. So you're not aware of any analysis of that, at least?

A. I am not, but again, my position in compensation and benefits is such that I am -- I'm not in recruiting or employee relations, which would be the two functions most likely to be involved in that activity.

Q. I believe you testified this morning that employee turnover at Florida Power & Light is projected to increase from about 7 percent in 2009 to 9 1/2 percent in 2010; is that right?

A. Yes, I believe that's correct.

Q. And 10.4 percent in 2011?

A. Yes, that's correct.

Q. To what do you attribute the projected increase in turnover?

A. As I stated this morning, I did not prepare those forecasts. A peer in Human Resources did, and I have not discussed with him what his assumptions are, although I believe that historic actuals generally play a role in his future forecasts.

Q. Do you know what areas or line of work where this increased turnover is projected to occur?

A. I do not have that information.

Q. Would you describe the retirement plan of FPL -- and here I'm referring to page 25 of your testimony -- as a defined benefit plan or a defined contribution plan?

MS. CLARK: Charlie, would you tell us what you mean by those terms, please?

MR. BECK: Well, I'm going to -- defined benefit plan or defined contribution plan?

MS. CLARK: I'm sorry. Kathleen indicates she can answer the question.

A. But I would like to know, are you looking at my direct or my rebuttal?

Q. Direct, I believe.

A. Direct testimony, on which pages, please?

Q. Twenty-five. On page 25, you apparently talk about the retirement plan.

A. FPL provides both a defined benefit and a defined contribution plan. The defined contribution plan is a 401(k) plan, and the defined benefit plan is a cash balance style pension plan which kind of looks to the employees more like a defined contribution plan, but the accounting and IRS rules allow us to treat it as a defined benefit plan.

We provide evidence as an exhibit to my direct testimony of the approximate value to employees and competitive position of those plans as a combined retirement plan value to show that we are substantially below market compared to the utility industry or our peer group companies regarding the total value provided from the two plans combined.

Q. Okay. Thank you. Ms. Slattery, at page 10 of your direct testimony, at lines 8 through 10, you state that FPL's total compensation and benefits cost is projected to increase from 1.014 billion in 2006 to 1.261 billion in 2010.

A. Yes.

Q. Do you know what portion of that increase is for employees making total compensation greater than $165,000 per year?

A. No, I do not.

Q. Is it possible to calculate that?

A. I don't believe that I could easily calculate that, no. I don't know if it would be possible or impossible to calculate that. It would require expertise beyond what I have.

MR. BECK: Well, I'll let that go, then. Ms. Slattery, thank you very much. I think that's all I have.

THE WITNESS: Thank you.

MS. CLARK: Kathryn, I guess that concludes the deposition.

MS. COWDERY: Okay. Then we are concluded. Are there any matters that we need to cover that haven't been covered at this point?

MS. CLARK: No. I think we got the time that you've asked us to try and get late-filed exhibits, to the extent we have them, and e-mail them to the court reporter, which we will endeavor to do. I'm just trying to see if I have any other notes.

MS. COWDERY: I think that would be it, then. Thank you everybody, and we will go off the record.

(Deposition concluded at 4:08 p.m.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA:

COUNTY OF LEON:

I, MARY ALLEN NEEL, Registered Professional Reporter, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that a review of the transcript was requested; that my shorthand notes were thereafter translated under my supervision; and that the foregoing pages numbered 1 through 177 are a true and correct record of the aforesaid proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor relative or employee of such attorney or counsel, or financially interested in the foregoing action.

DATED THIS 24th day of August, 2009.

MARY ALLEN NEEL, RPR, FPR
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August 24, 2009

SUSAN CLARK, ESQUIRE
Radey, Thomas, Yon & Clark, P.A.
301 South Bronough Street, Suite 200
Tallahassee, Florida 32301

Dear Ms. Clark:

Re: Petition for increase in rates by FPL
Docket No. 080677-EI

Enclosed is your copy of the deposition of KATHLEEN M. SLATTERY taken in the above matter on August 21, 2009.

Since reading and signing was not waived, please make arrangements with the witness to read your copy of the transcript and make any corrections on the errata sheet on the following page.

Please forward the completed errata sheet to Kathryn G.W. Cowdery for attachment to the original transcript and a copy to Charlie. You should also attach a copy to your transcript.

Thank you for your cooperation in this matter.

Sincerely,

Mary A. Neel

cc: Kathryn G. W. Cowdery, Esq.
Charlie Beck, Esq.

ERRATA SHEET

Under penalties of perjury, I have read the foregoing transcript of my deposition, pages 1 through 177, and hereby subscribe to same, including any corrections and/or amendments listed below.

DATE KATHLEEN M. SLATTERY

PAGE/LINE	ERROR OR AMENDMENT	REASON FOR CHANGE

Reporter: Mary A. Neel - Date of Deposition: 08/21/09
Petition for rate increase by FPL - Docket No. 080677-EI

ERRATA SHEET

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8/25/09 Kathleen M Slattery
DATE KATHLEEN M. SLATTERY

PAGE/LINE	ERROR OR AMENDMENT	REASON FOR CHANGE
11,9	Change "base" to "based"	Wrong word
22,8	Change "holidays" to "11, holidays"	Missed word
27,3	Change "department" to "departments"	Plural
29,17	Change "to that when" to "to when"	Added word
37,13	Change "call passive" to "call it passive"	Missing word
44,22	Change "company?" to "company."	Wrong punctuation
49,15	Change "our performance base" to "are performance based"	Wrong words
52,16	Change "dozen" to "dozens"	Plural
55,15	Change "efficiency milestone" to "efficiency and milestone"	Missing word
57,15	Change "unit" to "units"	Plural
59,18	Change "an income" to "a net income"	Wrong word

Reporter: Mary A. Neel - Date of Deposition: 08/21/09
Petition for rate increase by FPL - Docket No. 080677-EI

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8/25/09 — DATE

Kathleen M Slattery — KATHLEEN M. SLATTERY

PAGE/LINE	ERROR OR AMENDMENT	REASON FOR CHANGE
60,1	Change "200,00" to "200,000"	Typo
85,3	Change "of" to "on"	Wrong word
89,8	Change "individual business" to "individual, business"	Missing comma
103,10	Change "before" to "because"	Wrong word
115,22	Change "little" to "total"	Wrong word
105, 11-12	Change "experience, able to--they can make" to "experience, ability and training and we cannot make"	Wrong and missing words
134,11	Change "WAG" to "guess"	Wrong word
139,17	Change "5" to "what"	Wrong word
147,22	Change "FLP" to "FPL"	Typo
153,5	Change "statement?" to "statement."	Wrong punctuation

Reporter: Mary A. Neel - Date of Deposition: 08/21/09
Petition for rate increase by FPL - Docket No. 080677-EI

ERRATA SHEET

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8/25/09 Kathleen M Slattery
DATE KATHLEEN M. SLATTERY

PAGE/LINE	ERROR OR AMENDMENT	REASON FOR CHANGE
153,24-25	Change "to two others" to "to others"	Added word
155.9	Change "Hayes'" to "Hay's"	Spelling error
168.6	Change "no Florida" to "no unallocated Florida"	Missing word
168.16	Change "no Florida" to "no unallocated Florida"	Missing word

Reporter: Mary A. Neel - Date of Deposition: 08/21/09
Petition for rate increase by FPL - Docket No. 080677-EI

080677 Hearing Exhibit - 00002203

Back up for Document KS-3

These tables document the estimated escallation of FPL's 1988 total compensation per employee to 2010 using the various market indices. The 1988 total was obtained from the C-33 schedule for Docket No. 080677-EI. Sources are listed below for the escallation factors for WorldatWork and CPI. The WaW 2010 and 2011 percentages are conservative estimates and in line with estimates from Hewitt Associates and Conference Board.

Total Cash Compensation per Employee

	World at Work					CPI		
	Exempt	Non-Exempt	Average					
1988				42505	1988		42505
1989	5.40%	5.20%	5.30%	44758	1989	4.80%	44545
1990	5.50%	5.40%	5.45%	47197	1990	5.40%	46951
1991	5.00%	5.00%	5.00%	49557	1991	4.20%	48923
1992	4.70%	4.60%	4.65%	51861	1992	3.00%	50390
1993	4.30%	4.20%	4.25%	54065	1993	3.00%	51902
1994	4.00%	4.00%	4.00%	56228	1994	2.60%	53251
1995	4.00%	3.90%	3.95%	58449	1995	2.80%	54742
1996	4.10%	3.80%	3.95%	60758	1996	2.90%	56330
1997	4.30%	4.10%	4.20%	63310	1997	2.30%	57626
1998	4.50%	4.10%	4.30%	66032	1998	1.50%	58490
1999	4.40%	4.10%	4.25%	68838	1999	2.20%	59777
2000	4.60%	4.30%	4.45%	71902	2000	3.40%	61809
2001	4.60%	4.30%	4.45%	75101	2001	2.80%	63540
2002	3.90%	3.70%	3.80%	77955	2002	1.60%	64556
2003	3.60%	3.50%	3.55%	80722	2003	2.30%	66041
2004	3.60%	3.50%	3.55%	83588	2004	2.70%	67824
2005	3.70%	3.60%	3.65%	86639	2005	3.40%	70130
2006	3.80%	3.70%	3.75%	89888	2006	3.20%	72375
2007	3.90%	3.80%	3.85%	93349	2007	2.83%	74423
2008	3.90%	3.80%	3.85%	96943	2008	3.81%	77258
2009	3.90%	3.80%	3.85%	100675	2009	2.00%	78803
2010	3.00%	3.00%	3.00%	103695	2010	2.00%	80380
2011	3.00%	3.00%	3.00%	106806	2011	2.10%	82068

Growth based on CPI:

	2010	2011
CPI Projection	80380	82068
FPL (C-35, line 4)	95639	96471
Difference	(15259)	(14403)

Growth based on WaW:

	2010	2011
WaW Projection	103695	106806
FPL (C-35, line 4)	95639	96471
Difference	8056	10335

Growth based on BLS Comp per Hour (non-Farm):

	2010	2011
Comp / Hr Projection	99782	103574
FPL (C-35, line 4)	95639	96471
Difference	4143	7103

Sources:

E17, K17	1988 FPL Pay and Benefits: MFR C-33--line 4, column 3
Col. D	WorldatWork 2008-09 Salary Budget Survey
CPI	Consumer Price Index (All urban consumers)
WaW	1988-1995: Non-Ex = NE salaried (hourly not tracked) 1996-2011: Non-Ex = NE hourly - non-union

EXHIBIT 1
Witness Slattery
Date 8-21-09
Reporter Mary A. Neel

COMPENSATON PER HOUR (Non-Farm Business Sector)

1988		42505
1989	2.60%	43610
1990	6.10%	46270
1991	5.10%	48630
1992	5.30%	51208
1993	2.00%	52232
1994	1.70%	53120
1995	2.10%	54235
1996	3.40%	56079
1997	3.10%	57818
1998	6.00%	61287
1999	4.70%	64167
2000	7.20%	68787
2001	4.00%	71539
2002	3.60%	74114
2003	4.00%	77079
2004	3.70%	79930
2005	4.00%	83128
2006	3.80%	86287
2007	4.10%	89824
2008	3.70%	93148
2009	3.50%	96408
2010	3.50%	99782
2011	3.80%	103574

TOTAL BENEFITS COSTS
2003 - 2010

	2010	2009	2008	2007	2006	2005	2004	2003
Health & Welfare Benefits	110,032	94.712	88.963	87.148	81,932	74,864	67,080	70.321
Retirement / Post-Employment Benefits	6,858	(18,332)	(30,144)	(15,626)	(19,058)	(12,967)	(42,001)	(39,056)
Statutory Benefits	81,465	77,987	74,320	73,469	70,575	69 783	66.927	66,147
Total Benefits	198,355	154,367	133,139	144,991	133,449	131 680	92.006	97,412

These totals agree with benefits costs reflected on MFR C-35.

Health & Welfare includes: life, medical, dental insurance; educational assistance; employee welfare; nuclear child dev ctr
Retirement / Post-Employment includes: employee savings plan, pension, post-retirement (FAS 106), post-employment/disability (FAS 112)
Statutory includes: FICA, FUTA/SUTA, workers' compensation

EXHIBIT 2
Witness Slattery
Date 8-21-09
Reporter Mary A. Neel

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080677-EI & 090130-EI EXHIBIT 38

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS Armando J. Olivero (AJO-1)

DATE 08/26/09

Florida Power & Light Company

Biographical
Information

Armando J. Olivera
President and Chief Executive Officer

Armando Olivera is president and chief executive officer of Florida Power & Light Company (FPL), a subsidiary of FPL Group, Inc., and one of the largest investor-owned electric utilities in the nation. He was appointed to his current position in June 2003.

Under Mr. Olivera's leadership, FPL has invested heavily in ensuring reliable service and meeting strong current and projected growth in demand for electric power in its vast service territory. The company is a clean energy leader and is moving forward to bring three state-of-the-art solar power plants to Florida as well as additional emissions-free nuclear power. FPL has the number one energy efficiency program in the U.S., one of the most efficient fossil power plant fleets in the nation and has taken a number of additional actions to mitigate high fuel costs. The company has implemented an industry-leading program to harden its electric system against hurricanes as well as ensure everyday reliability.

Mr. Olivera joined FPL in 1972 and has served in a variety of management positions in the areas of transmission and distribution operations, fuels management, and strategic planning and resource allocation. Prior to being named to his current role, he was senior vice president of FPL's Power Systems business unit.

Mr. Olivera holds a bachelor of science degree in electrical engineering from Cornell University and a master of business administration degree from the University of Miami. He also is a graduate of the professional management development program of the Harvard Business School.

In 2007, Mr. Olivera was appointed by Florida Governor Charlie Crist to serve on the Florida Governor's Action Team on Energy and Climate Change, which is tasked with developing a comprehensive strategy that achieves targets for statewide greenhouse gas reductions.

He is a past president of the Southeastern Electric Exchange, immediate past chairman of the Florida Reliability Coordinating Council (FRCC), and a member of the board of Enterprise Florida, as well as a member of Cornell University Engineering Council and Cornell University Council.

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080677-EI & 090130-EI EXHIBIT 39

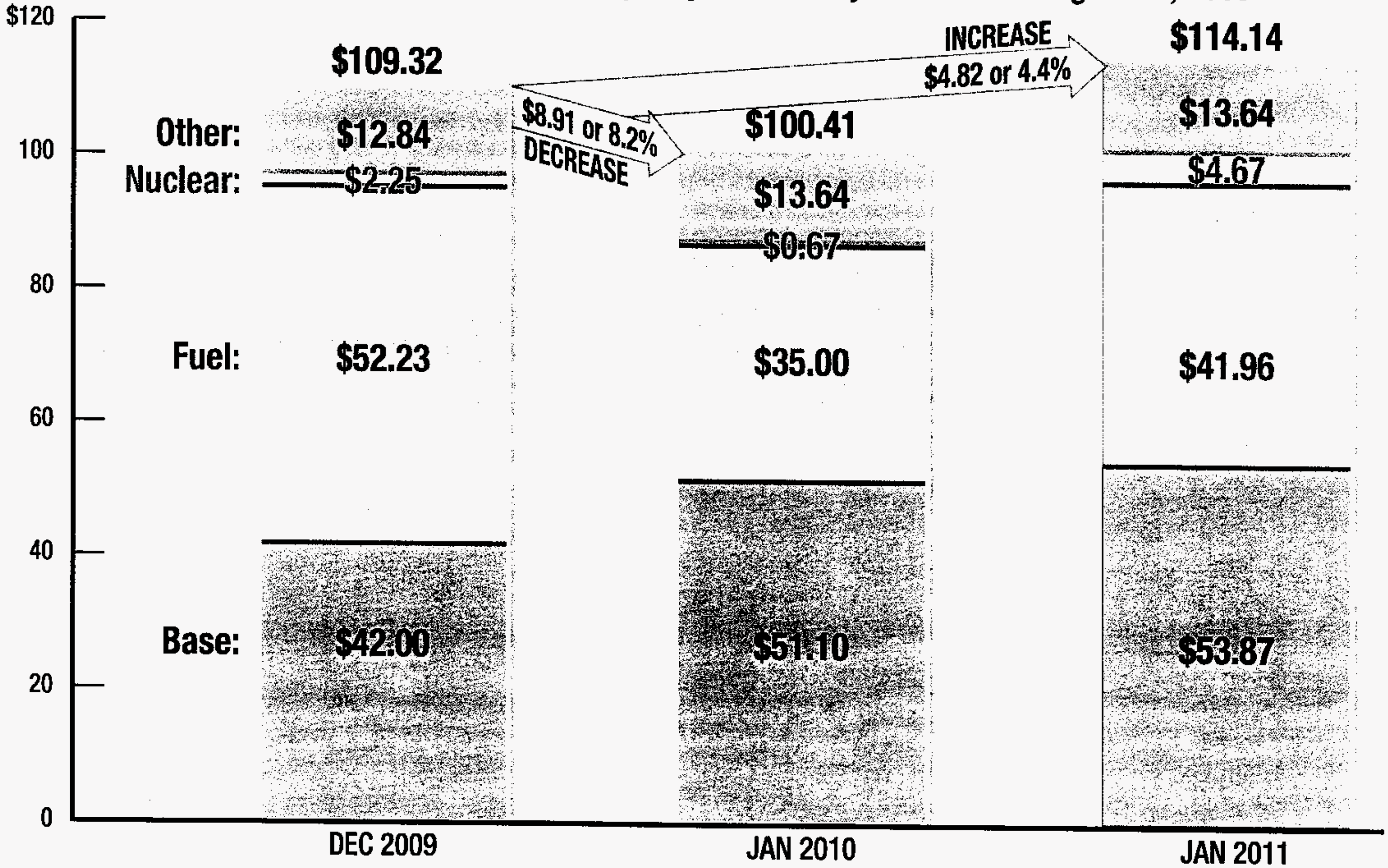
COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS Armando J. Olivero (AJO-2)

DATE 08/26/09

FPL Typical Residential 1,000 kWh Bill

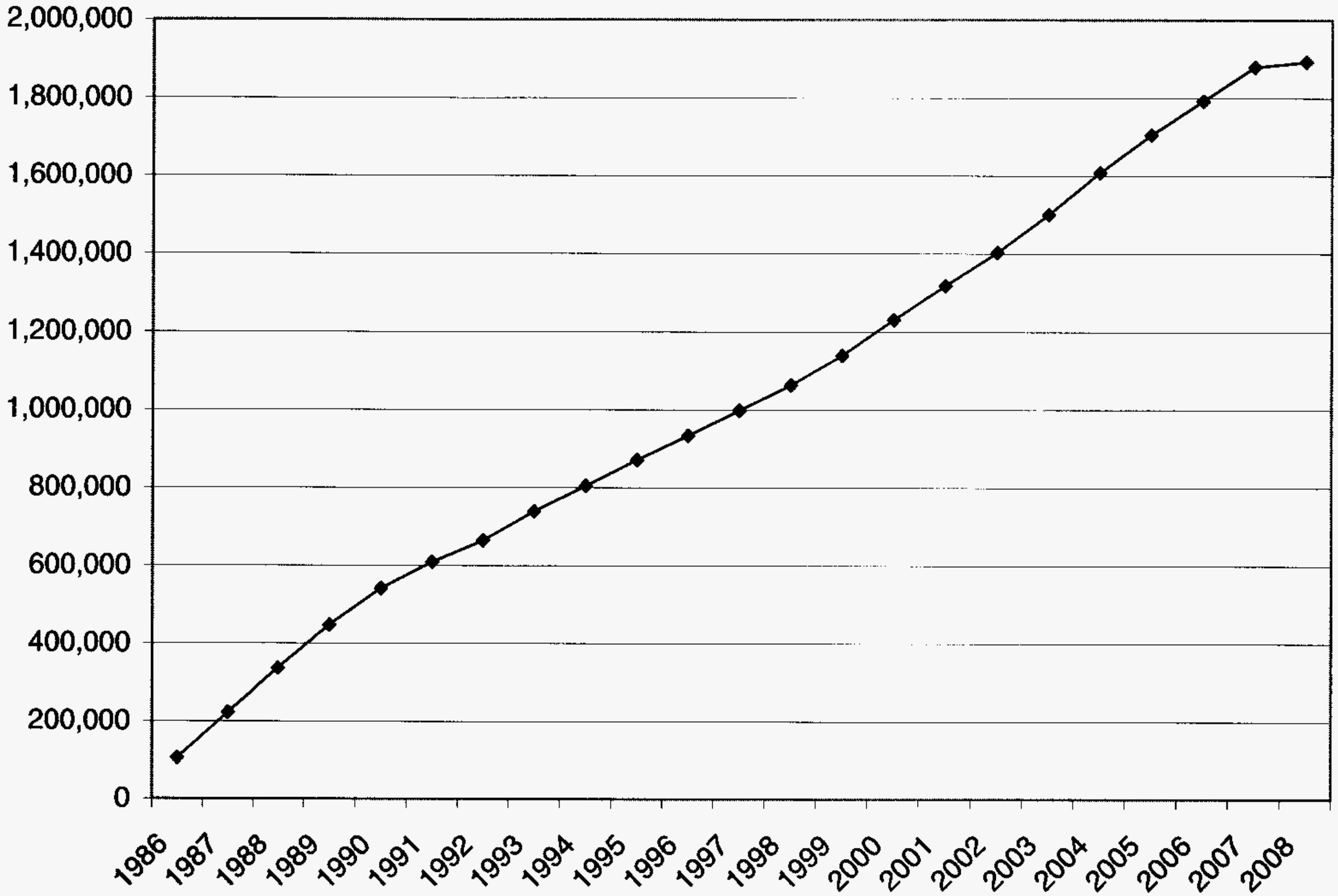
Updated to reflect estimated adjustments to base reflected in KO-16, and 2010 & 2011 Fuel and Capacity Clause Projections as of August 20, 2009



Source: Exhibit RBD-2; Updated August 20, 2009
Fuel prices based on fuel cost projections as of August 10, 2009
"Other" includes clauses other than fuel and nuclear recovery, such as energy conservation and gross receipts tax

Docket No. 080677-EI
FPL Typical Residential
1,000 kWh Bill for
December 2009, January
2010 and January 2011
Exhibit AJO-2, Page 1 of 1
Updated August 20, 2009

Cumulative Customer Growth Since 1985

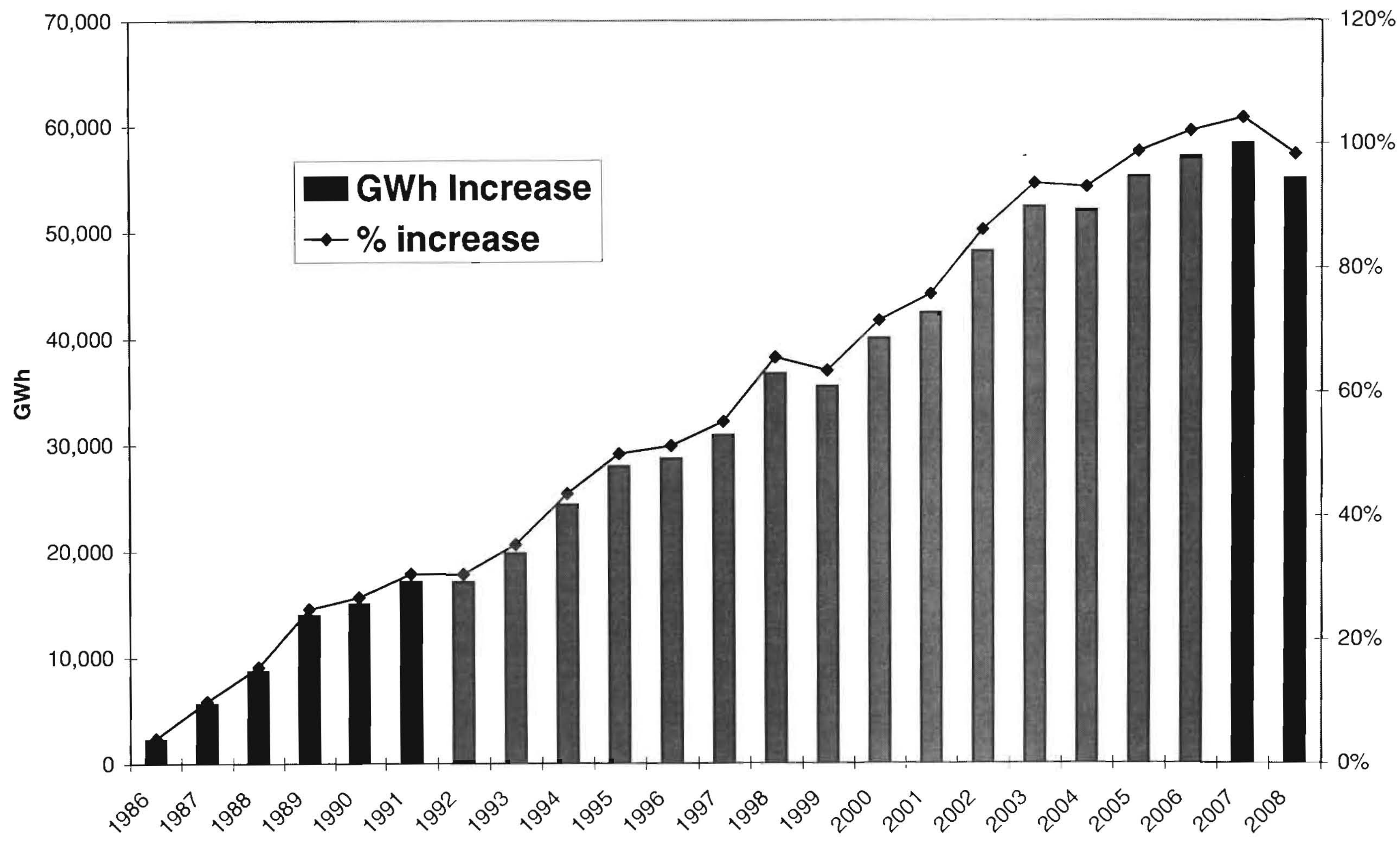


Docket No. 080677-EI
Cumulative Customer Growth Since 1985
Exhibit RM-1, Page 1 of 1

THE NUMBER OF CUSTOMERS HAS INCREASED BY ALMOST 1.9 MILLION SINCE 1985.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 40
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Rosemary Morley (RM-1)
DATE 08/27/09

Cumulative Increase in NEL Since 1985

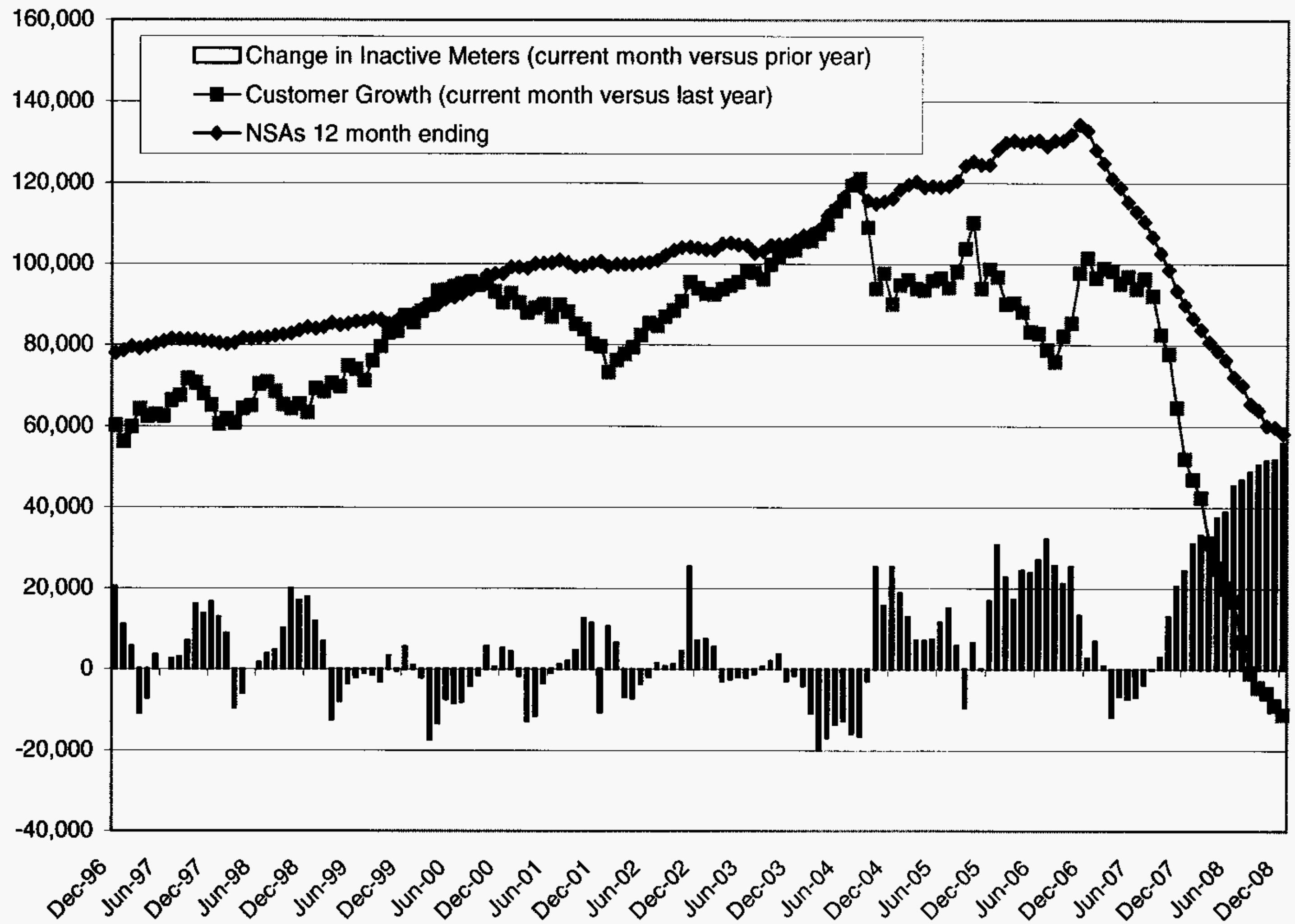


Docket No. 080677-EI
Cumulative Increase in NEL Since 1985
Exhibit RM-2, Page 1 of 1

ENERGY SALES HAS INCREASED BY 98% SINCE 1985.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 41
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Rosemary Morley (RM-2)
DATE 08/27/09

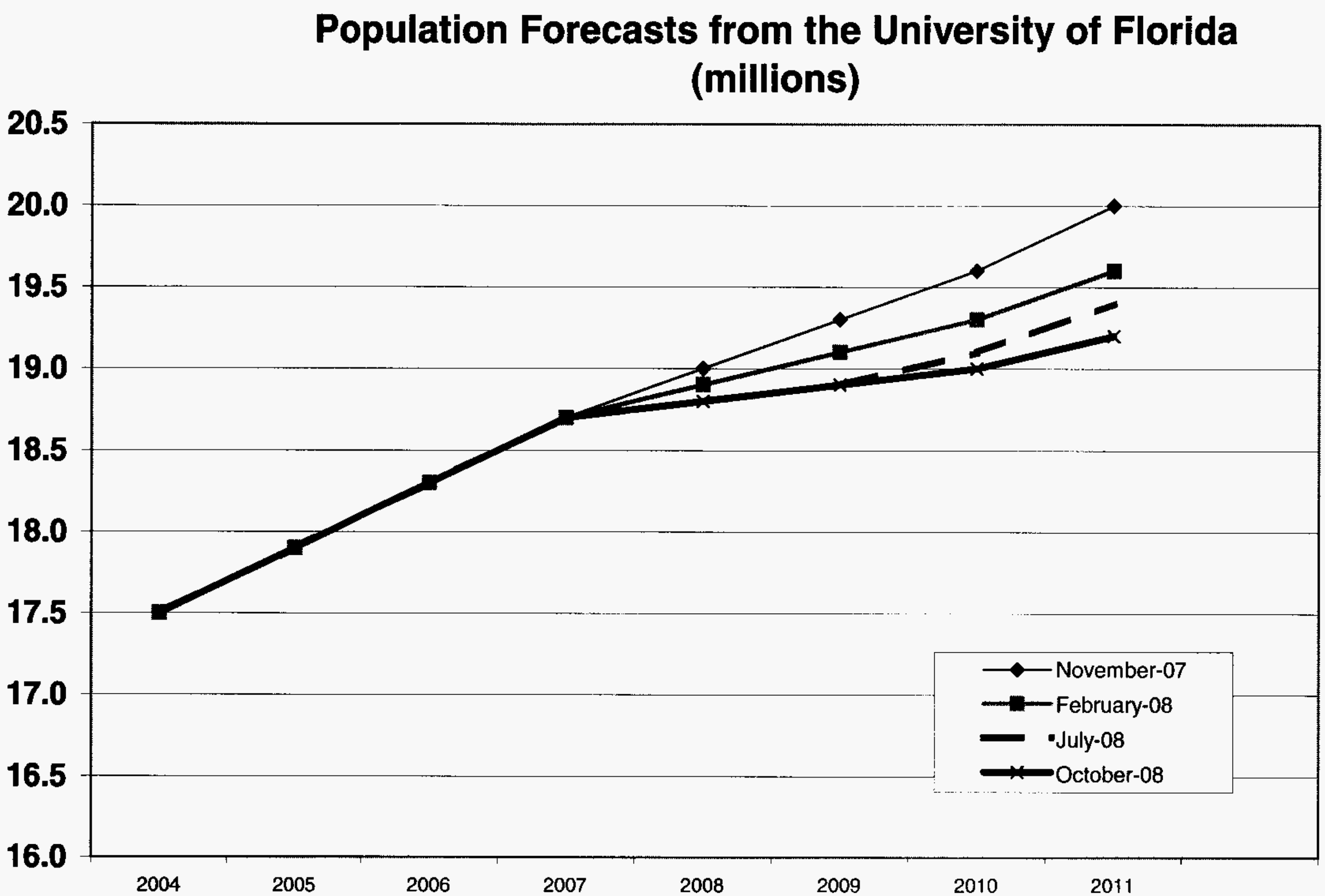
NSAs, Customer Growth and the Change in Inactive Meters



THE NUMBER OF CUSTOMERS IS NOW DECLINING DESPITE A LARGE NUMBER OF NSAs. THE EXPANDING NUMBER OF INACTIVE METERS IS DEPRESSING CUSTOMER GROWTH.

Docket No. 080677-EI
NSAs Customer Growth and the Change in Inactive Meters
Exhibit RM-3, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 42
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Rosemary Morley (RM-3)
DATE 08/27/09



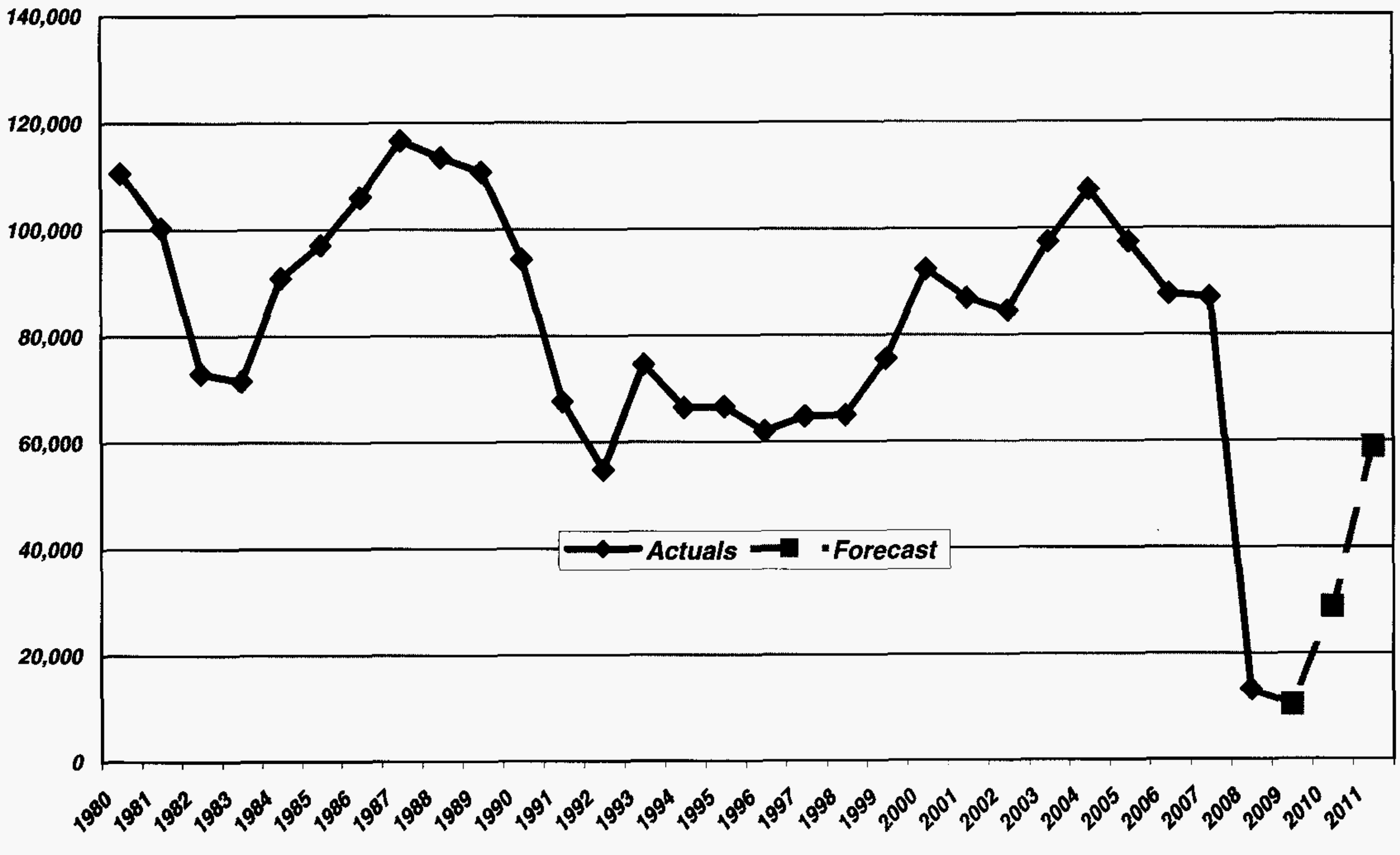
Docket No. 080677-EI
Population Forecasts from the University of Florida
Exhibit RM-4, Page 1 of 1

THE UNIVERSITY OF FLORIDA HAS BEEN REVISING THE STATE'S POPULATION FORECAST DOWNWARD.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 43
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Rosemary Morley (RM-4)
DATE 08/27/09

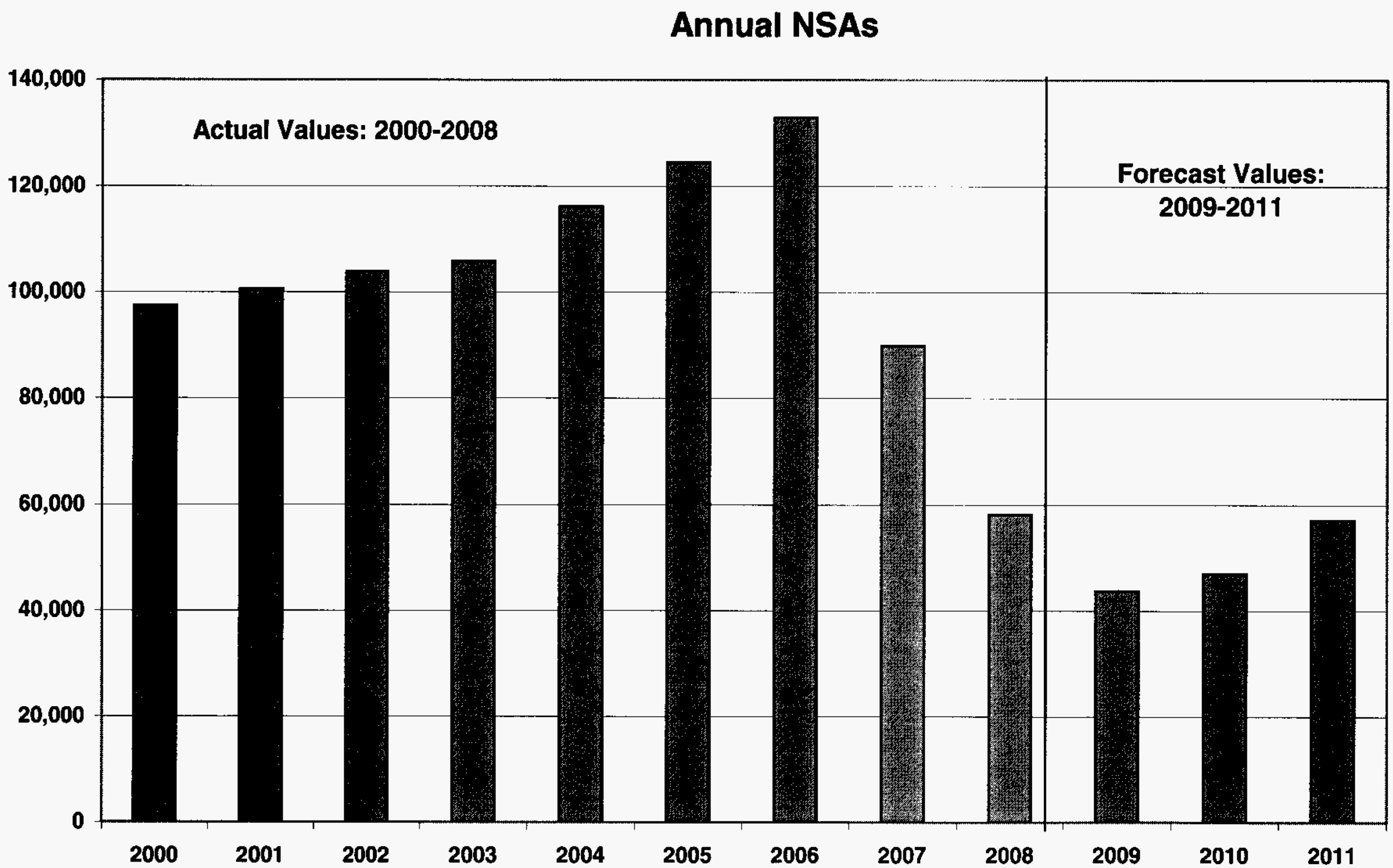
Docket No. 080677-EI
Increase in the Average Annual Number of Customers
Exhibit RM-5, Page 1 of 1

Increase in the Average Annual Number of Customers



THE FORECAST SHOWS CUSTOMER GROWTH BELOW HISTORICAL LEVELS THRU 2011.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 44
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Rosemary Morley (RM-5)
DATE 08/27/09



Docket No. 080677-EI
Annual NSAs
Exhibit RM-6, Page 1 of 1

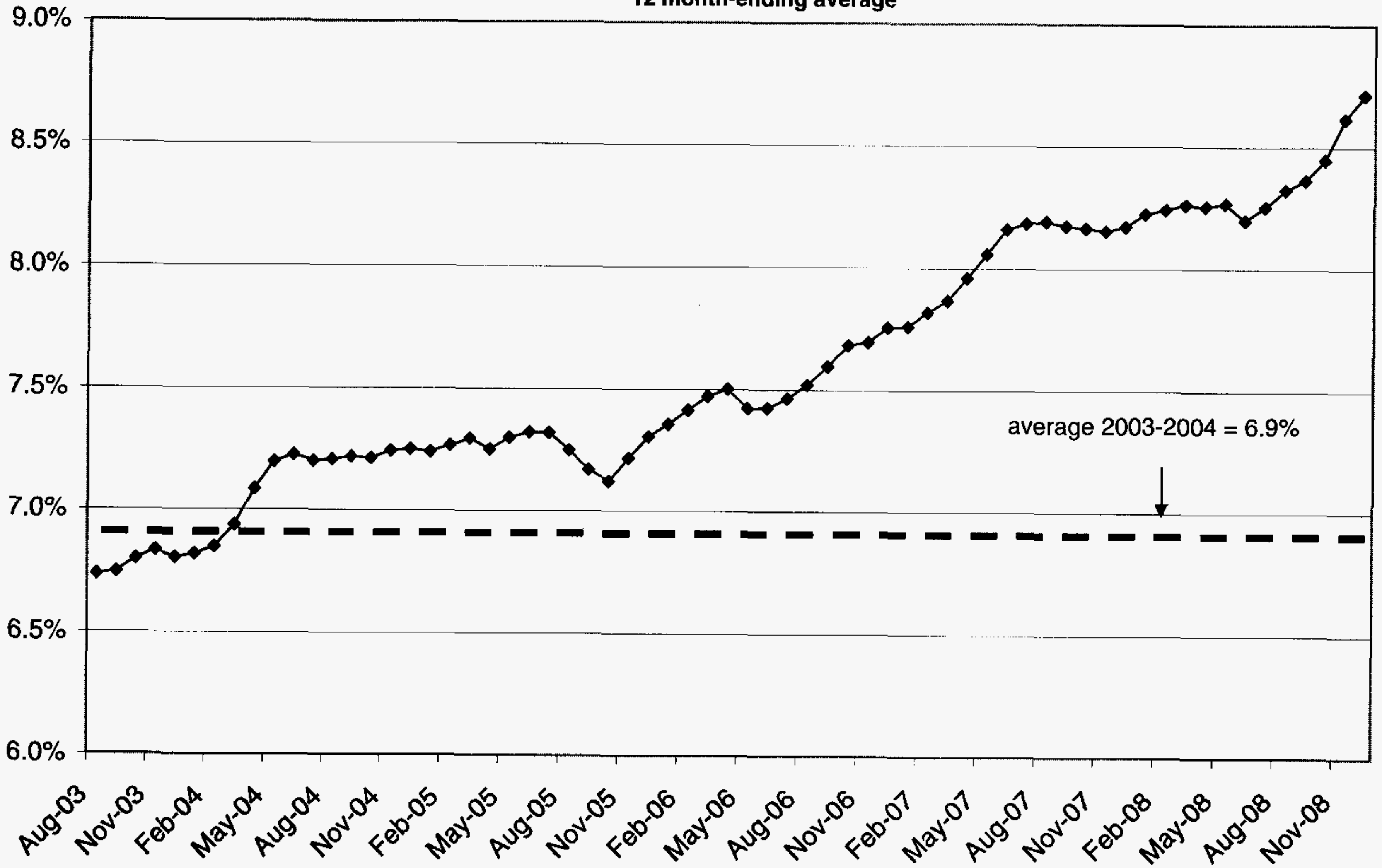
WHILE BELOW PAST LEVELS, THE ABSOLUTE NUMBER OF NSAs FORECASTED REMAINS HIGH.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 45
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Rosemary Morley (RM-6)
DATE 08/27/09

Increase in Minimal Usage Customers

Percentage of Residential Customers Using 1 kWh and 200 kWh

12 month-ending average



Docket No. 080677-EI
Increase in Minimal Usage Customers
Exhibit RM-7, Page 1 of 1

AN INCREASE IN THE NUMBER OF RESIDENTIAL CUSTOMERS USING MINIMAL AMOUNTS OF ELECTRICITY HAS COINCIDED WITH THE ONSET OF THE HOUSING CRISIS.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 46
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Rosemary Morley (RM-7)
DATE 10/23/09

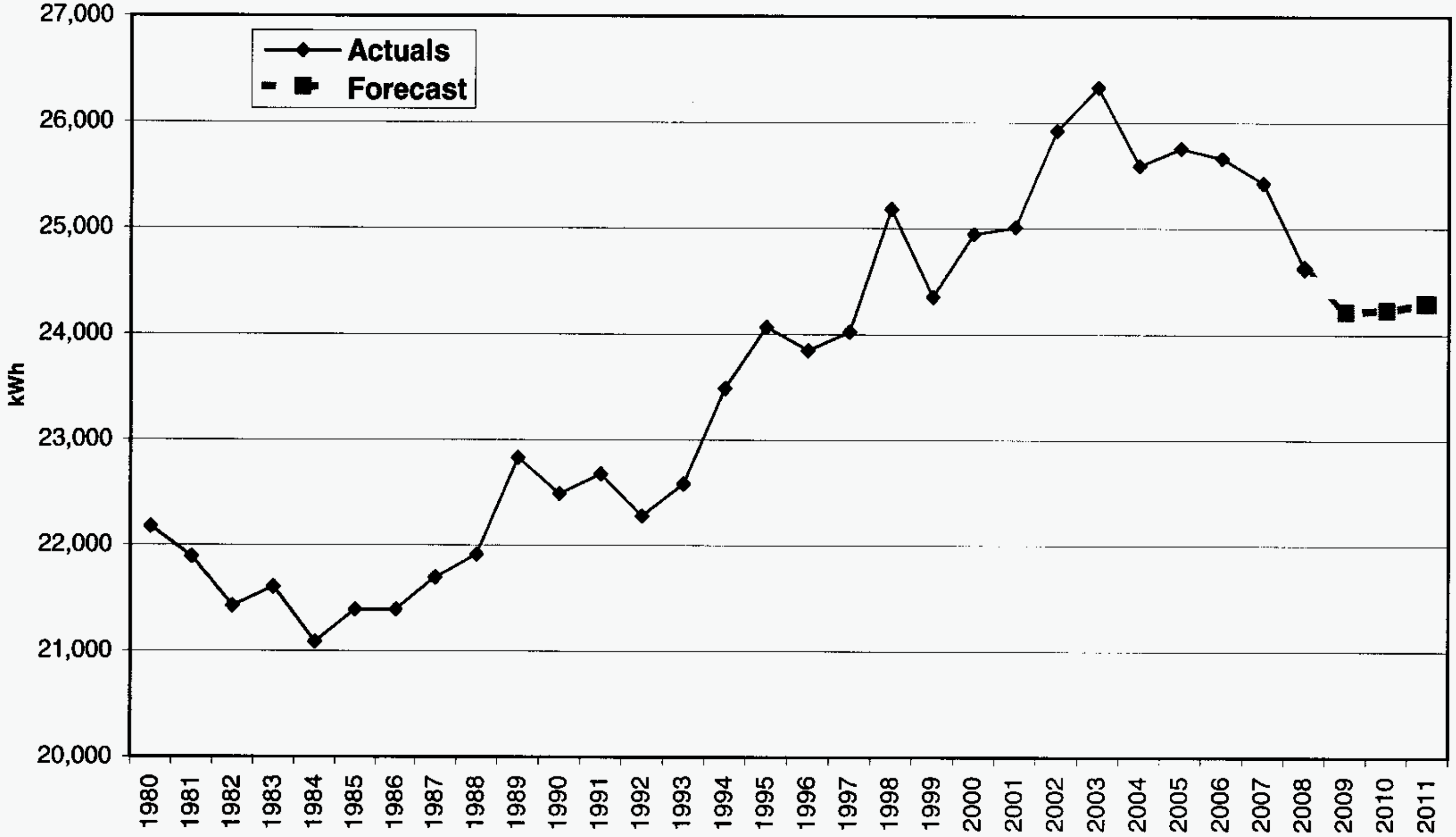
Forecasting Variance
Energy Use per Customer (kWh)

	Output of Econometric Model	Forecast with adjustments	Actual	Actual Weather Normalized
Nov-08	1,830	1,766	1,753	1,805
Dec-08	1,764	1,706	1,668	1,722
Jan-09	1,838	1,765	1,775	1,769
Total	5,432	5,237	5,195	5,296
Absolute Variance (% of Actuals)	4.6%	0.8%		
Absolute Variance (% of Weather Normalized Actuals)	2.6%	1.1%		

THE ADJUSTMENTS TO THE OUTPUT OF THE ECONOMETRIC MODEL ARE APPROPRIATE.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 47
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Rosemary Morley (RM-8)
DATE 08/27/09

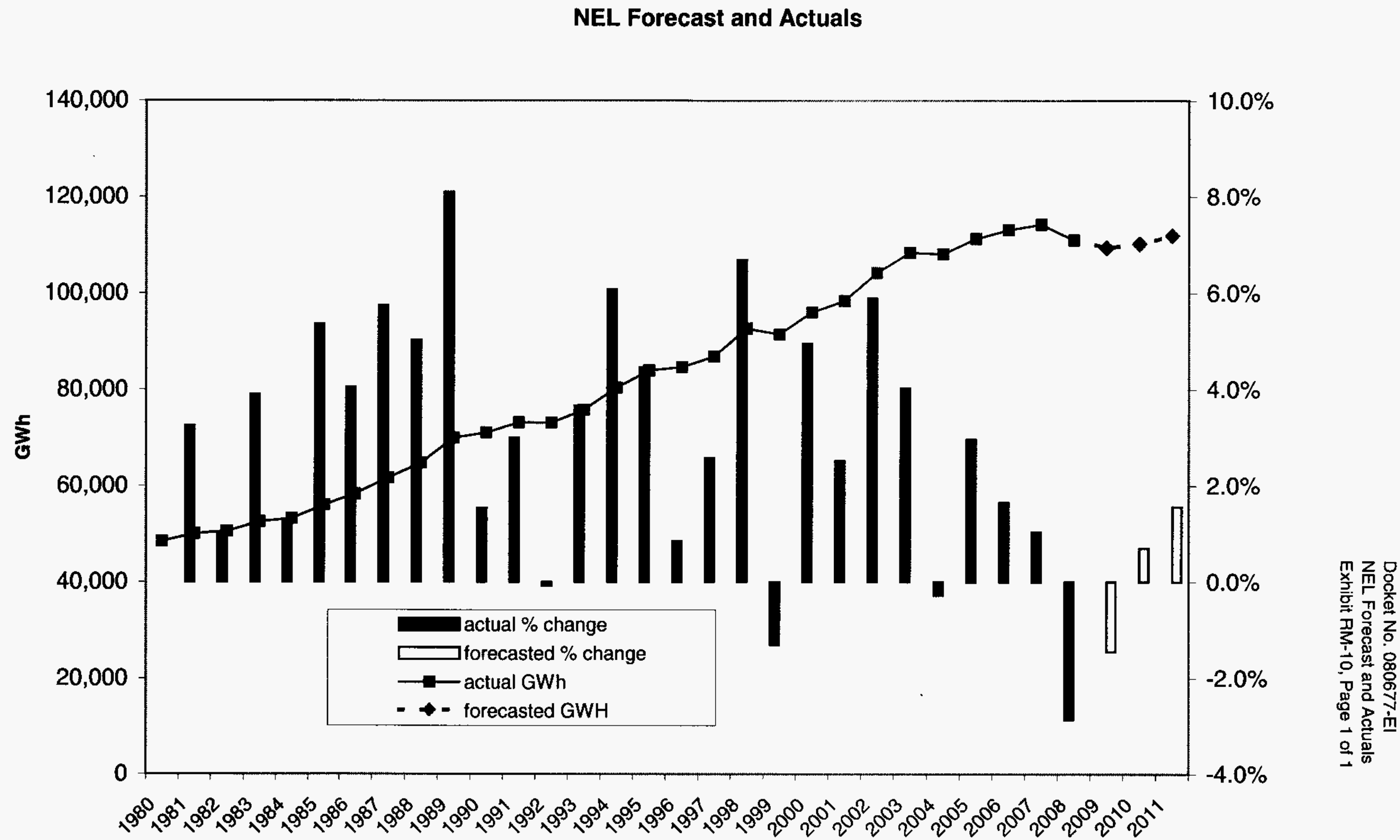
Annual Energy Use per Customer
kWh



Docket No. 080677-EI
Annual Energy Use Per Customer
Exhibit RM- 9, Page 1 of 1

THE FORECAST SHOWS THE TREND IN DECLINING ENERGY USE PER CUSTOMER CONTINUING IN 2009 FOLLOWED BY RELATIVELY STABLE USE PER CUSTOMER IN 2010.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 48
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Rosemary Morley (RM-9)
DATE 08/27/09



THE FORECAST SHOWS A DROP NEL IN 2009 FOLLOWED BY SMALL INCREASES IN 2010 AND 2011.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 49
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Rosemary Morley (RM-10)
DATE 08/27/09

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080677-EI & 090130-EI EXHIBIT 50

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS Rosemary Morley (RM-11)

DATE 08/27/09

2008 MONTHLY ACTUALS 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	4,234,068	3,604,218	3,598,528	3,779,247	4,283,255	5,282,805	5,301,896	5,331,471	5,632,133	4,805,005	3,672,851	3,703,339	53,228,815
Commercial	3,783,449	3,491,304	3,442,605	3,509,771	3,717,190	4,108,255	4,103,113	4,016,556	4,261,071	3,926,048	3,580,327	3,621,740	45,561,429
Industrial	332,838	317,152	282,857	296,408	292,756	323,011	308,290	280,430	300,916	288,124	275,331	289,109	3,587,220
Street & Highway	36,111	31,207	37,034	32,584	34,399	35,670	34,633	35,472	35,449	37,889	36,156	36,252	422,854
Other	5,750	3,526	3,602	3,498	3,487	3,342	2,394	2,229	2,462	2,465	2,280	2,359	37,394
Railroads & Railways	7,558	6,695	6,300	6,711	6,383	6,832	7,158	6,762	6,863	6,662	6,730	6,442	81,095
TOTAL JURISDICTIONAL SALES	8,399,773	7,454,102	7,370,925	7,628,219	8,337,469	9,759,915	9,757,484	9,672,919	10,238,893	9,066,193	7,573,675	7,659,241	102,918,808
Resale	70,977	70,732	75,435	83,930	82,920	94,216	95,495	97,640	97,219	84,715	77,558	62,338	993,176
TOTAL SALES	8,470,750	7,524,834	7,446,360	7,712,149	8,420,389	9,854,131	9,852,979	9,770,559	10,336,112	9,150,908	7,651,234	7,721,579	103,911,984
CUSTOMERS													
Residential	3,995,414	4,001,651	4,003,023	4,001,785	3,996,910	3,996,829	3,991,810	3,989,187	3,985,030	3,983,523	3,981,138	3,980,785	3,992,257
Commercial	498,674	499,460	499,080	499,289	500,326	500,723	501,265	501,848	501,941	502,471	502,192	501,710	500,748
Industrial	15,142	14,695	14,221	13,923	13,597	13,372	13,155	12,920	12,797	12,548	12,249	11,902	13,377
Street & Highway	3,073	3,083	3,095	3,095	3,099	3,107	3,113	3,132	3,141	3,150	3,155	3,170	3,118
Other	207	207	206	205	205	204	204	204	201	199	199	199	203
Railroads & Railways	23	23	23	23	23	23	23	23	23	23	23	23	23
TOTAL JURISDICTIONAL CUSTOMERS	4,512,533	4,519,119	4,519,648	4,518,320	4,514,160	4,514,258	4,509,570	4,507,314	4,503,133	4,501,914	4,498,956	4,497,789	4,509,726
Resale	3	3	3	3	3	3	3	3	3	3	3	3	3
TOTAL CUSTOMERS	4,512,536	4,519,122	4,519,651	4,518,323	4,514,163	4,514,261	4,509,573	4,507,317	4,503,136	4,501,917	4,498,959	4,497,792	4,509,729
USE PER CUSTOMER													
Residential	1,060	901	899	944	1,072	1,322	1,328	1,336	1,413	1,206	923	930	13,333
Commercial	7,587	6,990	6,898	7,030	7,430	8,205	8,186	8,004	8,489	7,813	7,129	7,219	90,987
Industrial	21,981	21,582	19,890	21,289	21,531	24,156	23,435	21,705	23,515	22,962	22,478	24,291	268,168
Street & Highway	11,751	10,122	11,966	10,528	11,100	11,480	11,125	11,326	11,286	12,028	11,460	11,436	135,628
Other	27,779	17,035	17,485	17,062	17,008	16,383	11,735	10,929	12,247	12,387	11,458	11,852	183,904
Railroads & Railways	328,589	291,078	273,913	291,783	277,520	297,059	311,217	293,985	298,383	289,652	292,600	280,091	3,525,870
TOTAL JURISDICTIONAL USE PER CUSTOMER	1,861	1,649	1,631	1,688	1,847	2,162	2,164	2,146	2,274	2,014	1,683	1,703	22,822
Resale	23,659,038	23,577,379	25,144,927	27,976,706	27,639,891	31,405,372	31,831,667	32,546,709	32,406,485	28,238,333	25,852,787	20,779,368	331,058,660
TOTAL USE PER CUSTOMER	1,877	1,665	1,648	1,707	1,865	2,183	2184.902872	2,168	2,295	2,033	1,701	1,717	23,042

2009 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	4,130,323	3,468,481	3,497,491	3,489,545	4,115,788	4,842,751	5,361,699	5,381,235	5,500,354	4,520,380	3,971,898	3,761,406	52,041,349
Commercial	3,453,620	3,322,308	3,421,457	3,367,760	3,712,611	3,964,249	4,160,403	4,080,752	4,232,494	3,750,863	3,707,423	3,703,695	44,877,633
Industrial	295,357	295,036	295,093	295,759	297,154	299,256	301,488	302,591	303,048	302,409	299,949	297,293	3,584,431
Street & Highway	37,920	37,405	37,468	37,118	36,933	36,798	36,585	36,564	36,233	36,315	38,515	38,368	446,222
Other	3,472	3,373	3,462	3,379	3,359	3,250	2,335	2,169	2,425	2,447	3,456	3,448	36,573
Railroads & Railways	6,462	8,981	7,349	7,364	7,359	7,825	7,900	7,480	7,747	7,452	7,415	8,048	91,381
TOTAL JURISDICTIONAL SALES	7,927,154	7,135,583	7,262,320	7,200,924	8,173,203	9,154,127	9,870,409	9,810,791	10,082,301	8,619,865	8,028,656	7,812,258	101,077,590
Resale	77,790	77,463	76,996	81,612	85,056	101,091	114,674	117,991	119,961	116,916	95,312	84,056	1,148,917
TOTAL SALES	8,004,944	7,213,046	7,339,316	7,282,536	8,258,258	9,255,218	9,985,083	9,928,782	10,202,261	8,736,781	8,123,968	7,896,314	102,226,507
CUSTOMERS													
Residential	3,994,841	4,000,974	4,002,451	4,000,158	3,997,866	3,996,663	3,989,592	3,988,999	3,986,185	3,985,374	3,990,606	3,996,362	3,994,173
Commercial	504,972	505,822	506,676	507,532	508,430	509,331	510,234	511,183	512,135	513,090	514,085	515,084	509,881
Industrial	12,526	12,522	12,518	12,514	12,513	12,513	12,512	12,521	12,530	12,539	12,552	12,565	12,527
Street & Highway	3,161	3,165	3,169	3,173	3,176	3,179	3,183	3,185	3,188	3,190	3,193	3,195	3,180
Other	198	198	198	198	198	199	199	198	198	198	197	197	198
Railroads & Railways	23	23	23	23	23	23	23	23	23	23	23	23	23
TOTAL JURISDICTIONAL CUSTOMERS	4,515,721	4,522,705	4,525,035	4,523,597	4,522,207	4,521,908	4,515,743	4,516,110	4,514,260	4,514,414	4,520,656	4,527,425	4,519,982
Resale	4	4	4	4	4	4	4	4	4	4	4	4	4
TOTAL CUSTOMERS	4,515,725	4,522,709	4,525,039	4,523,601	4,522,211	4,521,912	4,515,747	4,516,114	4,514,264	4,514,418	4,520,660	4,527,429	4,519,986
USE PER CUSTOMER													
Residential	1,034	867	874	872	1,029	1,212	1,344	1,349	1,380	1,134	995	941	13,029
Commercial	6,839	6,568	6,753	6,636	7,302	7,783	8,154	7,983	8,264	7,310	7,212	7,190	88,016
Industrial	23,579	23,561	23,573	23,634	23,747	23,916	24,096	24,167	24,186	24,117	23,897	23,661	286,133
Street & Highway	11,997	11,820	11,825	11,700	11,628	11,574	11,495	11,479	11,366	11,382	12,063	12,007	140,334
Other	17,535	17,035	17,485	17,063	16,962	16,297	11,735	10,926	12,249	12,387	17,535	17,535	184,705
Railroads & Railways	280,947	390,487	319,520	320,168	319,973	340,213	343,484	325,229	336,820	323,978	322,385	349,897	3,973,101
TOTAL JURISDICTIONAL USE PER CUSTOMER	1,755	1,578	1,605	1,592	1,807	2,024	2,186	2,172	2,233	1,909	1,776	1,726	22,362
Resale	19,447,476	19,365,695	19,249,118	20,403,016	21,263,888	25,272,647	28,668,620	29,497,824	29,990,161	29,228,959	23,827,903	21,013,976	287,229,282
TOTAL USE PER CUSTOMER	1,773	1,595	1,622	1,610	1,826	2,047	2,211	2,199	2,260	1,935	1,797	1,744	22,617

2010 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	4,242,969	3,404,335	3,442,757	3,429,560	4,043,322	4,756,140	5,282,639	5,305,529	5,422,914	4,455,862	3,916,982	3,723,874	51,426,883
Commercial	3,624,458	3,325,762	3,440,263	3,384,942	3,736,630	3,986,343	4,195,773	4,119,301	4,276,342	3,797,661	3,757,979	3,771,717	45,417,171
Industrial	295,958	295,873	296,179	297,086	298,616	300,842	303,181	304,582	305,380	305,126	302,933	300,536	3,606,295
Street & Highway	38,368	37,837	37,892	37,531	37,336	37,193	36,972	36,950	36,615	36,699	38,926	38,783	451,102
Other	3,440	3,334	3,414	3,324	3,297	3,160	2,270	2,109	2,358	2,379	3,360	3,353	35,798
Railroads & Railways	6,462	8,981	7,349	7,364	7,359	7,825	7,900	7,480	7,747	7,452	7,415	8,048	91,381
TOTAL JURISDICTIONAL SALES	8,211,655	7,076,123	7,227,855	7,159,807	8,126,560	9,091,503	9,828,736	9,775,951	10,051,356	8,605,179	8,027,595	7,846,312	101,028,630
Resale	78,703	165,059	158,777	171,513	176,254	198,137	198,684	203,533	209,795	206,224	197,103	172,900	2,136,682
TOTAL SALES	8,290,357	7,241,182	7,386,632	7,331,320	8,302,814	9,289,640	10,027,420	9,979,484	10,261,151	8,811,403	8,224,699	8,019,211	103,165,312
CUSTOMERS													
Residential	4,002,627	4,009,268	4,012,140	4,010,136	4,007,646	4,007,873	4,005,317	4,008,166	4,008,647	4,010,581	4,019,246	4,028,401	4,010,837
Commercial	516,085	517,111	518,139	519,170	520,219	521,270	522,324	523,364	524,406	525,451	526,519	527,589	521,804
Industrial	12,577	12,594	12,611	12,627	12,649	12,671	12,692	12,715	12,737	12,759	12,787	12,815	12,686
Street & Highway	3,198	3,201	3,204	3,208	3,211	3,214	3,216	3,219	3,222	3,224	3,227	3,230	3,214
Other	196	196	195	195	194	194	193	193	193	192	192	191	194
Railroads & Railways	23	23	23	23	23	23	23	23	23	23	23	23	23
TOTAL JURISDICTIONAL CUSTOMERS	4,534,707	4,542,393	4,546,312	4,545,359	4,543,942	4,545,245	4,543,766	4,547,680	4,549,227	4,552,230	4,561,993	4,572,249	4,548,759
Resale	4	4	4	4	4	4	4	4	4	4	4	4	4
TOTAL CUSTOMERS	4,534,711	4,542,397	4,546,316	4,545,363	4,543,946	4,545,249	4,543,770	4,547,684	4,549,231	4,552,234	4,561,997	4,572,253	4,548,763
USE PER CUSTOMER													
Residential	1,060	849	858	855	1,009	1,187	1,319	1,324	1,353	1,111	975	924	12,822
Commercial	7,023	6,431	6,640	6,520	7,183	7,647	8,033	7,871	8,155	7,227	7,137	7,149	87,039
Industrial	23,531	23,493	23,486	23,527	23,608	23,743	23,887	23,955	23,976	23,915	23,691	23,453	284,271
Street & Highway	11,997	11,820	11,825	11,700	11,628	11,574	11,495	11,479	11,366	11,382	12,063	12,007	140,334
Other	17,535	17,035	17,485	17,063	16,962	16,297	11,735	10,926	12,249	12,387	17,535	17,535	184,836
Railroads & Railways	280,947	390,487	319,520	320,168	319,973	340,213	343,484	325,229	336,820	323,978	322,385	349,897	3,973,101
TOTAL JURISDICTIONAL USE PER CUSTOMER	1,811	1,558	1,590	1,575	1,788	2,000	2,163	2,150	2,209	1,890	1,760	1,716	22,210
Resale	19,675,692	41,264,747	39,694,336	42,878,207	44,063,408	49,534,211	49,671,083	50,883,161	52,448,812	51,556,031	49,275,807	43,224,941	534,170,435
TOTAL USE PER CUSTOMER	1,828	1,594	1,625	1,613	1,827	2,044	2206.85	2,194	2,256	1,936	1,803	1,754	22,680

PHILIP Q HANSER **Principal**

Philip Q Hanser is a principal of *The Brattle Group* and has over twenty-five years of consulting and litigation experience in the energy industry. His expertise includes issues ranging from industry structure, market power and associated regulatory questions, to specific operational and strategic questions such as transmission pricing, generation planning, tariff strategies, fuels procurement, environmental issues, forecasting, demand-side management, and other management and financial issues. He has supported clients' efforts in insurance recovery of environmental liabilities arising from former manufactured gas plant sites, assessed liability risk in mass tort suits, and designed statistical database auditing procedures.

He has appeared as an expert witness before the U.S. Federal Energy Regulatory Commission (FERC), the California Energy Commission (CEC), the New Mexico Public Service Commission (NMPSC), the Public Service Commission of Wisconsin (PSCW), the Vermont Public Service Board (VPSB), the Public Utilities Commission of Nevada (PUCN), the Connecticut Siting Commission, the Pennsylvania Department of Environmental Protection, before arbitration panels, and in Federal and state courts. He served for six years on the American Statistical Association's Advisory Committee to the Energy Information Administration (EIA). He serves on CIGRE's (Conseil International des Grands Reseaux Electriques) Working Group C5-8, Working Group on Renewables and Energy Efficiency in a Deregulated Market. Prior to joining *The Brattle Group*, he served as the manager of the Demand-Side Management Program at the Electric Power Research Institute (EPRI). He has published widely in leading industry and economic journals. Mr. Hanser has taught at the University of the Pacific, University of California at Davis, and Columbia University, and guest lectured at the Massachusetts Institute of Technology, Stanford University, and the University of Chicago.

REPRESENTATIVE EXPERIENCE

Forecasting and Weather Normalization

- For an electric utility in the Southeast, reviewed the existing weather normalization process and diagnosed problems with weather data and regression model. Developed alternative daily and monthly normalization models, improved degree day specification, selection of weather stations, and regression specification to double prediction accuracy and improve stability of normalization process.

- For PJM, conducted a comprehensive review of its models for forecasting peak demand and re-estimated new models to validate recommendations. Individual models were developed for 18 transmission zones as well as a model for the entire PJM system.

- For a Southwestern utility, developed models for forecasting monthly sales and loads for the residential, commercial and industrial customer classes using primary data on customer loads, weather conditions and economic activity.

- For the Public Service Company of New Mexico, provided expert testimony before the Public Utilities Commission of New Mexico regarding the forecasted growth of the El Paso, Texas and Juarez, Mexico markets and their electricity requirements.

- For a Southeastern utility, developed a model for forecasting monthly demand that incorporated the impacts of its significantly declining housing market and which served the basis for its treasurer's revenue forecast.

Rate Design and Related Issues

- For Ameren/UE's Missouri subsidiary, provided expert testimony on its rate design before the Missouri Public Utility Commission. Assisted the development of company witnesses' rationale for the choice of cost of service allocation method, developed benchmarks for the rate increase against similarly situated utilities, as well for other commodities' escalations, and evaluated proposed demand-side management programs and rate options.

- For Ameren/UE's Illinois subsidiaries, provided expert testimony on the potential for gas demand-side management. The testimony discussed potential rate implications of such programs on the revenue of the utilities.

- For the Edison Electric Institute, co-authored a series of papers with regard to issues facing utilities. The reports covered the issues of fuel adjustment clauses, mitigating large rate increase impacts, and the Energy Policy Act of 2005.

- For a U.S. electric utility, assisted in the valuation of generation assets for use in its testimony on stranded costs. This included development a financial model to determine the generation assets' market value, development of a convolution algorithm to convert market scenarios into a probability distribution of asset values, and statistical analysis of the relationship of the utility's generation assets' operating costs in comparison to its competitors. The assignment also included testimony preparation, interrogatories, and rebuttals.

- For the City of Vernon submitted testimony to the FERC regarding its revenue requirements for transmission.

Analysis of Electricity Generation, Contracts, and Wholesale Markets

- For the California Department of Water Resources provided expert testimony in federal bankruptcy court with regard to the public interest standard to be applied to Calpine Corporation's rejection of its contracts. This assignment included a valuation of the contract over time through the use of a simulation model of the California market, as well as an assessment of the potential reliability implications for the California market.

- For the California Department of Water Resources and the California Attorney General's Office, provided expert testimony on damages resulting from Sempra Energy Resources breaches of its power purchase agreement in both arbitration hearings and California state court. Analyzed two years of hourly data on energy deliveries, market prices, ISO charges, and invoice charges to identify and evaluate performance violations and invoice overcharges. Assisted counsel in developing the theory of the case and provided general litigation support in preparation for and during arbitration.

- For Dominion Electric Marketing, Inc. (DEMI), provided assistance in their response to a complaint by United Illuminating (UI) regarding their wholesale supply contract. The dispute centered on the allocation of reliability must run costs between UI as a load-serving entity and DEMI as wholesale supplier.

- For the California Department of Water Resources critically reviewed the California ISO's proposed implementation of locational marginal pricing (LMP) and analyzed implications for "seller's choice" supply contracts. Developed a framework for quantifying the incremental congestion costs that ratepayers would face if suppliers financially delivered power to the lowest priced nodes; estimated potential incremental contract costs using a third party's GE-MAPS market simulations (and helped to improve their model inputs to more accurately reflect the transmission system in California). Made recommendations to the CAISO as to how to address the issue.

- Provided expert testimony in Massachusetts state court on the damages incurred by a power plant developer as a result of alleged contractual violations by a supplier for a plant constructed in ISO-NE.

- For a Florida utility, provided a confidential expert report evaluating the benefits of the power from a co-generator and its potential rate implications, and assisted in the negotiation of a co-generation contract with a large industrial customer.

- Assisted a U.S. electric utility in the preparation of a bid proposal to an industrial firm for the leasing of a new power plant. The assignment included risk analysis of the proposal, assessment of financial and rate impacts, and market assessment of competitors' potential offerings.

Resource Planning and Procurement

- For the Edison Electric Institute, co-authored a report on the general inapplicability of standard financial portfolio theory to the resource portfolios of utilities.

- For the investor-owned utilities of Wisconsin, provided testimony before the Public Service Commission of Wisconsin on cost of capital issues for use in its statewide resource planning exercise.

- For an international development bank, evaluated generation resource needs for an Eastern European country as well as a determination of alternative means to meet those generation needs. This assignment included analysis of the impact of privatization on the country's economy, its import and export sectors, and future development of electricity and gas resources.

Environment

- For an Eastern utility with substantial coal-generating facilities, provided advice with regard to maintenance procedures and risk exposure to New Source Review standards under the Clean Air Act Amendments.

- For a Western generator with substantial coal-generating facilities he has provided assistance with regard to responding to allegations by the Environmental Protection Agency of failure to comply with the New Source Review standards under the Clean Air Act Amendments.

- For Illinois Power Company, provided expert testimony in federal court on the regulatory and rate base implications of the Clean Air Act Amendments, in support of the calculation of noncompliance economic damages arising from New Source Review.

- For a gas utility, assisted in the development of potential manufactured gas liabilities for use in insurance recovery and in estimating potential recovery under a variety of insurance allocation theories and estimated the risk distribution of the estimates.

- For a gas utility, assisted in the assessment of the announcement effect of environmental liabilities on its cost of capital. This assignment included estimation of changes in market betas for pre- and post- environmental liability announcement.

Energy Efficiency, Demand-Side Management, and Renewables

- For Central Vermont Public Service, provided expert testimony on the impact of its demand-side management programs before the Vermont Public Service Board.

- For Ameren/UE's Illinois subsidiaries, provided expert testimony on the potential for gas demand-side management and resulting potential rate implications.

- For a Northeast utility developed an assessment of the potential penetration rate of microturbines. For the utility service territories under consideration, evaluated the back-up generation rates and connection charges likely to be incurred for such systems to determine customer costs and benefits.
- For a utility located in WECC procuring renewable resources, provided a system integration study for a range of renewable project proposals. Used production costing and power flow models to estimate the "deliverability" of various proposals, including estimating the LMP prices and the potential congestion costs. Ranked the proposed renewable power projects by their estimated benefits and costs, and delivered a formal presentation at the completion of the project.

- For a power marketer and developer of independent power projects in Great Britain, assisted in the preparation of comments on proposals by the UK pool regarding the role of demand-side bidding and the pricing of transmission losses.

- For a Texas utility, provided expert testimony regarding breach of contract claims made against it by an industrial participant in an energy efficiency project. Reviewed the energy efficiency impacts of program. Calculated the net present value of the project in relation to various rate options and market prices.

- For Connecticut Light and Power, provided testimony in support of an application for a Certificate of Environmental Compatibility and Public Need for the construction of a 345-kV electric transmission line and reconstruction of an existing 115-kV electric transmission line. At issue was the use of distributed resources to substitute for the proposed lines.

Analysis of Market Power

- For the California Parties, provided litigation support and testimony regarding manipulation of energy and ancillary service market prices and the outage behavior of gas fired power plants during 2000-01. The proceeding, before the Federal Energy Regulatory Commission involved Enron, Dynegy, Mirant, Reliant, Williams, and other suppliers in the U.S. and Canada. The analyses focused on the use by suppliers of generation outages to affect market prices through physical withholding, as well as the use of pricing to yield economic withholding.

- For the California Parties, provided litigation support and testimony regarding Enron's transmission and ancillary services market manipulation strategies, including 'Death Star' and 'Get Shorty.'

- For Southern California Edison, submitted testimony before the FERC describing the implications for the electricity market of the manipulation of gas market prices.

- For Sierra Pacific Resources Company, provided expert testimony before the Public Utilities Commission of Nevada and the FERC regarding the market power implications of generation asset divestiture required for the merger of Sierra Pacific Power and Nevada Power Company. Developed a Cournot market model to assess the market power implications of selling off alternative groupings of generation.

- For the Pennsylvania-New Jersey-Maryland Interconnection, LLC (PJM) co-authored annual report on the state of its markets. The report included an assessment of the market's competitiveness and potential structural deficiencies, and identified potential instances of market abuse.

- For PJM, developed an ensemble of metrics for assessing market power in its markets. The metrics included an early warning system to permit PJM interventions into market abuse at the earliest possible stage.

- For PJM, developed software for unilateral market power assessment and assisted PJM in its preliminary implementation. Its use was demonstrated with an incident involving potential market power abuse by PJM members.

RTO Design and Participation

- For Northeast Utilities provided testimony before the FERC with regard to the economics of imposing local installed capacity (LICAP) requirements on ISO-NE. Also has provided expert testimony before the FERC in support of its applications for market-based rate authority.

- For NSTAR provided testimony before the FERC on several matters including the necessity of imposing bid caps on the New England electricity market, replacement energy rates for generators when transfer capability into a transmission-constrained zone was reduced because of system upgrades, and the appropriateness of granting market-based rate authority to a generator in a transmission-constrained zone. Developed a Cournot market model to forecast the potential impact on market prices in the transmission-constrained zone that the majority of NSTAR's service territory is located.

- For Nevada Power Company, provided expert testimony before the FERC for its market-based rate authority application.

- For Otter Tail Power Company, provided an affidavit to the FERC assessing how the Midwest ISO's proposed Transmission and Energy Market Tariff would affect Otter Tail Power both operationally and financially. Based on the strategies that were pursued by some market participants during the 2001 California electricity market crisis, demonstrated the potential to pursue similar strategies in MISO and harm Otter Tail and its customers.

- For Edison Mission Energy's subsidiary Midwest Gen, provided expert testimony to the FERC for its market-based rate authority application.

- For a Midwest utility, examined the implications of differing configurations of the independent system operator on potential market power concerns. The issue particularly examined was the question of seams and how different ISO configurations affected the costs of transactions.

- Co-authored a report for the New York Independent System Operator's (NYISO) assessing the reliability implications of modifying its rules regarding installed capacity.

- Submitted testimony to the Public Utilities Commission of Texas (PUCT) regarding a proposed rule to allocate costs of procuring replacement reserves to market participants in ERCOT. The proposed rule required ERCOT to assign the majority of such costs directly to market participants who relied on ERCOT's balancing energy (*i.e.*, real-time energy) market. However, a review of the market rules and the historical evidence indicated that the majority of the procurement of replacement reserves was not caused by this behavior. The PUCT rejected the proposed cost allocation rule, and instead required ERCOT to uplift the replacement reserve costs based on the load ratio shares of market participants until the implementation of a reasonable allocation rule or the start of the Texas Nodal Market.

- For the Edison Electric Institute, authored a report on standard market design and its implications for utilities within regional transmission organizations.

Transmission

- Before staff members of the FERC, assisted in the development of a review of the implications of the restructuring in transmission assets' cost of capital.

- For a power marketer and developer of independent power projects in Great Britain, assisted in the preparation of comments on proposals by the UK pool regarding the pricing of transmission losses and the role of demand-side bidding.

- For a European transmission company, provided an analysis of the likely development of the European electricity market. Also assessed market implications for the transmission company of modifications to the transmission grid.

- For Hydro Quebec, provided expert testimony before the Regie d'Energie regarding whether a set of privately held transmission facilities constituted a looped transmission system and, thus, was subject to requests for transmission service.

Plant Performance and Strategy

- For the Keystone-Conemaugh Project Office, performed a benchmarking analysis to identify the areas in which Keystone and Conemaugh coal units were better performing or under-performing compared to other units with similar characteristics. This involved comparing the historical operational and cost performance of the Keystone and Conemaugh coal units against their peer groups; identifying the areas where the performance of the Keystone and Conemaugh coal units were above and below the average quartile of their peer groups; and developing metrics and methodologies to combine the results of individual comparisons across the operational and cost performance assessments.

- For a U.S. electric utility, assisted in the development of a legislative and regulatory strategy with regard to restructuring. This assignment included generation asset valuation in a competitive market, development of stand-alone transmission and distribution rates under cost-of-service and performance-based regulation, and estimation of stranded costs.

Other energy experience

- For the Electric Power Research Institute (EPRI), developed and directed a research program to provide electric utilities the following capabilities: marketing research, pricing and rate design, integrated resource planning, capital budgeting, environmental impacts of electric utilities and end-use technologies, load research, forecasting, and demand-side management through software tools, database development and technology development. Assisted in the development of the Load Management Strategy Testing Model (LMSTM), enhancements to the Electric Generation Expansion Analysis Model (EGEAS). Co-wrote reports on the environmental impacts of electric technologies, environmental externalities, cost-benefit analysis of evaluation of DSM programs, rate design and costing, integrated resource planning, impacts of interruptible and curtailable loads, product differentiation, activity-based costing, DSM program evaluation, and others. Served as project manager of the Edison Electric Institute (EEI), National Rural Electric Cooperatives Association (NRECA), American Public Power Association (APPA), and National Association of Regulatory Utility Commissioners (NARUC) jointly sponsored Electric Utility Rate Design Study (EURDS). Represented the Institute before various regulatory commissions, Federal agencies, and utility executives. He served on the Environmental Protection Agency's advisory committee for the Clean Air Act Amendments. He also served as the operating agent for Annex IV, Improved Methods for Integrating Demand-Side Options into Utility Resource Planning, of the International Energy Agency Agreement on Demand-Side Management.

- For a California utility, supervised short- and long-term forecasts of sales and peak demand for use in resource and corporate planning. Supervised and helped prepare forecast documentation for public hearings before the California Energy Commission and represented the utility to the Commission on the forecast. Supervised the design and implementation of long-term strategic planning and financial models, and prepared both marginal and embedded cost of service studies for the utility and assisted in their use for the design of customer rates. Evaluated the impact of energy conservation programs and legislation on long-term system resource requirements. Designed and implemented the residential survey of appliance holdings and commercial customer equipment survey.

Non-energy Related

- Submitted testimony in bankruptcy court regarding the estimation of inventory subject to reclamation by a wholesale pharmaceuticals supplier which was sold to a bankrupt retail drug chain. The retail chain failed to maintain proper inventory records and a statistical approach which used a combination of data on overall inventory and the shipment and replenishment records of the supplier was used to develop the estimate.

- Designed a statistically valid database sampling procedure for assessing the validity of insurance claims arising from mass tort actions. The database contained summary information on the claims and for each claim there was, at times, voluminous information on the individual cases. The sampling procedure was used to determine which records would be chosen and assessed the individual's claim eligibility.

- Assessed the liability risk of an insurance company that provided coverage relevant to a mass tort suit. A Markov chain model was developed to estimate the size of the potential population and then a risk model was developed to calculate potential exposure.

TESTIMONY AND REGULATORY FILINGS

Before the Pennsylvania Public Utility Commission, Docket No. P-2008-2020257, prepared testimony on behalf of Wellsboro Electric Company concerning the causes and pricing of transmission congestion, July 30, 2008.

Before the Regie De L'Energie, Prepared Affidavit on Behalf of Hydro-Quebec regarding the public availability of SIS reports performed by a transmission provider, June 19, 2008.

Before the Federal Energy Regulatory Commission, Docket No. EL08-__-000, Prepared Direct Testimony on Behalf of the City of Vernon's revised TRR filing with the FERC, April 3, 2008.

Before the Regie De L'Energie, Prepared Expert Report on Behalf of Hydro-Quebec TransEnergie to assess whether the transmission facilities owned by ELL may be considered as a "radial generator lead", March 13, 2008.

Before the American Arbitration Association, Case No. 74Y1980019606MAVI, Prepared Rebuttal Report on Behalf of the California Department of Water Resources to evaluate the reports that William Hogan, Jeffrey Tranen, and Ellen Wolfe provided on behalf of Sempra Generation, June 4, 2007.

Before the American Arbitration Association, Case No. 74Y1980019606MAVI, Prepared Expert Report on Behalf of the California Department of Water Resources to evaluate certain claims made by the California Department of Water Resources ("DWR") in its Demand for Arbitration regarding the performance of Sempra Energy Resources, now known as Sempra Generation, under the Energy Purchase Agreement between the parties, and to calculate amounts that Sempra would owe to DWR assuming liability is established, May 14, 2007.

Before the United States Bankruptcy Court, Northern District of Ohio, Eastern Division, Case Nos. 01-44007 through 01-44015, Expert Report in regard to McKesson's inventory reclamation in the Phar-Mor bankruptcy, March 9, 2007.

Before the Public Utility Commission of Texas, Docket No. 33416, Prepared Rebuttal Testimony on Behalf of Constellation New Energy, Inc.'s appeal and complaint of ERCOT decision to approve PRR 676, PRR 674 and request for expedited relief, January 11, 2007.

Before the Public Utility Commission of Texas, Docket No. 33416, Prepared Direct Testimony on Behalf of Constellation NewEnergy, Inc. to analyze and discuss the flaws and potential negative impacts of the allocation methods under Protocol Revision Request ("PRR") 676 which relates to procurement costs for Replacement Reserve Service ("RPRS") and Out of Merit Capacity, November 22, 2006.

Before the American Arbitration Association, Case No. GIC 789291, Prepared Rebuttal Report on Behalf of California Department of Water Resources vs. Sempra Energy Resources, July 11, 2006.

Before the State Office of Administrative Hearings, Prepared Expert Report on Behalf of TXU

Energy Solutions, regarding their demand-side management program and the difference between the actual and projected savings in the energy bill of University of Texas, July 7, 2006.

Before the Missouri Public Service Commission, Case No. ER-2007-0002, Prepared Direct Testimony on Behalf of Union Electric Company with regard to Ameren UE's rate design proposals, July 5, 2006.

Before the American Arbitration Association, Case No. GIC 789291, Prepared Expert Report on Behalf of California Department of Water Resources vs. Sempra Energy Resources, June 9, 2006.

Before the Superior Court of the State of California, J.C.C.P. Nos. 4221, 4224, 4226 and 4228, Prepared Declaration in support of California State Agencies' opposition to motion on shortened time and motion in support of preliminary approval of class action settlement, June 8, 2006.

Before the Superior Court of the State of California, J.C.C.P. Nos. 4221, 4224, 4226 and 4228, Prepared Declaration in support of California State Agencies' opposition to proposed publication notice, January 13, 2006.

Before the United States Bankruptcy Court, Case No. 05-60200 (BRL), Prepared Declaration on Behalf of Calpine Corporation with regard to the public interest standard for the rejection of the contract, December 30, 2005.

Before the FERC, Docket No. EL05-76-001, Prepared Direct Testimony on Behalf of Dominion Energy Marketing, Inc. (DEMI), regarding a dispute between DEMI and The United Illuminating Company as to which party is responsible for paying certain costs associated with Reliability Must-Ran agreements under a December 28, 2001 Power Supply Agreement between the two parties, December 5, 2005.

Before the American Arbitration Association, Case No. 74Y1980019304VSS, Prepared Expert Report on Behalf of California Department of Water Resources vs. Sempra Energy Resources with regard to damages from multiple contract breaches, May 2005.

Before the FERC, Docket No. EL03-180-000, Prepared Supplemental Testimony on Behalf of the California Parties with regard to Enron's circular scheduling and paper trading gaming practices, January 31, 2005.

Before the FERC, Docket No. ER96-496-010, *et al.*, Prepared Affidavit on Behalf of Northeast Utilities Service Company and affiliated companies market-based rate authorization, September 27, 2004, Revised December 9, 2004.

Before the Connecticut Siting Board, Docket 217, Prepared Testimony on Behalf of Connecticut Light and Power in support of its application for a Certificate of Environmental Compatibility and Public Need for the construction of a 345-kV electric transmission line and reconstruction of an existing 115-kV electric transmission line between Connecticut Light and Power Company's Plumtree Substation in Bethel, through the Towns of Redding, Weston, and Wilton, and to Norwalk Substation in Norwalk, Connecticut, November, 2004.

Before the FERC, Docket No. ER04-691-000, Prepared Affidavit on Behalf of Otter Tail Power Company (OTP) regarding problems that may result from the implementation of MISO's markets tariff in OTP's region, May 7, 2004.

Before the FERC, Docket No. ER03-563-030, Prepared Joint Affidavit with Judy W. Chang on Behalf of Devon Power LLC, *et al.*, March 24, 2004.

Before the FERC, Docket No. EL03-180-000, Prepared Direct Testimony on Behalf of the California Parties with regard to Enron's circular scheduling and paper trading gaming practices, February 27, 2004

Before the Commonwealth of Massachusetts, Case No. 99-6016, Prepared Expert Report on Behalf of Alstom Corporation and Black and Veatch vs. Meriden Corporation, LLC, Review of *"Value of the Meriden Power Project"*, January 9, 2004

Before the FERC, Docket No. EL03-159-000, Prepared Declaration on Behalf of The California Parties, Re: Gaming Activities Of Modesto Irrigation District, October, 2003.

Before the FERC, Docket No. ER03-118-000, Prepared Affidavit on Behalf of Otter Tail Power Company For Otter Tail Power Company, assessing how the Midwest ISO's proposed Transmission and Energy Market Tariff will affect Otter Tail Power both operationally and financially, September 15, 2003.

Before the Pennsylvania Environmental Hearing Board, New Jersey Department of Environmental Protection vs. Pennsylvania Department of Environmental Protection and Lower Mount Bethel Energy, LLC, Docket No. 2001-280-C, Prepared Expert Report on Behalf of Pennsylvania Power and Light, May 2, 2003.

Before the FERC, Docket No. EL00-95-069, Prepared Rebuttal Testimony on Behalf of Southern California Edison for the California Parties regarding manipulation of energy and ancillary service market prices and the outage behavior of gas fired power plants, March 20, 2003.

Before the FERC, Docket No. EL00-95-069, Prepared Testimony on Behalf of Southern California Edison for the California Parties regarding manipulation of energy and ancillary service market prices and the outage behavior of gas fired power plants, February 24, 2003.

Before Southern District Court of Illinois, Docket No.99-833-MBR, Prepared Expert Report for Department of Justice, Environmental Protection Agency vs. Illinois Power Company and Dynegy Midwest Generation regarding the likely rate treatment of, July 29, 2002.

Before the FERC, Docket No. ER99-3693-000, Prepared Direct Testimony on Behalf of Edison Mission Energy and Edison Mission Marketing and Trading, Inc. on behalf of Midwest Generation's application for market-based rate authority, April 1, 2002.

Before the FERC, Docket No. ER01-890-000, Prepared Rebuttal Testimony on Behalf of NSTAR on the appropriate rates for generators during transmission upgrades or enhancements requiring substantial and sustained reduction in transfer capability, September 21, 2001.

Before the FERC, Docket No. EL01-79-000, Prepared affidavit on Behalf of NSTAR, in their intervention of the granting of market-based rate authority to Sithe, May 2001.

Before the FERC and the Public Utilities Commission of Nevada, Docket No. EC0-173-000, Prepared Affidavit on Behalf of Sierra Pacific Resources Company, regarding the market power implication of generation asset divestiture required for the merger of Sierra Pacific Power and Nevada Power Company, February 23, 2001.

Before the California Energy Commission, Prepared Expert Report on Behalf of Calpine Corporation; Socioeconomic Resources: Economic Benefits of the Metcalf Energy Center, October 27, 2000.

Before the FERC, Docket No. EL00-83-000, Prepared Affidavit on Behalf of NSTAR with regard to the necessity of imposing bid caps on the New England electricity market, June 23, 2000.

Before the FERC, Docket No. ER99-2338-001, Prepared Direct Testimony on Behalf of Nevada Power Company in support of the divestiture of its generation assets, June 24, 1999.

Before the FERC, Docket No. ER99-2338-001, Prepared Direct Testimony on Behalf of Nevada Power Company in support of the divestiture of its generation assets, March 30, 1999.
Before the Vermont Public Service Board, Docket No. 6018, Prepared Rebuttal Testimony on Behalf of Central Vermont Public Service Corporation on the impact of its demand-side management programs, April 10, 1998.

Before the New Mexico Public Utility Commission, Case No. 2769, Prepared Direct Testimony prepared on Behalf of the Public Service Company of New Mexico regarding forecasted growth of the El Paso and Juarez, Mexico markets, 1997.

Before the Public Service Commission of Wisconsin, Docket No. 05-EP-7, Prepared Direct Testimony on Behalf of investor-owned utilities of Wisconsin on the utilities cost of capital, May 8, 1995.

Before the FERC, Docket No. RP95-363-015, Prepared Affidavit on Behalf of Southern California Edison describing the implications for the electricity market of the manipulation of gas market prices.

ACADEMIC HISTORY

Guest Lecturer, Energy Laboratory Short Courses, Massachusetts Institute of Technology, Cambridge, MA	1997-1998
Visiting Lecturer, Department of Economics, University of California, Davis; Davis, CA	1981-1982
Assistant Professor, Departments of Economics and Mathematics, University of the Pacific, Stockton, CA	1975-1980
Ph.D. Candidacy Requirements Completed, Columbia University, NY	1975
Phil.M. (Economics and Mathematical Statistics) Columbia University	1975
A.B. (Economics and Mathematics) The Florida State University, FL	1971
Time Series and Econometric Forecasting, University of California at Berkeley Engineering Extension Course	September 1979
Data Analysis and Regression, American Statistical Association Short Course, San Diego, CA	August 1978

PROFESSIONAL MEMBERSHIPS

American Statistical Association,	1974-current
Member of Committee on Energy Statistics,	1993-1999
Institute of Electrical and Electronics Engineers,	1986-current
Association of Energy Service Professionals, Board Member,	1991-1995
Journal of ADSMP, Editor,	1995
American Economic Association,	

HONORS

Teaching Incentive Award, University of the Pacific	1979
Teaching Assistantship in Econometrics, Columbia University	1974

National Science Foundation Research Traineeship	1972 - 1974
Undergraduate and Graduate Research Assistantships, Florida State University	1968 - 1972
Omicron Delta Epsilon, Economics Honor Society	1971

PUBLICATIONS AND PRESENTED PAPERS

"Utility Supply Portfolio Diversity Requirements" (with Frank Graves), *The Electricity Journal*, Vol. 20, Issue 5, June 2007.

"Electric Utility Automatic Adjustment Clauses Revisited: Why They Are Needed More Than Ever" (with Frank Graves and Greg Basheda), *The Electricity Journal*, Vol. 20, Issue 5, June 2007.

"Rate Shock Relief" (with Frank Graves and Greg Basheda), *Electric Perspectives*, May/June 2007.

"Rate Shock Mitigation" (with Frank Graves and Greg Basheda), prepared for Edison Electric Institute, May 2007.

"Wire We Here? Coal in the West," Law Seminars International, Coal in the West Conference, Denver, Colorado, March 30, 2007.
"Electric Utility Automatic Adjustment Clauses: Benefits and Design Considerations" (with Frank Graves and Greg Basheda), Edison Electric Institute, August 2006.

"Can Wind Work In An LMP Market?" (with Serena Hesmondhalgh and Dan Harris), *Natural Gas & Electricity*, November 2005.

"The CAISO'S Physical Validation Settlement Service: A Useful Tool for All LMP-Based Markets" (with Jared S. des Rosiers, Metin Celebi, Joseph B. Wharton), *The Electricity Journal*, September 2005.

"Does SMD Need a New Generation of Market Models? Or How I Learned to Stop Worrying and Enjoy Carrying a Pocket Protector," SMD Conference, Washington, D.C., December 5, 2002.

"A Summary of FERC's Standard Market Design NOPR," Edison Electric Institute, August 2002.

"Standard Market Design in the Electric Market: Some Cautionary Thoughts," SMD Conference, May 10, 2002, Chicago, Illinois.

"The Design of Tests for Horizontal Market Power in Market-Based Rate Proceedings" (with James Bohn and Metin Celebi), *The Electricity Journal*, May 2002.

"The State of Performance-Based Regulation in the U.S. Electric Industry" (with D.E.M. Sappington, J.P. Pfeifenberger, and G.N. Basheda), *The Electricity Journal*, October 2001.

"Deregulation and Monitoring of Electric Power Markets" (with R.L.Earle and J.D. Reitzes), *The Electricity Journal*, October 2000.

"Shortening the NYISO's Installed Capacity Procurement Period: Assessment of Reliability Impacts," NYISO, May 2000.

"PJM Market Competition Evaluation White Paper," (with Frank C. Graves), prepared for PJM, L.L.C., October 1998.

"Lessons from the First Year of Competition in the California Electricity Market" (with R.L.Earle, W.C. Johnson, and J.D. Reitzes), *The Electricity Journal*, October 1999.

Comments to the FERC concerning Regional Transmission Organizations Notice of Proposed Rule Making, RM99-2, (with Peter Fox-Penner), September 17, 1999.

"In What Shape is Your ISO?" (with J.P. Pfeifenberger, G.M. Basheda and P.S. Fox-Penner), *The Electricity Journal*, Vol. 11, No. 6, July 1998.

"What's in the Cards for Distributed Resources?" (with J. P. Pfeifenberger and P.R. Ammann), in Special Issue of *The Energy Journal*, *Distributed Resources: Towards a New Paradigm of the Electricity Business*, January 1998.

"One-Part Markets for Electric Power: Ensuring the Benefits of Competition" (with F.C. Graves, E.G. Read, and R.L. Earle), in *Power Systems Restructuring: Engineering and Economics*, ed. M. Ilic, F. Galiana, and L. Fink, (Boston, MA: Kluwer Academic Publishers, 1998)

"Power Market Price Forecasting: Pitfalls and Unresolved Issues" (with R.L. Earle and F.C. Graves), forthcoming in *The Energy Journal.*

Ten EPRI reports and approximately 20 articles in EPRI Reports and Conference Proceedings.

"Insurance Recovery for Manufactured Gas Plant Liabilities" (with G.S. Koch and K.T. Wise), *Public Utilities Fortnightly*, April 1997.

"Real-Time Pricing - Restructuring's Big Bang?" (with J.B. Wharton and P. Fox-Penner), *Public Utilities Fortnightly*, March 1997.

"Load Impact of Interruptible and Curtailable Rate Programs" (with D.W. Caves, J.A Herriges, and R.J. Windle), *IEEE Transactions on Power Systems*, Vol. 3, No. 4, November 1988.

"Estimating Hourly Electric Load with Generalized Least Squares Procedures" (With N. Toyama and C.K. Woo.), *The Energy Journal*, April 1986.

"Transfer Function Estimation Using TARIMA," *SAS User's Group International, 1982 Proceedings*. Cary, North Carolina: SAS Institute. Inc., 1982.

"Invited Editorial Response to Behavioral Community Psychology: Integrations and Commitments," by Richard Winett, *The Behavior Therapist* 4(5), Convention, 1981.
Statistics Through Laboratory Experiences (with D. Christianson and D. Hughes), Stockton, CA: University of the Pacific 1976-1977.
"Unsolved Advanced Problem," *American Mathematical Monthly*, May 1975.

"Multiattribute Utility Theory and Earthquake Mitigation Policy" (with T. Munroe), Western Economic Association Conference, June 1978.

"Introduction to Multivariate Data Analysis Techniques," Bureau of Applied Social Research, Columbia University, New York, NY, 1973.

Exhibit PQH-2

FPL's Monthly NEL and Total Customer Model Descriptions

1- Total Customer Model

$$Total\_Customer_t = \beta_0 + \beta_1 FL\_POPULATION_t + \beta_2 JAN + \beta_3 FEB + \beta_4 MARCH$$
$$+ \beta_4 APRIL + \beta_5 JUNE + \beta_6 JULY + \beta_7 AUG + \beta_8 SEP + \beta_9 OCT + \beta_{10} NOV + u_t$$

where $u_t = \rho u_{t-1} + \delta u_{t-12} + \rho\delta u_{t-13} + \varepsilon_t$ and ε_t is a normally distributed error.

2- Monthly NEL model

$$NEL\_per\_Customer_t = \alpha_0 + \alpha_1 \mathrm{Re}al\_PRICE_t + \alpha_2 HDH_t + \alpha_3 CDH_t +$$
$$\alpha_4 FL\_INCOME + \alpha_5 FEB + \alpha_6 MARCH 2003 + u_t$$

where $u_t = \rho u_{t-1} + \varepsilon_t$ and ε_t is a normally distributed error.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 52
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Philip Q. Hanser (PQH-2)
DATE 08/27/09

MFRs AND SCHEDULES SPONSORED IN WHOLE OR IN PART BY ROBERT E. BARRETT, JR.

SOLE SPONSORSHIP:

MFR	TITLE
B-03 Prior	13 MONTH AVERAGE BALANCE SHEET - SYSTEM BASIS
B-03 Subsequent	13 MONTH AVERAGE BALANCE SHEET - SYSTEM BASIS
B-03 Test	13 MONTH AVERAGE BALANCE SHEET - SYSTEM BASIS
B-05 Subsequent	DETAIL OF CHANGES IN RATE BASE
B-05 Test & Prior	DETAIL OF CHANGES IN RATE BASE
B-07 Subsequent	PLANT BALANCES BY ACCOUNT AND SUB ACCOUNT
B-07 Test	PLANT BALANCES BY ACCOUNT AND SUB ACCOUNT
B-08 Subsequent	MONTHLY PLANT BALANCES TEST YEAR-13 MONTHS
B-08 Test	MONTHLY PLANT BALANCES TEST YEAR-13 MONTHS
B-09 Subsequent	DEPRECIATION RESERVE BALANCES BY ACCOUNT AND SUB ACCOUNT
B-09 Test	DEPRECIATION RESERVE BALANCES BY ACCOUNT AND SUB ACCOUNT
B-10 WCEC 3 Adj '11	MONTHLY RESERVE BALANCES TEST YEAR-13 MONTHS
B-10 Subsequent	MONTHLY RESERVE BALANCES TEST YEAR-13 MONTHS
B-10 Test	MONTHLY RESERVE BALANCES TEST YEAR-13 MONTHS
B-11 Subsequent	CAPITAL ADDITIONS AND RETIREMENTS
B-11 Test Prior Historic	CAPITAL ADDITIONS AND RETIREMENTS
B-14 Subsequent	EARNINGS TEST
B-14 Test	EARNINGS TEST
B-21 Subsequent	ACCUMULATED PROVISION ACCOUNTS - 228.1, 228.2 AND 228.4
B-21 Test	ACCUMULATED PROVISION ACCOUNTS - 228.1, 228.2 AND 228.4
C-19 Subsequent	AMORTIZATION/ RECOVERY SCHEDULE - 12 MONTHS
C-19 Test	AMORTIZATION/ RECOVERY SCHEDULE - 12 MONTHS
C-20 WCEC 3 Adj '11	TAXES OTHER THAN INCOME TAXES
C-20 Prior	TAXES OTHER THAN INCOME TAXES
C-20 Subsequent	TAXES OTHER THAN INCOME TAXES
C-20 Test	TAXES OTHER THAN INCOME TAXES

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 53
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Robert E. Barrett, Jr. (REB-1)
DATE 08/28/09

MFRs AND SCHEDULES SPONSORED IN WHOLE OR IN PART BY ROBERT E. BARRETT, JR.

JOINT OR CO-SPONSORSHIP:

MFR	TITLE
B-06 WCEC 3 Adj '11	JURSIDICTIONAL SEPARATION FACTORS - RATE BASE
B-06 Subsequent	JURSIDICTIONAL SEPARATION FACTORS - RATE BASE
B-06 Test	JURSIDICTIONAL SEPARATION FACTORS - RATE BASE
B-08 WCEC 3 Adj '11	MONTHLY PLANT BALANCES TEST YEAR-13 MONTHS
B-12 Prior	NET PRODUCTION PLANT ADDITIONS
B-12 Subsequent	NET PRODUCTION PLANT ADDITIONS
B-12 Test	NET PRODUCTION PLANT ADDITIONS
B-13 Subsequent	CONSTRUCTION WORK IN PROGRESS
B-13 Test	CONSTRUCTION WORK IN PROGRESS
B-16 Prior	NUCLEAR FUEL BALANCES
B-16 Subsequent	NUCLEAR FUEL BALANCES
B-16 Test	NUCLEAR FUEL BALANCES
B-17 Subsequent	WORKING CAPITAL - 13 MONTH AVG
B-17 Test & Prior	WORKING CAPITAL - 13 MONTH AVG
B-22 Subsequent	TOTAL ACCUMULATED DEFERRED INCOME TAXES
B-22 Test Prior Historic	TOTAL ACCUMULATED DEFERRED INCOME TAXES
B-23 Subsequent	INVESTMENT TAX CREDITS-ANNUAL ANALYSIS
B-23 Test Prior Historic	INVESTMENT TAX CREDITS-ANNUAL ANALYSIS
C-04 WCEC 3 Adj '11	JURISDICTIONAL SEPARATION FACTORS - NET OPERATING INCOME
C-04 Subsequent	JURISDICTIONAL SEPARATION FACTORS - NET OPERATING INCOME
C-04 Test	JURISDICTIONAL SEPARATION FACTORS - NET OPERATING INCOME
C-06 Subsequent	BUDGETED VERSUS ACTUAL OPERATING REVENUES AND EXPENSES
C-06 Test Prior Historic	BUDGETED VERSUS ACTUAL OPERATING REVENUES AND EXPENSES
C-08 Subsequent	DETAIL OF CHANGES IN EXPENSES
C-08 Test & Prior	DETAIL OF CHANGES IN EXPENSES
C-10 Subsequent	DETAIL OF RATE CASE EXPENSES FOR OUTSIDE CONSULTANTS
C-10 Test	DETAIL OF RATE CASE EXPENSES FOR OUTSIDE CONSULTANTS

MFRs AND SCHEDULES SPONSORED IN WHOLE OR IN PART BY ROBERT E. BARRETT, JR.

JOINT OR CO-SPONSORSHIP (Continued):

MFR	TITLE
C-12 Subsequent	ADMINISTRATIVE EXPENSES
C-12 Test & Historic	ADMINISTRATIVE EXPENSES
C-15 Subsequent	INDUSTRY ASSOCIATION DUES
C-15 Test	INDUSTRY ASSOCIATION DUES
C-21 Subsequent	REVENUE TAXES
C-21 Test Prior Historic	REVENUE TAXES
C-23 WCEC 3 Adj '11	INTEREST IN TAX EXPENSE CALCULATION
C-23 Subsequent	INTEREST IN TAX EXPENSE CALCULATION
C-23 Test & Historic	INTEREST IN TAX EXPENSE CALCULATION
C-29 Subsequent	GAINS AND LOSSES ON DISPOSITION OF PLANT AND PROPERTY
C-29 Test Prior Historic	GAINS AND LOSSES ON DISPOSITION OF PLANT AND PROPERTY
C-33 Subsequent	PERFORMANCE INDICES
C-33 Test Prior Historic	PERFORMANCE INDICES
C-36 Test Prior Historic	NON-FUEL OPERATION AND MAINTENANCE EXPENSE COMPARED TO CPI
C-36 Subsequent	NON-FUEL OPERATION AND MAINTENANCE EXPENSE COMPARED TO CPI
C-37 Subsequent	O&M BENCHMARK COMPARISON BY FUNCTION
C-37 Test	O&M BENCHMARK COMPARISON BY FUNCTION
C-42 Subsequent	HEDGING COSTS
C-42 Test Prior Historic	HEDGING COSTS
D-01a Prior	COST OF CAPITAL - 13 MONTH AVG
D-01a Subsequent	COST OF CAPITAL - 13 MONTH AVG
D-01a Test	COST OF CAPITAL - 13 MONTH AVG
F-05 Subsequent	FORECASTING MODELS
F-05 Test	FORECASTING MODELS
F-08 Subsequent	ASSUMPTIONS
F-08 Test	ASSUMPTIONS

MFRs AND SCHEDULES SPONSORED IN WHOLE OR IN PART BY ROBERT E. BARRETT, JR.

2009 SUPPLEMENTAL SCHEDULES SPONSORED OR CO-SPONSORED:

SOLE SPONSORSHIP:

MFR	TITLE
B-05 2009 Supplemental MFRs	DETAIL OF CHANGES IN RATE BASE
B-07 2009 Supplemental MFRs	PLANT BALANCES BY ACCOUNT AND SUB ACCOUNT
B-08 2009 Supplemental MFRs	MONTHLY PLANT BALANCES TEST YEAR-13 MONTHS
B-09 2009 Supplemental MFRs	DEPRECIATION RESERVE BALANCES BY ACCOUNT AND SUB ACCOUNT
B-10 2009 Supplemental MFRs	MONTHLY RESERVE BALANCES TEST YEAR-13 MONTHS
B-14 2009 Supplemental MFRs	EARNINGS TEST
B-21 2009 Supplemental MFRs	ACCUMULATED PROVISION ACCOUNTS - 228.1, 228.2 AND 228.4
B-11 2009 Supplemental MFRs	CAPITAL ADDITIONS AND RETIREMENTS

JOINT OR CO-SPONSORSHIP:

MFR	TITLE
B-06 2009 Supplemental MFRs	JURSIDICTIONAL SEPARATION FACTORS - RATE BASE
B-13 2009 Supplemental MFRs	CONSTRUCTION WORK IN PROGRESS
C-04 2009 Supplemental MFRs	JURISDICTIONAL SEPARATION FACTORS - NET OPERATING INCOME
C-10 2009 Supplemental MFRs	DETAIL OF RATE CASE EXPENSES FOR OUTSIDE CONSULTANTS
C-12 2009 Supplemental MFRs	ADMINISTRATIVE EXPENSES
C-13 2009 Supplemental MFRs	MISCELLANEOUS GENERAL EXPENSES
C-15 2009 Supplemental MFRs	INDUSTRY ASSOCIATION DUES
C-23 2009 Supplemental MFRs	INTEREST IN TAX EXPENSE CALCULATION

**MFRs AND SCHEDULES SPONSORED IN WHOLE OR IN PART
BY ROBERT E. BARRETT, JR.**

2009 SUPPLEMENTAL SCHEDULES SPONSORED OR CO-SPONSORED:

JOINT OR CO-SPONSORSHIP (Continued):

MFR	**TITLE**
C-37 2009 Supplemental MFRs	O&M BENCHMARK COMPARISON BY FUNCTION
F-05 2009 Supplemental MFRs	FORECASTING MODELS
F-08 2009 Supplemental MFRs	ASSUMPTIONS

Florida Power & Light Company

2009 Planning Process

Guideline

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 54
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Robert E. Barrett, Jr. (REB-2)
DATE 08/28/09

Contents

Florida Power & Light Company

2009 Planning Process

Guideline

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Section 1

General Instructions for Developing Business Plans, Budgets and Presentation

2009 Planning Process Calendar

Item #	Date	Day	Deliverable	Comments
1	28-Apr	Mon	Planning assumptions issued.	• Provided to all business units by Corporate Budgets.
2	21-May	Wed	2009 Planning Process Guideline issued.	• Provided to all business units by Corporate Budgets.
3	16-Jun	Mon	Presentation materials for the Jun 20th Strategic Planning Meeting and updated R-Schedules due to Corporate Budgets.	• Applies to all business units. • See requirements in Section 1, Page 7.
4	20-Jun	Fri	**Strategic Planning Meeting** Business units present to Budget Review Committee.	• Applies to certain business units. • See requirements in Section 1, Page 7.
5	7-Jul	Mon	Presentation materials for the July Budget Review Meeting with A. Olivera (date to be determined) and updated R-Schedules due to Corporate Budgets.	• Applies to all business units. • See requirements in Section 1, Page 8.
6	11-Jul	Fri	**Budget Review Meeting** Business units present to Budget Review Committee.	• Applies to all business units. • See requirements in Section 1, Page 8.
7	28-Jul	Mon	Presentation materials for the Aug1st Budget Review Meeting with J. Robo and updated R-Schedules due to Corporate Budgets.	• Applies to all business units. • See requirements in Section 1, Pages 8-9.
8	1-Aug	Fri	**Budget Review Meeting** Business units present to Budget Review Committee.	• Applies to all business units. • See requirements in Section 1, Pages 8-9.
9	20-Aug	Wed	Presentation materials for the Aug27th Final Budget Review Meeting and updated R-Schedules due to Corporate Budgets.	• Applies to all business units. • See requirements in Section 1, Page 9.
10	27-Aug	Wed	**Final Budget Review Meeting** Business units present to Budget Review Committee.	• Applies to certain business units. • See requirements in Section 1, Page 9.
11	3-Sep	Wed	**Data Submissions due to Corporate Budgets:** • Finalized R-Schedules • Supplemental Schedules • Performance Measures • Five Year Capital Forecast • Detail budgets for Aug – Dec 2008 • Detail budgets Jan – Dec for 2009, 2010 and 2011 • Detail budgets include: O&M base, O&M clauses, Non-clause fuel, Below the Line, Revenue Enhancement, Capital base, Capital clauses, Work force	• Applies to all business units. • See requirements in Section 2.

Budget Review Committee

The Budget Review Committee for the 2009 planning cycle will include the following individuals:

- FPL Group Chairman & Chief Executive Officer – Lew Hay (1)
- FPL Group President & Chief Operating Officer – Jim Robo (2)
- FPL President – Armando Olivera (3)
- FPL Group Senior Vice President Finance and Chief Financial Officer – Armando Pimentel (3)
- FPL Vice President Accounting and Chief Accounting Officer – Mike Davis (3)
- FPL Vice President Finance – Bob Barrett (3)
- FPL Group Senior Vice President Strategy, Policy and Business Process Improvement – Chris Bennett (3)

(1) August 27th meeting only
(2) August 1st and August 27th meetings only
(3) June 20th, July TBD, August 1st, and August 27th meetings

Business Plan Development

This section provides the requirements for the development of business plans.

All business units are required to prepare a business plan and submit the plan to Corporate Budgets (see Calendar Items 3 through 10, Page 1).

The business plan must contain the following sections:

1. Alignment with Corporate and Business Unit Priorities

The purpose of this section is to show how the business unit's plans support both corporate and business unit priorities. The corporate priorities are the Strategic Imperatives provided at the end of Section 1 (Section 1 - Page 11).

List each of the priorities supported by your unit, using a format similar to the example below. Next, identify the related critical success factor(s). Then list those elements of your business plan that support the listed priority and success factor(s). Business plan elements may include an ongoing activity, a specific project, an incremental effort, the achievement of a specific target or objective, etc. Next to each business plan element, list the driver(s) that influence the identified business plan element.

Transmission Business Unit			
Corp / Unit Priority	**Critical Success Factors**	**Business Plan Element**	**Drivers**
Provide excellent customer service	Improve reliability and outage management	- Maintain reliability - Meet FERC/NERC standards - Meet FERC Transmission req'ts for wholesale customers - Deploy more digital relays	- Availability of O&M and capital resources - Compliance with FERC, NERC, FPSC, and FRCC - Emerging issues from aging infrastructure

2. External Business Scan

The purpose of this section is to provide an assessment of external influences on your business plan. Include an analysis that identifies relevant business, regulatory, political, and social issues that may impact your plan, either favorably or unfavorably. Include a discussion of how the business unit plans to leverage favorable and counteract unfavorable external influences.

3. Assessment of Business Unit Capabilities

The purpose of this section is to evaluate your business unit's strengths and weaknesses, and to provide an assessment of your unit's ability to carry out the business plan. Include an analysis that identifies any gaps in resources, processes, skills, etc., and explains how the gaps will be addressed.

Review the external business scan (item 2), and consider any opportunities or threats that will impact your ability to execute your business plan.

4. Historic Performance and Benchmarking Analysis

The purpose of this section is to explain performance measure trends over time and relative to the performance of comparable business entities.

Provide an analysis of your unit's historical performance for relevant performance measures. Include at least five years of performance if the data is available. Performance measures should be both financial (cost) and operational (quality).

Provide benchmarking comparisons for each performance measure where the data is available. Indicate the entry point for the top quartile of the benchmarked group. If your unit's performance is below the top quartile entry point, provide an analysis of how the gap can be closed, including an estimate of resources and time required.

5. Cost and Performance

<u>Base Scenario:</u>

The purpose of this section is to identify the base resource requirements needed to support your key activities and processes and the associated indicators used to measure performance.

List key activities and processes that represent the core business functions of your business unit. The items listed should be consistent with how the business unit is managed. The identification of key activities and processes is subjective. Apply judgment to limit the list to between <u>five</u> and <u>seven</u> items if possible.

For each activity and process identified, provide the corresponding resource requirements and performance measures, using a format similar to the following example.

Activity / Process	Performance Measure	Resource Type	2006 Actual	2007 Actual	2008 Budget	May 2008 YTD	2008 Estimate	2009 Request	2010 Forecast	2011 Forecast
Total		Base O&M	$35	$38	$40	$16	$38	$42	$43	$45
		ECCR O&M	$2	$2	$2	$1	$2	$3	$3	$3
		Below-the-Line	$1	$1	$1	$0	$1	$1	$2	$2
		Base Capital	$8	$10	$12	$6	$11	$12	$13	$14
		ECRC Capital	$0	$2	$3	$1	$3	$6	$5	$6
		FPL Emps	260.0	280.0	280.0	263.0	270.0	280.0	292.0	295.0
#1	A	Base O&M	$20	$21	$22	$9	$21	$23	$23	$24
		Base Capital	$0	$2	$3	$1	$2	$3	$3	$4
		ECRC Capital	$0	$2	$3	$1	$3	$6	$5	$6
		FPL Emps	100.0	110.0	110.0	102.0	105.0	110.0	112.0	115.0
#2	A	Base O&M	$10	$11	$12	$5	$11	$12	$13	$13
		ECCR O&M	$2	$2	$2	$1	$2	$3	$3	$3
	B	Base Capital	$8	$8	$9	$4	$9	$9	$10	$10
		FPL Emps	80.0	85.0	85.0	77.0	80.0	85.0	90.0	90.0
#3	C	Base O&M	$5	$6	$6	$3	$6	$7	$7	$8
		Below-the-Line	$1	$1	$1	$0	$1	$1	$2	$2
		Base Capital	$0	$0	$0	$0	$0	$0	$0	$0
		FPL Emps	80.0	85.0	85.0	84.0	85.0	85.0	90.0	90.0

For each activity / process identified, include operating expenditures, capital expenditures, and FPL head count for the following periods:

- Two years of history - 2006 and 2007
- Current year budget - 2008
- Year to date actual - 2008
- Current year estimate - 2008
- Budget year request - 2009
- Two forecasted years - 2010 and 2011

Include one or more performance measures per activity / process as appropriate.

Note, O&M and capital expenditures must be stratified into each of the following categories that apply to the unit's resource requirements:

<u>Operating Expenditures</u>

- Base O&M
- ECCR O&M
- ECRC O&M
- Fuel Clause
- Capacity Clause
- Non-clause Fuel
- Below the Line
- Revenue Enhancement Expenses

<u>Capital Expenditures</u>

- Base (Net)
- ECCR
- ECRC
- Deferred Expenditures (Net)

Alternate Scenarios:

The purpose of this section is to identify alternative strategies for the accomplishment of the key activities and processes.

Propose alternative levels of spending (up-list / down-list) and show how each alternative impacts the performance measures. Provide a balanced analysis of both the favorable and the unfavorable outcomes associated with each alternative.

Business Plan Presentations

For this year's planning cycle, four meetings will be conducted for the business units to present their business plans to executive management.

1. Strategic Planning Meeting

In preparation for the Strategic Planning Meeting, all business units must submit business plan presentations to Corporate Budgets by Monday, June 16th (see Calendar Item 3).

The following business units are required to make a formal business plan presentation to the Budget Review Committee on Friday, June 20th (see Calendar Item 4). Specific times for each business unit will be communicated later.

- Nuclear
- Power Generation
- Distribution
- Transmission
- Customer Service
- Information Management
- Engineering & Construction / Corporate Services
- Project Development
- Human Resources

The business plans, of business units not presenting, will be summarized by Corporate Budgets for review by the committee.

The purpose of this meeting is to ensure appropriate business unit support for corporate and business unit priorities, identify external influences, discuss business unit capabilities, review performance trends, and provide senior management with alternatives for the deployment of limited resources.

Presentations should focus primarily on items 1 through 5 of the Business Plan Development section of this guideline. In particular, propose alternative levels of spending and show how each alternative impacts the performance measures. Provide a balanced analysis of both the favorable and the unfavorable outcomes associated with each alternative. Also, identify and discuss internal and external business factors that can influence the outcome of key performance measures and their impact on O&M, capital and workforce resources.

The Budget Review Committee may develop a list of questions / issues to be addressed at the Budget Review Meeting in July. The list of questions / issues will be communicated directly to each business unit.

2. Budget Review Meeting – July (date to be determined)

In preparation for this Budget Review Meeting, all business units must submit updated business plan presentations to Corporate Budgets by the date to be determined in July (see Calendar Item 5).

All business units are required to make a formal business plan presentation to the Budget Review Committee, led by Armando Olivera on the date to be determined in July (see Calendar Item 6). Specific times for each business unit will be communicated later.

For this meeting, presentations should focus primarily on items 4 and 5 of the Business Plan Development section of this guideline, and should reflect any changes resulting from the June 20th review meeting. Additional guidance on the development of presentations may be provided closer to the meeting date.

The Budget Review Committee may develop a list of questions / issues to be addressed at the Final Budget Review Meeting on August 1st. The list of questions / issues will be communicated directly to each business unit

3. Budget Review Meeting – August 1st

In preparation for this Budget Review Meeting, all business units must submit updated business plan presentations to Corporate Budgets by Monday, July 28th (see Calendar Item 7).

All business units are required to make a formal business plan presentation to the Budget Review Committee, led by Jim Robo, on Friday, August 1st (see Calendar Item 8). Specific times for each business unit will be communicated later.

For this meeting, presentations should focus primarily on items 4 and 5 of the Business Plan Development section of this guideline, and should reflect any changes resulting from the July review meeting. Additional guidance on the development of presentations may be provided closer to the meeting date.

Following the August 1st Budget Review Meeting, the FPL President will approve a base case scenario for each business unit. This will be the base case for the business plan presentation to the Budget Review Committee on August 27th (see Calendar Items 9 and 10) and the data submissions due to Corporate Budgets on September 3rd (see Calendar Item 11). An approved base case will be communicated directly to each business unit.

The Budget Review Committee may develop a list of questions / issues to be addressed at the Final Budget Review Meeting on August 27th. The list of questions / issues will be communicated directly to each business unit.

4. Final Budget Review Meeting

In preparation for the Final Budget Review Meeting, all business units must submit updated business plans to Corporate Budgets by Wednesday, August 20th (see Calendar Item 9).

The following business units are required to make a formal business plan presentation to the Budget Review Committee on Wednesday, August 27th (see Calendar Item 10). Specific times for each business unit will be communicated later.

- Nuclear
- Power Generation
- Distribution
- Transmission
- Customer Service
- Information Management
- Engineering & Construction / Corporate Services
- Project Development
- Human Resources

The business plans, for business units not presenting, will be summarized by Corporate Budgets for review by the committee.

The purpose of this meeting is to allow management to make final trade-offs between business units and to finalize business unit resource and performance targets. Presentations should focus primarily on items 4 and 5 of the Business Plan Development section of this guideline, and should reflect any changes resulting from the August 1st meeting. Additional guidance on the development of presentations may be provided closer to the meeting date.

Overview of Data Submissions

This section provides an overview of the requirements for final data submissions. All business units are required to provide the following data schedules to Corporate Budgets by Wednesday, September 3rd (see Calendar Item 11).

- **Resource Summary** (R-Schedule*) that includes:
  - estimated expenditures and work force for the current year
  - requested expenditure and work force for the budget year
  - projected expenditures and work force for two projected years

- **Supplemental Schedules** that include:
  - charges to other business units
  - charges to and from affiliated companies

- **Detail Budgets** that include:
  - remaining monthly cash flows for the current year (Aug – Dec)
  - monthly cash flows for budget year (Jan – Dec)
  - monthly cash flows for two projected years (Jan – Dec)
  - Detail Budgets: O&M base, O&M clauses, Non-clause fuel, Below the Line, Revenue Enhancement, Capital base, Capital clauses, and Work force
  -

- **Five Year Capital Forecast** that includes:
  - first three years: monthly project cash flows
  - final two years: annual project amounts

- **Performance Measure Worksheet** that includes:
  - estimated performance for the current year
  - proposed indicators and performance targets for the budget year
  - projected indicators and performance for two projected years

All schedules must tie to the resource levels approved at the Final Budget Review Meeting on August 27th. Because the volume of data due on September 3rd is substantial, units are strongly encouraged to begin updating the schedules based on the resource levels approved at the August 1st meeting, then incorporating any changes resulting from the meeting on August 27th.

For additional guidance, see Section 2 – Supplemental Instructions for Completing Schedules and Deliverables.

* Note: finalized R-Schedules are due September 3rd. However, interim R-Schedules must be completed on the same dates that review meeting presentation materials are due to Corporate Budgets (see Calendar Items 3, 5, 7 and 9).

FP&L Strategic Imperatives and Critical Success Factors

FPL
Provide excellent customer service – Better understand exactly what our customers need/want – Further improve reliability and outage management, including outage duration, frequency and momentaries – Need to pay particular attention to "outliers", e.g. high number of outages, high number of momentaries, areas with large number of customer complaints – Prompt and efficient resolution of customer complaints
Improve our image with customers, regulators and politicians – Better leverage our accomplishments and image
Explore ways of mitigating fuel price volatility for our customers – Continue to pursue fuel diversity and reliability – Explore alternative hedging strategies
Develop and execute upon a flexible, comprehensive regulatory strategy which: – Responds to the changing paradigm in the state regarding CO2 mitigation, renewables, energy efficiency and conservation, hurricane resilience and new nuclear – Ensure investors are appropriately rewarded for investments addressing these changes – Minimizes customer bill impacts
Become much more effective in the regulatory/political arena
Effectively prepare for and achieve a successful outcome from the 2009 rate case
Pursue low carbon emitting generating technologies in the new generation plan – Execute on new gas plant plan – Explore feasibility of re-powering existing sites – Move quickly on renewables; work with suppliers to address Florida-specific needs (e.g., hurricane resilience) and drive down costs – Make significant progress on nuclear up-rates and new nuclear – Include expected future CO2 prices in all decision making

FP&L Strategic Imperatives and Critical Success Factors (continued)

Explore cost effective ways of expanding FPL's industry leading energy efficiency and conservation program – Design a regulatory structure for energy efficiency and conservation which creates the right incentives for all stakeholders – Create new and redesigned energy efficiency programs to increase customer penetration and reduce usage **Accelerate progress on Turkey Point nuclear improvements** **Step-up focus on new growth opportunities** – Expand FPLES; explore making energy efficiency a business opportunity – Grow wholesale generation business – Pursue gas infrastructure opportunities
Continued emphasis on improving O&M productivity and driving operational excellence
Explore ways to lower cost through greater deployment of capital and technology
Pursue widespread deployment of Smart Grid technology, including automated meters (AMI) A key enabler for both improving customer service and increasing energy efficiency

Florida Power & Light Company

2009 Planning Process

Guideline

****

Section 2

Supplemental Instructions for Completing Required Schedules and Deliverables

Overview of Supplemental Instructions and Appendix

Section 2 of the 2009 Planning Process Guidelines provides instructions for preparing the schedules and the deliverables identified on Section 1 – Page 10 of the guideline.

There are several new or modified planning and budgeting requirements this year. To assist you in identifying these changes, special symbols have been provided in the right hand margin throughout the Supplemental Instructions.

In addition to the on-line deliverables, there are three supplemental data schedules (blank forms) that must be prepared. These schedules are included in Section 3: Appendix of Supplemental Schedules and Deliverables (file: FPL_2009PlngProc_Sec3_Apndx.xls).

Each schedule in the appendix includes sample entries for illustrative purposes only. All of the schedules are formatted to print to legal size paper.

At the end of the appendix is a table linking pay period closing dates and pay days to the appropriate budget month. This information will be needed in order to properly cash flow the detail payroll budgets.

Performance Measures

General:

- The annual budgeting and planning process requires each business unit to develop and track business unit level performance measures throughout the year.
- All Business Unit Performance Measures are submitted in a format consistent with the exhibit in the Appendix. NEW
- New for this year, Corporate Budgets will issue a pre-formatted Performance Measure Worksheet to each business unit. The worksheet will feature print macros developed in response to senior management's request for different views of the worksheet at different stages of the review and approval process. Units will be able to add and delete performance measures per the instructions in the worksheet.
- All completed Business Unit Performance Measures Worksheets are to be filed in a specific directory (see <u>Accessing and Submitting Performance Measure Worksheets</u> below).

Completing the Performance Measure Worksheet:

- Your submittal should be in the prescribed format, using the pre-formatted Performance Measure Worksheet provided by Corporate Budgets (see exhibit in the Appendix).
  - Divide your measures into three groups:
    - ◊ operating measures
    - ◊ milestone measures, and
    - ◊ cross-functional measures.
- In your initial submittal:
  - Provide actual performance for 2003 through 2007
  - Provide a year-end estimate versus your current 2008 targets.
  - Identify your proposed measures and targets for 2009 through 2011.
- In your final submittal (early 2009):
  - Provide a year-end actual versus your current 2008 targets.
  - Identify your approved measures and targets for 2009 through 2011.

Accessing and Submitting Performance Measure Worksheets:

REMINDER

General

- Completed 2008 - 2009 Business Unit performance measure worksheets are to be filed in a specific directory accessible on the path **\\GOXSF01\GOFIN$\BUDGETS\perf0809\unit**, where **unit** is the abbreviation for your business unit (e.g. im for Information Management).
- The most recent copy of each unit's performance measure worksheet can be located on the path **\\GOXSF01\GOFIN$\BUDGETS\perf0708\unit**. However, this copy is for information only. For your submittal, use the pre-formatted Performance Measure Worksheet provided by Corporate Budgets.

Connecting to your directory

- To access your unit's directory, open **Windows Explorer**, click on **Tools,** then click on **Map Network Drive**. Map an available drive to **\\GOXSF01\GOFIN$\BUDGETS.** (Note: the Path is not case sensitive.).
- All of the folders in **\\GOXSF01\GOFIN$\BUDGETS** will be listed; however, you will only have access to your business unit's directory.
- Access to your unit's directory is based on an approved SLID ID.
- It is suggested that the number of individuals authorized to access this directory be kept to a minimum, as a means of controlling current versions of documents.
- To request access to your unit's directory, send the name of the individual, the SLID ID and the business unit name to the Corporate Budgets Manager (email - Dan Reilly/FNR/FPL).

R-Schedule & Supplemental Data Schedules

General Requirements:

- The annual budgeting and planning process requires each business unit to provide:
  - An updated R-Schedule which includes:
    - ◊ an estimate of expenditures and equivalent work force for year-end 2008,
    - ◊ funding and work force requirements for 2009, and
    - ◊ forecasted funding and work force requirements for 2010 and 2011.
  - Supplemental Data Schedules which include:
    - ◊ Charges to other business units
    - ◊ Charges to and from affiliates
- The R-Schedules are distributed and updated using the FPL SEM planning and forecasting tool.
- Supplemental Data Schedules will conform to the examples provided in the Appendix and will be placed in a specific directory.

Completing the R-Schedules:

NEW

General

- New for this year, interim R-Schedules are due on the same calendar dates that presentation materials are due to Corporate Budgets in advance of each of the scheduled review meetings (see Section 1 – Page 1, 2009 Planning Process Calendar, Items 3, 5 and 8).
- In early 2009, all 2008 year-end estimates will be updated with actual results for all financial and work force categories.

R-Schedule Data Entry Instructions

- Enter all required financial information in thousands of dollars.
- Provide a year-end 2008 estimate for the following:
  - All budgeted expense types and work force types
  - Any unbudgeted expense types and work force types, if appropriate.
  - Memo - Gross Payroll Dollars
- Provide funding requirements for all expense types and work force requirements for all employment types for 2009 through 2011 (see separate discussion of expense types and work force types in the following section).

- A blank R-Schedule facsimile is provided in the Appendix for your convenience. However, it may not be submitted. The on-line FPL SEM planning and forecasting tool must be used.

Expense Types

- For the following expense types, enter the net total cost to be charged to your budget by your unit AND any other unit(s). These costs should represent charges to FPL Utility only.
  - 1-Base O&M
  - 2-ECCR (Energy Conservation Cost Recovery Clause)
  - 4-O&M Fuel (Clause)
  - 5-O&M Capacity (Clause)
  - 6-Below the Line
  - 8-ECRC (Environmental Cost Recovery Clause)
  - 9-O&M NR Fuel (not recoverable through the Fuel Clause)
  - A-Capital Base
  - B-Capital ECCR (Energy Conservation Cost Recovery Clause)
  - F- Capital Non-Regulated
  - H-Capital ECRC (Environmental Cost Recovery Clause)
  - N-Other Expenses
  - V-Revenue Enhancement Capital
  - R-Revenue Enhancement Revenue
  - S-Revenue Enhancement Expense
- The following expense types/categories have special definitions
  - 7-Redirected Expenses
    - ◊ Include all resources under your unit's control that will be charged to other units, within FPL utility, via work order translations.
    - ◊ This category is sometimes referred to as the Clearing expense type.
    - ◊ Do not include what would be considered internal-clearing occurring within your own business unit.
  - G-Inter-company Expenses
    - ◊ Include all resources under your unit's control that will be charged to any of FPL Group's subsidiaries, other than FPL utility, via work order translations.
    - ◊ Do not include costs associated with Affiliate Fees.

- Memo: Gross Payroll Dollars
  - ◊ Include the gross FPL utility payroll for your business unit, regardless of where it will be charged (corresponds to payroll EACs 801 through 808 and 820 through 822).
  - ◊ Do not include payroll charged to you from other units or non-utility entities.

Equivalent Work Force Types

- For the following work force types, enter the number of FPL utility employees that will be 106'd to your business unit, on December 31, of each year. (Headcount as of last day of the year.)
  - FEX - FPL Exempt Employees
  - FEP - FPL Exempt Part-Time Employees (.5 each)
  - FNX - FPL Non- Exempt Employees
  - FPT - FPL Non-Exempt Part-Time Employees (.5 Each)
  - FBV - FPL Bargaining Unit Employees
- For the following work force types, enter the expected full time equivalent utilization, for each calendar year. (Average headcount over the course of the year.)
  - FTTE - FPL Full-Time Temporary Employees
  - FOT - FPL Overtime Equivalent Employees
  - TMP - Temporary Employees
  - CON - Contractor Employees
  - FTE formula = total hours to be worked in the year ÷ 2,080 man-hours in a year

Completing the Supplemental Data Schedules:

General

- There are three Supplemental Data Schedules.
  - Schedule 1: Charges to Other Business Units (Expense Type 7)
  - Schedule 2: Charges to Affiliates (Expense Type G and Unit Service Agreements)
  - Schedule 3: Charges from Affiliates

REMINDER

- Formats for each Supplemental Data Schedule are included in the Appendix
  - Enter the name of the unit and the name of the preparer in the spaces provide
  - Enter all data in thousands of dollars.
  - Shaded cells will calculate automatically.
  - Check for mathematical integrity when inserting, deleting or moving rows, etc.
  - Use the schedules as provided in the appendix or create your own stylized versions.

- Unit versions of supplemental schedules #1 through # 3 must include all information elements as shown in the examples in the appendix.
- It is not necessary to number each activity or item as illustrated in the sample data.
- Ensure all "dummy" data has been removed from any schedule being submitted.
- Submit completed schedules as individual worksheets or together in a work book.
- If submitting completed schedules as a work book, delete any schedules not used.
- Identify the unit and schedule(s) when naming a file or work book.

- Completed Supplemental Data Schedules are to be placed in a specific directory
  - The directory is accessible on the path **GOXSF01\GOFIN$\BUDGETS\perf0809\unit**, where **unit** is the abbreviation for your business unit (e.g. im for Information Management).
  - For instructions on how to access the directory, refer to Section 2 – Page 3 Connecting to your directory.

Schedule 1: Charges to Other Business Units

- Identify 2009 expenditures incurred by your business unit, but reflected in another business unit's budget (your unit's expense type 7)
- Totals should tie to the R-Schedule

Schedule 2: Charges to Affiliates

- Expense Type G – Inter-Company Expenses
  - Identify the amount to be direct-charged to each subsidiary through the FPL financial system, and provide a description of the nature of the charges.
  - Note: FPL-E typically accepts only payroll charges through FPL's financial system. However, certain recurring transactions, such as insurance premiums, customarily charged to FPL-E via Expense Type G should be budgeted on Schedule 3a.
  - Totals should tie to the R-Schedule
- Service Agreement Fees
  - This category applies only to Energy, Markets & Trading; Information Management, the Power Generation Division; and the Nuclear Division.
  - Include the value of services provided to affiliates, recovered dollar for dollar via the fee arrangement. Do not include the credit offsets from the affiliate, or the overheads recovered in Accounting Location 10.
  - No corresponding R-Schedule data
- Prepare a separate schedule for each year: 2009, 2010 and 2011.

Schedule 3: Charges from Affiliates

- Identify the fully loaded charges to be incurred from each affiliate, by expense type
- Prepare a separate schedule for each year: 2009, 2010 and 2011.
- No corresponding R-Schedule data

Five Year Capital Forecast

General Requirements:

- The annual budgeting and planning process requires each business unit to provide:
  - An updated Five Year Capital Forecast which includes:
    - ◊ an estimate of capital expenditures for year-end 2008,
    - ◊ funding requirements for 2009 through 2013
- The Five Year Capital Forecast is distributed and updated using the FPL SEM planning and forecasting tool.
- Special requirements
  - Demolition and Removal Costs for a major project
    - ◊ must be budgeted in a separate sub-activity
    - ◊ the words Demolition or Removal must appear in the sub-activity name and description
  - Land Held for Future Use
    - ◊ must be budgeted in a separate budget activity or sub-activity, and
    - ◊ the words Future Use must appear in the activity name and description
  - Units must submit a list of major project retirements
    - ◊ Individual items of property with historical costs of $10 million or more
    - ◊ Identify the month and year (2008 through 2013) of retirement

REMINDER

Completing the Five Year Capital Forecast

General

- The format of this year's Five Year Capital Forecast is the same as last year
- The threshold for identifying a Major project remains at $10 million.

Overview

- The primary function of the Five Year Capital Forecast is to provide a projection of capital expenditures for the Finance Department's financial forecasting model.
- All capital expenditures are to be forecasted using a budget activity (also known as a budget item).
  - Capital budget activity (BA) numbers are in the five digit format 0 0 # # # .
  - Under certain circumstances it may be necessary, or desirable, to break a BA into sub-activities.
    - ◊ The capital sub-activity (SA) format is six characters, combining alphas and numerics at the discretion of the business unit.
    - ◊ If no SA is specified, six zeros are assigned as the default SA.
- BAs and SAs are "defined" by certain characteristics.
  - All amounts budgeted under a particular BA or SA must represent expenditures that are consistent with the definition of that BA or SA.
  - The characteristics of a BA or SA include the following:
    - ◊ FERC function code
    - ◊ in-service date
    - ◊ expense type
    - ◊ AFUDC eligibility
    - ◊ depreciable/non-depreciable status
    - ◊ plant site (generation business units only), and
    - ◊ Major / minor designation.
- BAs and SAs are designated as either Major or minor.
  - A specific project is considered a Major project when the total cost over the life of the project is $10 million or more.
    - ◊ A Major project requires a specific BA number unique to the project.
    - ◊ For example, the West Count Energy Center 1 & 2 project is **BA 00766**.
    - ◊ Stratify a Major project (Major BA) into sub-activities (Major SAs) for the following conditions:
      - ➢ when a Major BA comprises individual sub-projects that have individual total life time costs of $10 million or more
      - ➢ when the sub-projects have different in-service dates, regardless of their respective sub-project cost
      - ➢ to identify demolition or removal costs
      - ➢ to identify land held for future use
      - ➢ when the business unit finds a further breakdown to be a meaningful way to forecast the project.

- A specific project is considered a minor project when the total cost over the life of the project is less than $10 million.
    - ◊ A minor project may be budgeted under a specific BA, or
    - ◊ A minor project may be grouped with similar capital expenditures under a so called blanket minor BA, such as
        - ➢ BA 00691 (Office Furniture, Fixtures and Equipment), or
        - ➢ BA 00001 (Miscellaneous Forecast Projects).
    - ◊ The availability of blanket minor BA 00001 permits many business units to forecast much of their capital requirements under a single BA/SA, assuming there are no Major BAs to be considered.
        - ➢ To forecast minor projects that have the same FERC function, use blanket minor BA 00001, in conjunction with the appropriate SA, per the table below.
        - ➢ Exception: The two generation business units need an individual blanket minor for each plant site (see BA Definitions and Plant Site table in the Reference section at the end of this document.)

BA	SA	FERC Function	FERC Function Description
00001	000001	1	Steam Generation
00001	000002	2	Nuclear Generation
00001	000003	3	Other Generation
00001	000004	4	Transmission
00001	000005	5	Distribution-Line
00001	000006	6	Distribution-Substation
00001	000007	7	Buildings
00001	000008	8	General Plant Equipment
00001	000009	9	Transportation Equipment
00001	000010	0	Intangible Plant

- When budgeting any capital expenditures, it is important to ensure that the definition of the BA or SA accurately describes all of the capital expenditures budgeted or forecasted under that BA or SA. If not, then the expenditures should be allocated to two or more BAs or SAs as necessary. (See also the Data Confirmation section below).

- **Note:** The Five Year Capital Forecast folders and the Detail Budget Planning folders are independent, that is, updating one does not update the other. Consequently, it will be necessary for the business units to ensure that the annual totals and monthly cash flows in both systems reconcile with each other.

The two cash flows will be considered reconciled if the difference for any given month is less than $1,000. Annual totals should be within $10,000 of each other.

Five Year Capital Forecast folder Data Entry Instructions

- Enter all required information in whole dollars.
- For each BA/SA
  - Provide a year-end estimate for 2008. Enter an annual amount in December.
  - Provide monthly cash flows for your 2009 budget.
  - Provide monthly cash flows for your 2010 and 2011 forecasts.
  - Provide a forecast for 2012 and 2013. Enter an annual amount in December.

Data Confirmation

- In order for the Finance Department's financial model to make intelligent use of the forecasted BA/SA cash flows, it must have access to non-quantitative information such as the associated FERC function, in service date, depreciation status, etc.
- All of the non-quantitative information used in the forecast will be obtained directly from the definitions in the BA/SA tables.
- Since the accuracy of the forecast depends on the non-quantitative information being correct, it will be necessary for all units to **perform the following steps prior to the due date** for completing the workbooks **(see 2009 Planning Process Calendar Item 10):**
  - access the BA/SA Table using the Lotus Notes facility
  - find all of the forecasted BAs and SAs listed in your Five Year Capital Forecast folder
  - confirm the data associated with each of those BAs and SAs is correct
  - if any data in the BA/SA Table is not correct, modify the BA/SA
- The Data Confirmation procedure is not necessary if you are using blanket BA 00001 or blanket SAs 0000001 through 000010, as they are already correct. Do not attempt to change these BA/SA combinations.
- The BA/SA definition section below may assist you in completing the Data Confirmation step.
  - Function:
    - ◊ The FERC Function. A single digit code describing a classification of expenditures under the FERC System of Accounts. See "Use of the Minor Blanket BA 00001" above for a table of the codes.
  - Depreciation:
    - ◊ "D" if depreciable, "N" if non-depreciable. "A" if amortizable. Land is the only expenditure that is non-depreciable. Land should be in a separate BA or SA with a code of "N."

- Expense Type:
  - ◊ An alpha code to further describe the type of expenditure within the capital budget type (A = Base, B = ECCR, F = Non regulated (below-the-line or FPL Group) H = ECRC, V = Revenue Enhancement)
- Major/Minor:
  - ◊ Capital "M" if Major, blank if minor. A Major BA represents a specific project with a total life of the project cost of $10 million or greater. See the "Overview" section above for further information.
- Plant Site:
  - ◊ A three digit code. Applies primarily to Plant Engineering & Construction, Power Generation and Nuclear. Expenditures pertaining to a specific plant site must be budgeted in a BA or SA unique to that site, per the table below. For all other expenditures use default plant site 000.
- AFUDC:
  - ◊ Indicates eligibility for an accounting treatment known as Allowance for Funds Used During Construction. Used for Major BAs and SAs only. Check with your Accounting Business Unit Representative to make the determination. "Y" if yes. "N" if no.
- In Service Date:
  - ◊ The date the project will be completed and go into service. Used for Major BAs and SAs only. Not applicable for miscellaneous projects under BA 00001.

Code	Plant Site	Code	Plant Site	Code	Plant Site
010	Cutler	131	Cape Canaveral Modernization	180	Martin #1, #2, #3 & #4
040	Riviera #1 & #2	140	Turkey Point Old	182	Martin #8
041	Riviera Modernization	141	Turkey Point #5	185	Martin Gas Pipeline
050	Putnam	146	Turkey Point #6	186	Martin #7
070	Sanford #3	147	Turkey Point #7	190	West County Energy Center #1 & #2
072	Sanford Repowered #4 & #5	148	Turkey Point Common #6 & #7	191	West County Energy Center #3
080	Fort Lauderdale	150	St. Lucie Common	500	SJRPP #1 & #2
110	Fort Myers Old #1 & #2	151	St. Lucie #1	501	SJRPP Coal Car
112	Fort Myers Repowered #1 & #2	152	St. Lucie #2	502	SJRPP Switchyard
113	Fort Myers Peaking Units	160	St. Lucie Wind	503	SJRPP Coal Terminal
120	Port Everglades	170	Manatee #1 and #2	505	Scherer #4
130	Cape Canaveral	171	Manatee #3		

Detail Cash Flow Budgeting

General

NEW

- The 2009 planning cycle requires each business unit to provide
  - expenditure detail budgets
    - ◊ remaining monthly cash flows for 2008 (August – December)
    - ◊ monthly cash flows for 2009 through 2011 (January – December)
  - a monthly work force detail budget for 2009, 2010 and 2011
- Detail budgets will be loaded using the FPL SEM planning and forecasting tool.

Expenditure Detail Budgets

- Complete expenditure detail budgets will be prepared for the remaining months of 2008 and each month of 2009 through 2011.
- Provide the following level of detail:
  - Budget Responsibility Code (BRC)
  - Budget activity / Sub-activity (BASA)
  - Expenditure Analysis Code (EAC)
  - Expense Type
- Monthly cash flows are required for all years.
- Enter all information in whole dollars.
- Totals for each expense type should tie to the R-Schedule.

Work Force Detail Budget

- A work force detail budget must be prepared for 2009, 2010 and 2011 for each work force type that appears on the R-Schedule.
- At a minimum, units must prepare the work force detail budget at the business unit level. Units may choose to prepare the detail work force budget at lower levels, if so desired.
- For the following work force types, enter the number of FPL utility employees that will be employed by your business unit, on the last day of each month. (Headcount as of last day of each month.)
  - FEX - FPL Exempt Employees
  - FEP - FPL Exempt Part-Time Employees (count as 0.5 each)
  - FNX - FPL Non- Exempt Employees

- FPT - FPL Non-Exempt Part-Time Employees (count as 0.5 Each)
- FBV - FPL Bargaining Unit Employees
- The December month-end value for each manpower type for each year should tie to the R-Schedule.

- For the following work force types, enter the expected full time equivalent utilization, for each calendar month. (Average headcount over the course of each month.)
    - FTTE - FPL Full-Time Temporary Employees
    - FOT - FPL Overtime Equivalent Employees
    - TMP - Temporary Employees
    - CON - Contractor Employees
    - FTE formula = (total hours to be worked in the month) ÷ (the number of workdays in the month x 8 hours)
    - The 12-month average for each manpower type should tie to the R-Schedule.

Additional Guidance for Budgeting 2009 - 2011 Detail

Payroll

- A unit's **gross payroll** must be budgeted under the appropriate expense type and in the appropriate 800 level EACs. Use expense type 7-Redirected Expenses for payroll to be charged to other units, or "cleared" to capital through a work order allocation (e.g., through an engineering order, or EO). (See also **Transfer Out / Transfer In** below.)
- To differentiate the payroll associated with hours worked from **other forms of compensation**, use the following payroll EACs as appropriate:
    - 809 – Long Term Incentives and Deferred Compensation
    - 820 – Performance Excellence Rewards Program (PERP)
    - 821 – Payroll - Other Earnings
    - 822 – Payroll - Lump Sum

REMINDER

- Budget for **pay increases,** per the 2009 Planning Process Economic Assumptions, which are issued separately (see Section 1 – Page 1, 2009 Planning Process Calendar, Item 1).
- There will be 26 budgeted **pay periods** in 2009. Three pay periods will occur during the months of March and August. All other months will have two pay periods. For more information on pay periods and paychecks, refer to the Section 3 Appendix.

Expense Types

- A detail budget must be prepared for each expense type that appears on the R-Schedule for 2009, 2010 & 2011.
- The following **expense types** should be budgeted as appropriate.
- **Expenses**
    - 1-Base O&M
    - 2-ECCR (Energy Conservation Cost Recovery Clause)
    - 4-O&M Fuel (Clause)
    - 5-O&M Capacity (Clause)
    - 6-Below the Line
    - 7-Redirected Expenses (see Transfer Out / Transfer In below)
    - 8-ECRC (Environmental Cost Recovery Clause)

- 9-O&M NR Fuel (not recoverable through the Fuel Clause)
- G-Inter-company Expenses (see Transfer Out / Transfer In below)
- N-Other Expenses
- S-Revenue Enhancement Expense

- **Capital Expenditures**
  - A-Capital Base
  - B-Capital ECCR (Energy Conservation Cost Recovery Clause)
  - F-Capital Non-regulated
  - H-Capital ECRC (Environmental Cost Recovery Clause)
  - V-Revenue Enhancement Capital
- **Revenues**
  - R-Revenue Enhancement Revenue (budgeted as a credit)
- **Equivalent Work Force Types**
  - FEX - FPL Exempt Employees
  - FEP - FPL Exempt Part-Time Employees (.5 each)
  - FNX - FPL Non- Exempt Employees
  - FPT - FPL Non-Exempt Part-Time Employees (.5 Each)
  - FBV - FPL Bargaining Unit Employee
  - FTTE - FPL Full-Time Temporary Employees
  - FOT - FPL Overtime Equivalent Employees
  - TMP - Temporary Employees
  - CON - Contractor Employees

- **Special Notes Regarding Expense Types:**
  - Use of **expense type N** is limited to Stores and Automotive expenses and certain Corporate Real Estate expenses.
  - The assignment of **revenue enhancement expense types S and V** is determined solely by the accounting treatment the actual transaction receives when recorded in the general ledger. Use of expense types S and V is limited to existing revenue enhancement programs in the following business units: Engineering and Construction (Integrated Supply Chain), Marketing and Communications, and Retail. Business unit proposals for **new revenue enhancement programs** should be submitted to the appropriate Business Unit Accounting Advisor and Corporate Budgets prior to the commitment of any corporate resources, the implementation of the program, or the inclusion of required resources in the 2009 budgeting and planning deliverables.

- A unit planning **direct charges to non-utility** entities should budget 100% of its cash expenditures in **expense type G** (see Transfer Out / Transfer In below). The Accounting Department will budget for the recovery of associated corporate overheads.
- Staff unit expenditures that are **allocable to non-utility** entities through the **Affiliate Management Fee** should be budgeted 100% in **Base O&M**. The Accounting Department will budget for the further allocation of these costs at the corporate level.
- Units with **unit specific service agreement fee** arrangements should budget both the Base O&M expense and the required offset **in a unique BASA, dedicated to the fee**. The Accounting Department will budget for the recovery of associated corporate overheads.

Transfer Out / Transfer In

- There are three types of transfers employed to plan and track operating expenses that are under the control of one organizational entity, but are budgeted in a different organizational entity.
  - Business Unit to Business Unit
  - Budget Responsibility Code to Budget Responsibility Code (within a business unit)
  - Company to Company
- **Business Unit to Business Unit:** The unit providing the services should make debit entries only in **expense type 7**, using normal payroll and non-payroll EACs. After all detail budgets have been entered and approved, Information Management's Financial Systems group will offset the debit entries by generating credits in expense type 7, using 400 level EACs.
- The unit that will receive the actual costs should budget the appropriate expense type (Base O&M, ECCR, etc), using 300 level EACs for payroll and regular EACs for all non-payroll. It is a **corporate requirement** that all between-unit transfers be budgeted by both the sending and receiving units. (See example A.)
- **Budget Responsibility Code to Budget Responsibility Code:** Within-unit transfers are budgeted in the same manner as unit-to-unit transfers described above, using expense type 7. However, planning and tracking of within-unit transfers is **optional**. A unit may elect to eliminate internal transfers, limit transfers to certain roll-up levels and above, or allow transfers to occur at the BRC level. To ensure the *actual* within-unit transfers will be recorded consistent with the *plan*, contact Information Management's Financial Systems group, and ask them to turn off the transfer mechanism, or reset it to a certain roll-up level. The default setting will create within-unit transfers at the BRC level, which is the lowest possible level. (See example A.)
- **Company to Company:** Direct charges to FPL Group, or any of its subsidiaries, are accomplished by charging an ER 99 work order, or a work order that translates to a subsidiary account. Such charges will be budgeted in a manner similar to the unit-to-unit transfers described above, except that the

providing unit will use **expense type G**, instead of expense type 7, and no credit budget will be generated. It is a **corporate requirement** that the unit providing such services budget for all between company transfers. (See example B.)

Benefits

- Business units should not budget for **capitalized Pension & Welfare or Taxes & Insurance**. Accounting and Human Resources budget for all benefits for the entire company.

EACs

- From time to time EACs are added or deleted.
- A complete list of valid EACs is available on the Financial Business Unit web site.

Budget Responsibility Code (BRC)

- The Budget Responsibility Code (BRC) is intended to represent an individual (or a position if the position is vacant) with accountability for specific budgeted resources. As a general rule, a BRC should be assigned wherever there is a meaningful level of managerial or supervisory control. Business unit heads, vice presidents, directors, managers and supervisors are likely candidates for individual BRCs.
- The planning and forecasting tool generates budget folders for all active BRCs. When several BRCs are regarded as a group, they can be aggregated under a higher level roll-up BRC for reporting purposes. The roll-up BRC will reflect the roll-up budget of its subordinate BRCs. However, because the roll-up BRC will not have any resources of its own no budget folder will be generated in FPL SEM.
- Under most circumstances, an individual contributor who has no direct reports should not be assigned a separate BRC, unless he or she is accountable for significant non-payroll financial resources. A BRC that represents an activity, an expense type, or another category of cost not assignable to a specific individual should be eliminated and the costs budgeted under the appropriate BRC(s).

Budget Activity (BA) and Sub-Activity (SA)

- A Budget Activity (BA) describes a broad category of work performed within the Budget Responsibility Code (BRC). Each BRC is required to have at least one BA. Work that is common to an entire business unit should be described by a single BA, which can be shared by all of the BRCs in the unit. If it is necessary to subdivide the work (BA) further, sub-activities (SA) should be established.

- A BA number is assigned by the budget system and is five numeric characters in length. All BAs have a default sub-BA of 000000. An SA is always six positions in length and may be alpha, numeric, or a combination of both. The business unit may create additional SAs as required.
- A BA should be "in service" indefinitely, or at least until a major change in the nature of the work of the unit (or the BRC) occurs. Do not establish new BAs each year for basic work that continues from year to year. SAs may need to be dropped or added annually, as specific segments of work are completed or started. Otherwise, SAs should be reused each year as much as possible, in the same manner as BAs.
- Avoid establishing BAs or SAs when other budgeting or tracking elements already exist for that purpose. For example, avoid setting up a BA or SA to capture a single EAC. At a minimum, each BA will correspond to at least one work order, often several. If there are a large number of work orders in use, and it is desirable to have a plan for each one, do not establish a separate BA for each work order. Instead use SAs to achieve a one-to-one correspondence with the work orders.
- There is no minimum dollar threshold for the establishment of a BA, nor is there a limit on the maximum number of BAs that a BRC may use. However, to maximize the efficiency of the "engine" (Essbase) that drives the FMIP reporting system, it may be necessary for the Budget Department and/or Information Management's Accounting Systems group to work with a unit that has a disproportionate number of BAs and SAs to the relative size of its budgeted resources. (**Note:** special additional rules apply to the establishment of capital BAs, also known as budget items. These rules are explained in the 2009 Five-Year Capital Forecast Guideline).

Example A

Transfer-out and Transfer-in

Payroll: Between-units and Within-unit

Example: Unit A plans to spend $600 on exempt payroll (EAC 803), of which, $100 will be charged to unit B.

The originating unit will budget for its own needs in expense type 1. Transfer-out costs will be budgeted under expense type 7 (re-directed O&M), which will net to zero. For the transfer-out payroll, a debit will be budgeted by the unit under EAC 803 in expense type 7. After all detail budgets are loaded, Accounting Systems will generate an offsetting credit in expense type 7 under EAC 403. The receiving unit will budget for the transfer-in payroll under EAC 303 in expense type 1.

This treatment makes it easier for the originating unit to identify its own exempt payroll (expense type 1), its payroll incurred on behalf of others (expense type 7, excluding 400 level EACs), and its gross payroll (sum of 1 and 7, excluding 400 level EACs). Each of the 800 series payroll EACs has a corresponding 400 and 300 series EAC to be used consistent with the example below. (See next page for non-payroll.)

		Base O&M	Redirected O&M	
	EAC	1	7	Total
Unit A (Originating)	803	500	100	600
	403	-	(100)	(100)
	Total	500	-	500
Unit B (Receiving)	303	100	-	100
	Total	100	-	100
Total Company (Net)	803	500	100	600
	403	-	(100)	(100)
	303	100	-	100
	Total	600	-	600

Example A (continued)

Transfer-out and Transfer-in

Non-Payroll: Between-units and Within-unit

Example: Unit A plans to spend $600 on contractor costs (EAC 662), of which, $75 will be charged to unit B. Unit A will also incur $200 of miscellaneous expenses (EAC 625), of which, $25 will be charged to unit B. In total, unit A will incur $800 of costs, $100 of which will be charged to unit B.

The originating unit will budget for its own needs in expense type 1. Transfer-out costs will be budgeted under expense type 7 (re-directed O&M), which will net to zero. For the transfer-out costs, the unit will budget debits in expense type 7, using the regular EACs. After all detail budgets are loaded, Accounting Systems will generate a single offsetting credit equal to all of the non-payroll EACs in expense type 7. The credit will be entered in EAC 412. The receiving unit will budget for the transfer-in costs under expense type 1, using regular EACs.

Note: The receiving unit should not budget EAC 411 for the transfer-in of non-payroll expenses. EAC 411 is no longer in use for planning purposes, but it will remain active for historical reporting.

		Base O&M	Redirected O&M	
	EAC	1	7	Total
Unit A (Originating)	662	525	75	600
	625	175	25	200
	412	-	(100)	(100)
	Total	700	-	700
Unit B (Receiving)	662	75	-	75
	625	25	-	25
	Total	100	-	100
Total Company (Net)	662	600	75	675
	625	200	25	225
	412	-	(100)	(100)
	Total	800	-	800

Example B

Transfer-out and Transfer-in

Payroll: Between companies only (direct charges to non-utility entities)

Example: Unit A plans to spend $600 on exempt payroll (EAC 803), of which, $100 will be charged to a non-utility entity.

The originating unit will budget for its own needs in expense type 1. Transfer-out costs will be budgeted under expense type G (Inter-company O&M). For the transfer-out payroll, a debit will be budgeted by the unit under EAC 803 in expense type G. The budgets of the non-utility entities are separate from the FPL utility budget, so there is no need for Accounting Systems to generate an offsetting credit in expense type G.

This treatment makes it easier for the originating unit to identify its own exempt payroll (expense type 1), its payroll incurred on behalf of others (expense type G), and its gross payroll (sum of 1 and G). (See next page for non-payroll.)

	Base O&M	Inter-Company O&M	
EAC	**1**	**G**	**Total**
803	500	100	600
Total	500	100	600

Example B (continued)

Transfer-out and Transfer-in

Non-Payroll: Between companies only (direct charges to non-utility entities)

Example: Unit A plans to spend $600 on contractor costs (EAC 662), of which, $75 will be charged to a non-utility entity. Unit A will also incur $200 of miscellaneous expenses (EAC 625), of which, $25 will be charged to non-utility. In total, unit A will incur $800 of costs, $100 of which will be charged to non-utility.

The originating unit will budget for its own needs in expense type 1. Transfer-out costs will be budgeted under expense type G (Inter-company O&M). For the transfer-out costs, the unit will budget debits in expense type G, using the regular EACs. The budgets of the non-utility entities are separate from the FPL utility budget, so there is no need for Accounting Systems to generate an offsetting credit in expense type G.

	Base O&M	Inter-Company O&M	
EAC	1	G	Total
662	525	75	600
625	175	25	200
Total	700	100	800

Florida Power & Light Company

2009 Planning Process

Guideline

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Section 3

Appendix
of
Supplemental
Schedules and Deliverables

2008 - 2009 FPL CORPORATE INCENTIVE PLAN PERFORMANCE MEASURES

BUSINESS UNIT NAME HERE

WGT '08	WGT '09	PERFORMANCE MEASURES	Actual 2003	Actual 2004	Actual 2005	Actual 2006	Actual 2007	2008 YEAR END ESTIMATE	2008 YEAR END TARGET	ON TARGET YEAR END? [1]	COMMENTS [2]	TARGET 2009	FORECAST 2010	FORECAST 2011	ORG LEVEL [3]	2008 STRETCH TARGET [4]
75%	75%	**OPERATING MEASURES**														
		Base O&M ($MM)	$8.8	$9.0	$9.5	$10.0	$10.5	$9.6	$10.0	Better		$9.3	$9.1	$8.9	Corp	Yes
		Capital ($MM)	$15.0	$12.0	$11.0	$10.0	$10.0	$10.0	$9.0	Worse	unplanned expenditures	$9.8	$8.2	$8.2	Corp	
		Total Full Time Equivalent Employees (FPL & All Others)	95	97	97	99	100	100	100	Target		100	100	101	Corp	
25%	25%															
		Number of incidents	8	9	10	10	11	8	10	Better		8	8	8	Unit	
		Frequency of occurrences	7	5	5	6	4	5	4	Worse	ineffective measures	3	3	3	Unit	Yes
		MILESTONE MEASURES														
		Completion of work on project "A" by year end						11/06	12/06	Better					Unit	
		Completion of project "B" by end of 3Q 2007										8/05			Unit	
		CROSS-FUNCTIONAL MEASURES														
		None														

NOTE 1: indicate either Better, Worse or Target
NOTE 2: comments required if Estimate is Worse than Target
NOTE 3: indicate level of organization this indicator is recommended for 2008: Corp or Unit.
NOTE 4: indicate "Yes" if this a stretch target for 2008.

SAMPLE ONLY
DO NOT SUBMIT - USE PRE-FORMATTED SHEET PROVIDED BY CORPORATE BUDGETS

R-Schedule - Summary
Business Unit:
Financial Data in Thousands of Dollars

SAMPLE ONLY
DO NOT SUBMIT - USE FPL SEM

Expense Types	Current Approved 2008	Estimated Actual 2008	Variance Over/(Under) 2008	Variance Percent	Funds Request 2009	Difference Inc / (Dec) 2008 Est Act	Variance Percent	Funds Request 2010	Difference Inc / (Dec) 2009	Variance Percent	Funds Request 2011	Difference Inc / (Dec) 2010	Variance Percent
1 - O&M Base	140,000	135,000	(5,000)	-3.6%	140,000	5,000	3.7%	145,000	5,000	3.6%	145,000	-	0.0%
2 - O&M ECCR	10,000	9,000	(1,000)	-10.0%	10,000	1,000	11.1%	11,000	1,000	10.0%	8,000	(3,000)	-27.3%
4 - O&M Fuel	-	-	-	N/A	-	-	N/A	-	-	N/A	-	-	N/A
5 - O&M Capacity	-	-	-	N/A	-	-	N/A	-	-	N/A	-	-	N/A
8 - O&M ECRC	5,000	4,500	(500)	-10.0%	5,500	1,000	22.2%	6,000	500	9.1%	5,000	(1,000)	-16.7%
9 - O&M NR Fuel	-	-	-	N/A	-	-	N/A	-	-	N/A	-	-	N/A
Total Utility O&M	**155,000**	**148,500**	**(6,500)**	**-4.2%**	**155,500**	**7,000**	4.7%	**162,000**	**6,500**	**4.2%**	**158,000**	**(4,000)**	**-2.5%**
6 - Below the Line Expenses	1,000	900	(100)	-10.0%	1,100	200	22.2%	1,200	100	9.1%	1,500	300	25.0%
7 - Redirected Expenses (to other business units)	-	-	-	N/A	-	-	N/A	-	-	N/A	-	-	N/A
G - Inter-company Expenses (to non-utility)													
S - Revenue Enhancement Expenses	-	-	-	N/A	-	-	N/A	-	-	N/A	-	-	N/A
N - Other Expenses	-	-	-	N/A	-	-	N/A	-	-	N/A	-	-	N/A
Total Other Expenses	**1,000**	**900**	**(100)**	**-10.0%**	**1,100**	**200**	22.2%	**1,200**	**100**	**9.1%**	**1,500**	**300**	**25.0%**
A - Capital Base	100,000	100,000	-	0.0%	110,000	10,000	10.0%	120,000	10,000	9.1%	130,000	10,000	8.3%
B - Capital ECCR	-	-	-	N/A	-	-	N/A	-	-	N/A	-	-	N/A
F - Capital Non-Regulated	-	-	-	N/A	-	-	N/A	-	-	N/A	-	-	N/A
H - Capital ECRC	-	-	-	N/A	-	-	N/A	-	-	N/A	1,000	1,000	N/A
V - Revenue Enhancement Capital	-	-	-	N/A	-	-	N/A	-	-	N/A	-	-	N/A
Total Capital	**100,000**	**100,000**	**-**	**0.0%**	**110,000**	**10,000**	10.0%	**120,000**	**10,000**	**9.1%**	**131,000**	**11,000**	**9.2%**
R - Revenue Enhancement Revenue	-	-	-	N/A	-	-	N/A	-	-	N/A	-	-	N/A
Memo: Gross Payroll Dollars	20,000	19,500	(500)	-2.5%	20,500	1,000	5.1%	21,000	500	2.4%	22,000	1,000	4.8%
Workforce													
FEX - FPL Exempt Employees	150	150	-	0.0%	155	5	3.3%	160	5	3.2%	160	-	0.0%
FEP - FPL Exempt Part-Time Employees (.5 each)	-	-	-	N/A	-	-	N/A	-	-	N/A	-	-	N/A
FNX - FPL Non-Exempt Employees	100	100	-	0.0%	105	5	5.0%	110	5	4.8%	105	(5)	-4.5%
FPT - FPL Non-Exempt Part-Time Employees (.5 each)	-	-	-	N/A	-	-	N/A	-	-	N/A	-	-	N/A
FBV - FPL Bargaining Unit Employees	-	-	-	N/A	-	-	N/A	-	-	N/A	-	-	N/A
FPL Total (Full-Time & Part-Time)	**250**	**250**	**-**	**0.0%**	**260**	**10**	4.0%	**270**	**10**	**3.8%**	**265**	**(5)**	**-1.9%**
FTTE - Full-Time Temporary Employees	-	-	-	N/A	-	-	N/A	-	-	N/A	-	-	N/A
FOT - FPL Overtime Equivalent Employees	-	-	-	N/A	-	-	N/A	-	-	N/A	-	-	N/A
TMP - Temporary Employees	-	-	-	N/A	-	-	N/A	-	-	N/A	-	-	N/A
CON - Contractor Employees	-	-	-	N/A	-	-	N/A	-	-	N/A	-	-	N/A
Total Variable Workforce	**-**	**-**	**-**	**N/A**	**-**	**-**	N/A	**-**	**-**	**N/A**	**-**	**-**	**N/A**
Total Full Time Equivalents	**250**	**250**	**-**	**0.0%**	**260**	**10**	4.0%	**270**	**10**	**3.8%**	**265**	**(5)**	**-1.9%**

Schedule 2 - Charges to Other Business Units
2009 Funds Request
Business Unit: **Prepared By:**
Financial Data in Thousands

Unit to Incur Costs	Expense Type 7 Redirected Expenses	Process / Activity
Corporate Communications		
Distribution	5,000	Programming support for ...
Energy Marketing and Trading		
Financial		
General Counsel		
Governmental Affairs - Federal		
Governmental Affairs - State		
Human Resources		
Information Management		
Internal Audit		
Nuclear Division		
Plant Engineering & Construction		
Power Generation Division		
Regulatory Affairs		
Resource Assessment & Planning		
Retail		
Transmission		
Location - 10		
Total (must agree to summary R-Schedule total)	5,000	

Schedule 2 - Charges to Affiliates
2009 Funds Request
Business Unit: **Prepared By:**
Financial Data in Thousands

Description of Product / Service Provided	Group Capital Payroll	Group Capital Non Payroll	Group Capital Total	FPL Energy [2] Payroll	FPL Energy [2] Non Payroll	FPL Energy [2] Total	Fibernet Payroll	Fibernet Non Payroll	Fibernet Total	FPLES Payroll	FPLES Non Payroll	FPLES Total	Palms Payroll	Palms Non Payroll	Palms Total	Total Payroll	Total Non Payroll	Total Total
Affiliate Receiving Charges																		
Expense Type G - Direct Charge [1]																		
Item 1: Banking Services	-	300	300		[redacted]	-	-	-	-	-	-	-	-	-	-	-	300	300
Item 2: Executive Support	1,500	-	1,500	-	[redacted]	-	-	-	-	-	-	-	-	-	-	1,500	-	1,500
Item 3: Legal Services	-	-	-	500	[redacted]	500	-	-	-	-	-	-	-	-	-	500	-	500
Item 4	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 5	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 6	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 7	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 8	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 9	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 10	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 11	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 12	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 13	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 14	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 15	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Expense Type G - Direct Charges	1,500	300	1,800	500	[redacted]	600	-	-	-	-	-	-	-	-	-	2,000	300	2,300
Service Agreement Fee [3]	-	-	-	100	20	120	-	-	-	-	-	-	-	-	-	100	-	100
Total Non-Utility Support Provided	1,500	300	1,800	600	20	620	-	-	-	-	-	-	-	-	-	2,100	300	2,400

[1] Excludes Overheads & Loadings (All units as appropriate)
[2] Includes Seabrook, Duane Arnold, and Point Beach
[3] Excludes Overheads, Loadings & Credit Offset (Nuclear, Pwr Gen, EMT, IM only)

Schedule 2 - Charges to Affiliates
2010 Funds Request
Business Unit: **Prepared By:**
Financial Data in Thousands

Description of Product / Service Provided	Group Capital Payroll	Group Capital Non Payroll	Group Capital Total	FPL Energy [2] Payroll	FPL Energy [2] Non Payroll	FPL Energy [2] Total	Fibernet Payroll	Fibernet Non Payroll	Fibernet Total	FPLES Payroll	FPLES Non Payroll	FPLES Total	Palms Payroll	Palms Non Payroll	Palms Total	Total Payroll	Total Non Payroll	Total Total
	Affiliate Receiving Charges																	
Expense Type G - Direct Charge [1]																		
Item 1: Banking Services	-	300	300		[redacted]	-	-	-	-	-	-	-	-	-	-	-	300	300
Item 2: Executive Support	1,500	-	1,500	-	[redacted]	-	-	-	-	-	-	-	-	-	-	1,500	-	1,500
Item 3: Legal Services	-	-	-	500	[redacted]	500	-	-	-	-	-	-	-	-	-	500	-	500
Item 4	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 5	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 6	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 7	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 8	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 9	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 10	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 11	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 12	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 13	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 14	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 15	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Expense Type G - Direct Charges	**1,500**	**300**	**1,800**	**500**	[redacted]	**500**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**2,000**	**300**	**2,300**
Service Agreement Fee [3]	-	-	-	100	20	120	-	-	-	-	-	-	-	-	-	100	-	100
Total Non-Utility Support Provided	**1,500**	**300**	**1,800**	**600**	**20**	**620**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**2,100**	**300**	**2,400**

[1] Excludes Overheads & Loadings (All units as appropriate)
[2] Includes Seabrook, Duane Arnold, and Point Beach
[3] Excludes Overheads, Loadings & Credit Offset (Nuclear, Pwr Gen, EMT, IM only)

Schedule 2 - Charges to Affiliates
2011 Funds Request
Business Unit: **Prepared By:**
Financial Data in Thousands

Description of Product / Service Provided	Affiliate Receiving Charges																	
	Group Capital			FPL Energy [2]			Fibernet			FPLES			Palms			Total		
	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total
Expense Type G - Direct Charge [1]																		
Item 1: Banking Services	-	300	300		[redacted]	-	-	-	-	-	-	-	-	-	-	-	300	300
Item 2: Executive Support	1,500	-	1,500	-	[redacted]	-	-	-	-	-	-	-	-	-	-	1,500	-	1,500
Item 3: Legal Services	-	-	-	500	[redacted]	500	-	-	-	-	-	-	-	-	-	500	-	500
Item 4	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 5	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 6	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 7	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 8	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 9	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 10	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 11	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 12	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 13	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 14	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Item 15	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Expense Type G - Direct Charges	**1,500**	**300**	**1,800**	**500**	[redacted]	**500**	-	-	-	-	-	-	-	-	-	**2,000**	**300**	**2,300**
Service Agreement Fee [3]	-	-	-	100	20	120	-	-	-	-	-	-	-	-	-	100	-	100
Total Non-Utility Support Provided	**1,500**	**300**	**1,800**	**600**	**20**	**620**	-	-	-	-	-	-	-	-	-	**2,100**	**300**	**2,400**

[1] Excludes Overheads & Loadings (All units as appropriate)
[2] Includes Seabrook, Duane Arnold, and Point Beach
[3] Excludes Overheads, Loadings & Credit Offset (Nuclear, Pwr Gen, EMT, IM only)

Schedule 3 - Charges from Affiliates
2009 Funds Request
Business Unit: **Prepared By:**
Financial Data in Thousands

		Affiliate Providing Products / Services [1]																	
		Group Capital			FPL Energy			Fibernet			FPLES			Palms			Total		
Description of Product / Service Provided	Expense Type	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total
Item 1: Construction management	Base Capital	-	-	-	1,500	200	1,700	-	-	-	-	-	-	-	-	-	1,500	200	1,700
Item 2: Legal services	Base O&M	-	-	-	750	100	850	-	-	-	-	-	-	-	-	-	750	100	850
Item 3		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 4		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 5		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 6		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 7		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 8		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 9		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 10		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 11		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 12		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 13		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 14		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 15		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Total Charges from Affiliates		-	-	-	2,250	300	2,550	-	-	-	-	-	-	-	-	-	2,250	300	2,550

[1] Includes fully loaded costs

Schedule 3 - Charges from Affiliates
2010 Funds Request
Business Unit: Prepared By:
Financial Data in Thousands

Description of Product / Service Provided	Expense Type	Affiliate Providing Products / Services [1]																	
		Group Capital			FPL Energy			Fibernet			FPLES			Palms			Total		
		Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total
Item 1: Construction management	Base Capital	-	-	-	1,500	200	1,700	-	-	-	-	-	-	-	-	-	1,500	200	1,700
Item 2: Legal services	Base O&M	-	-	-	750	100	850	-	-	-	-	-	-	-	-	-	750	100	850
Item 3		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 4		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 5		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 6		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 7		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 8		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 9		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 10		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 11		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 12		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 13		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 14		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 15		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Total Charges from Affiliates		-	-	-	2,250	300	2,550	-	-	-	-	-	-	-	-	-	2,250	300	2,550

[1] Includes fully loaded costs

Schedule 3 - Charges from Affiliates
2011 Funds Request
Business Unit: **Prepared By:**
Financial Data in Thousands

Description of Product / Service Provided	Expense Type	Affiliate Providing Products / Services [1]																	
		Group Capital			FPL Energy			Fibernet			FPLES			Palms			Total		
		Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total	Payroll	Non Payroll	Total
Item 1: Construction management	Base Capital	-	-	-	1,500	200	1,700		-	-	-	-	-	-	-	-	1,500	200	1,700
Item 2: Legal services	Base O&M	-	-	-	750	100	850	-	-	-	-	-	-	-	-	-	750	100	850
Item 3		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 4		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 5		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 6		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 7		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 8		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 9		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 10		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 11		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 12		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 13		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 14		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Item 15		-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Total Charges from Affiliates		-	-	-	2,250	300	2,550	-	-	-	-	-	-	-	-	-	2,250	300	2,550

[1] Includes fully loaded costs

FLORIDA POWER & LIGHT COMPANY
AND SUBSIDIARIES
DOCKET NO. 080677-EI
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Planning Process Guidelines
Exhibit REB-2, Page 49 of 50

Table Linking Pay Periods, Payroll Closings and Pay Days to the Budget Month

	Budget Mnth / Yr	Pay Period #	Payroll Closing (Friday)	Pay Day (Thursday)	Budget Mnth / Yr	Pay Period #	Payroll Closing (Friday)	Pay Day (Thursday)	Comments (2000 - 2006 available in hidden rows of electronic file version)
2008	Jan-08	1	4-Jan	10-Jan	Jul-08	14	3-Jul	10-Jul	
	Jan-08	2	18-Jan	24-Jan	Jul-08	15	18-Jul	24-Jul	
	Feb-08	3	1-Feb	7-Feb	Aug-08	16	1-Aug	7-Aug	
	Feb-08	4	15-Feb	21-Feb	Aug-08	17	15-Aug	21-Aug	
	Mar-08	5	29-Feb	6-Mar	Sep-08	18	29-Aug	4-Sep	
	Mar-08	6	14-Mar	20-Mar	Sep-08	19	12-Sep	18-Sep	
	Mar-08	7	28-Mar	3-Apr	Sep-08	20	26-Sep	2-Oct	
	Apr-08	8	11-Apr	17-Apr	Oct-08	21	10-Oct	16-Oct	
	Apr-08	9	25-Apr	1-May	Oct-08	22	24-Oct	30-Oct	
	May-08	10	9-May	15-May	Nov-08	23	7-Nov	13-Nov	
	May-08	11	23-May	29-May	Nov-08	24	21-Nov	26-Nov	
	Jun-08	12	6-Jun	12-Jun	Dec-08	25	5-Dec	11-Dec	**26 pay checks issued.**
	Jun-08	13	20-Jun	26-Jun	Dec-08	26	19-Dec	23-Dec	**26 budgeted pay periods.**
2009	Jan-09	1	2-Jan	8-Jan	Jul-09	14	3-Jul	9-Jul	
	Jan-09	2	16-Jan	22-Jan	Jul-09	15	17-Jul	23-Jul	
	Feb-09	3	30-Jan	5-Feb	Aug-09	16	31-Jul	6-Aug	
	Feb-09	4	13-Feb	19-Feb	Aug-09	17	14-Aug	20-Aug	
	Mar-09	5	27-Feb	5-Mar	Aug-09	18	28-Aug	3-Sep	
	Mar-09	6	13-Mar	19-Mar	Sep-09	19	11-Sep	17-Sep	
	Mar-09	7	27-Mar	2-Apr	Sep-09	20	25-Sep	1-Oct	
	Apr-09	8	10-Apr	16-Apr	Oct-09	21	9-Oct	15-Oct	
	Apr-09	9	24-Apr	30-Apr	Oct-09	22	23-Oct	29-Oct	
	May-09	10	8-May	14-May	Nov-09	23	6-Nov	12-Nov	
	May-09	11	22-May	28-May	Nov-09	24	20-Nov	25-Nov	
	Jun-09	12	5-Jun	11-Jun	Dec-09	25	4-Dec	10-Dec	**26 pay checks issued.**
	Jun-09	13	19-Jun	25-Jun	Dec-09	26	18-Dec	23-Dec	**26 budgeted pay periods.**
2010	Jan-10	1	31-Dec	7-Jan	Jul-10	14	2-Jul	8-Jul	
	Jan-10	2	15-Jan	21-Jan	Jul-10	15	16-Jul	22-Jul	
	Feb-10	3	29-Jan	4-Feb	Aug-10	16	30-Jul	5-Aug	
	Feb-10	4	12-Feb	18-Feb	Aug-10	17	13-Aug	19-Aug	
	Mar-10	5	26-Feb	4-Mar	Aug-10	18	27-Aug	2-Sep	
	Mar-10	6	12-Mar	18-Mar	Sep-10	19	10-Sep	16-Sep	
	Mar-10	7	26-Mar	1-Apr	Sep-10	20	24-Sep	2-Oct	
	Apr-10	8	9-Apr	15-Apr	Oct-10	21	8-Oct	14-Oct	
	Apr-10	9	23-Apr	29-Apr	Oct-10	22	22-Oct	28-Oct	
	May-10	10	7-May	13-May	Nov-10	23	5-Nov	11-Nov	
	May-10	11	21-May	27-May	Nov-10	24	19-Nov	24-Nov	
	Jun-10	12	4-Jun	10-Jun	Dec-10	25	3-Dec	9-Dec	**26 pay checks issued.**
	Jun-10	13	18-Jun	24-Jun	Dec-10	26	17-Dec	23-Dec	**26 budgeted pay periods.**
2011	Jan-11	1	31-Dec	6-Jan	Jul-11	14	1-Jul	7-Jul	
	Jan-11	2	14-Jan	20-Jan	Jul-11	15	15-Jul	21-Jul	
	Jan-11	3	28-Jan	3-Feb	Aug-11	16	29-Jul	4-Aug	
	Feb-11	4	11-Feb	17-Feb	Aug-11	17	12-Aug	18-Aug	
	Feb-11	5	25-Feb	3-Mar	Aug-11	18	26-Aug	1-Sep	
	Mar-11	6	11-Mar	17-Mar	Sep-11	19	9-Sep	15-Sep	
	Mar-11	7	25-Mar	31-Mar	Sep-11	20	23-Sep	29-Sep	
	Apr-11	8	8-Apr	14-Apr	Oct-11	21	7-Oct	13-Oct	
	Apr-11	9	22-Apr	28-Apr	Oct-11	22	21-Oct	27-Oct	
	May-11	10	6-May	12-May	Nov-11	23	4-Nov	10-Nov	
	May-11	11	20-May	26-May	Nov-11	24	18-Nov	24-Nov	
	Jun-11	12	3-Jun	9-Jun	Dec-11	25	2-Dec	8-Dec	**26 pay checks issued.**
	Jun-11	13	17-Jun	23-Jun	Dec-11	26	16-Dec	22-Dec	**26 budgeted pay periods.**

= relevant range of data for budget year = three pay period month for budgeting purposes

NOTES: Payroll is budgeted based on payroll closing dates, not pay days. For budgeting and accounting purposes, payroll periods that close after the 28th of the month are budgeted and recorded in the following month's business. In the special case of February, if the payroll period closes after the 25th, it is budgeted and recorded in March, except during leap years, in which case, if the payroll period closes after the 26th, it is budgeted and recorded in March.

Normally, the application of these rules results in 26 pay periods being budgeted each year. Occasionally, the application of the rules results in the need to budget for a 27th pay period, as was the case in 2001. It will not again be necessary to budget for a 27th pay period until the year 2012.

Per IRS rules, the first pay check issued each year is assigned pay period number one. From time to time, the first budgeted pay period of the year represents the second pay check issued for the year. Budget year 2003 was an example of this situation. Budget analysts should take note of this when analyzing payroll budget details by pay period number. In 2004, pay period number one resynchronized with the first budgeted pay period for the year.

Pay events that normally would fall on an observed holiday have been shown as occurring on the last work day prior to the holiday.

Normally, the issuance of pay checks every 14 days results in 26 pay checks being issued each year. Occasionally, 27 pay checks are issued in a single year. For example, the first pay day of 2004 fell on the New Years holiday, so it was prepaid on December 31, 2003 causing a 27th pay check that year. Note: the additional pay day did not require the business units to budget an additional pay period in 2003.

FLORIDA PUBLIC SERVICE COMMISSION

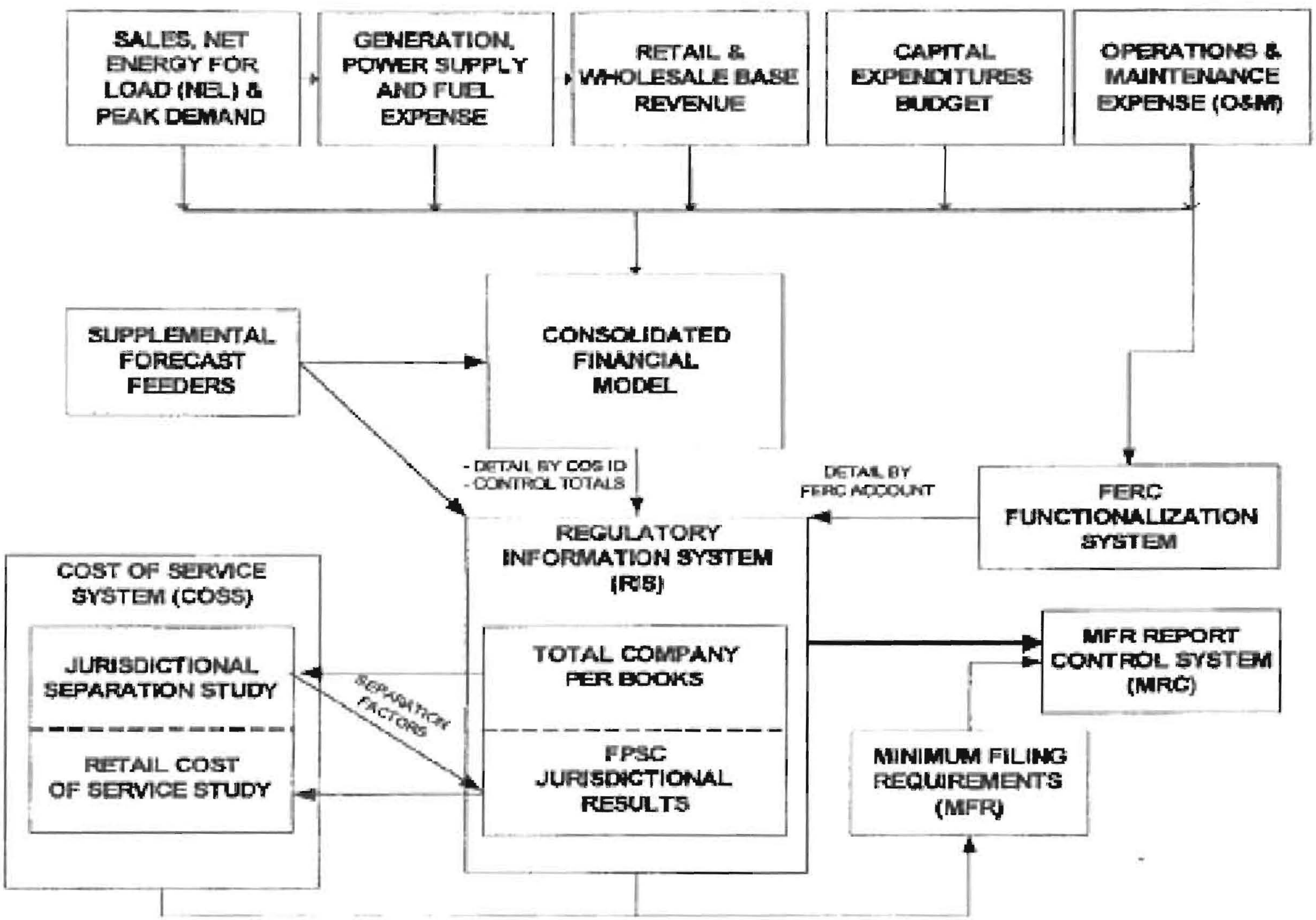
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 55

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS Robert E. Barrett, Jr. (REB-3)

DATE 08/28/09

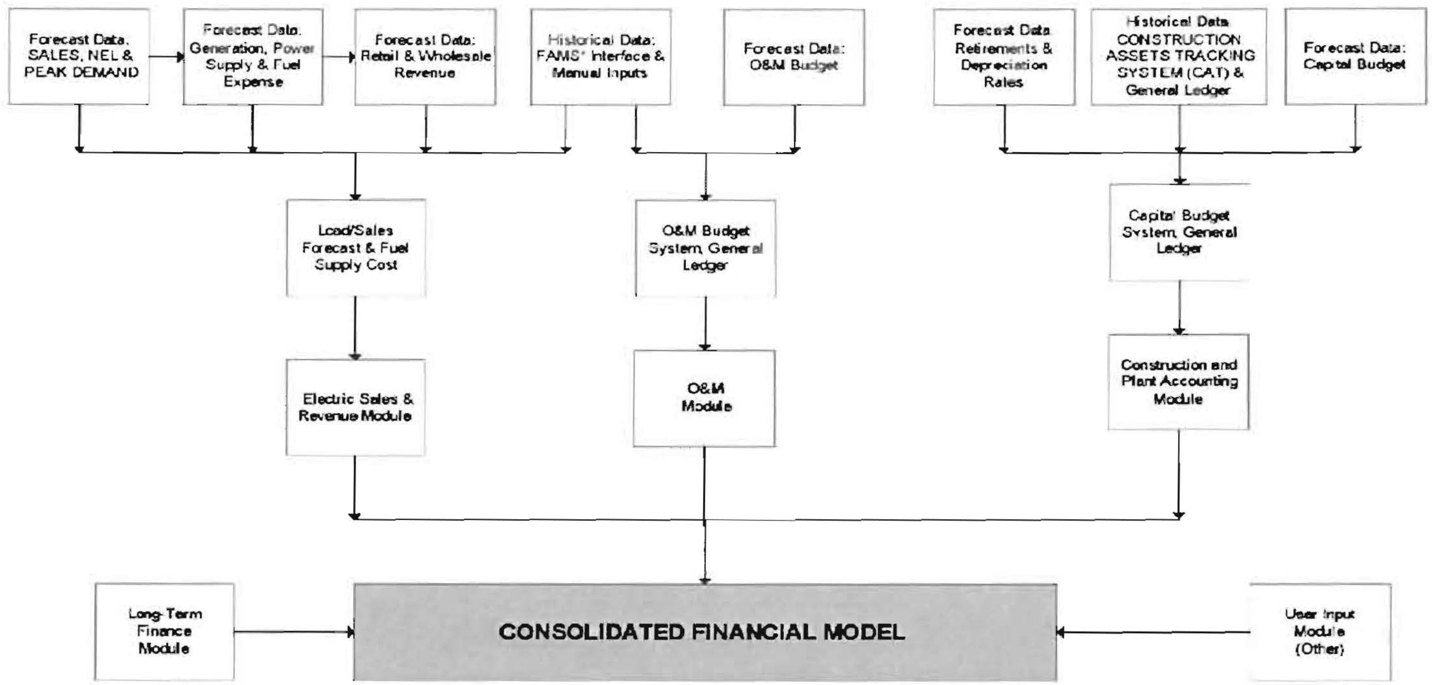
FLORIDA POWER & LIGHT COMPANY
FORECASTING PROCESS OVERVIEW



DOCKET NO. 080677-EI
MFR F-5 Forecasting Flowchart and Models
Exhibit REB-3, Page 1 of 2

FLORIDA POWER & LIGHT COMPANY
AND SUBSIDIARIES
DOCKET NO. 080677-EI
MFR NO. F-05
ATTACHMENT 01 OF 00
PAGE 1 OF 1

FLORIDA POWER & LIGHT COMPANY
CONSOLIDATED FINANCIAL MODEL (CFM)



*FAMS: FINANCIAL ACCOUNTING MANAGEMENT SYSTEM

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080677-EI & 090130-EI **EXHIBIT** 56

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS Robert E. Barrett, Jr. (REB-4)

DATE 08/28/09

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 080677-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/10
____ Prior Year Ended ___/___/___
____ Historical Test Year Ended ___/___/__

Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl

(1) (2) (3) (4) (5) (6) (7) (8) (9)

I. SALES, CUSTOMERS, NET ENERGY FOR LOAD

GENERAL ASSUMPTIONS

	2010
A. Population (Florida)	18,979,698
B. Florida Non-Agricultural Employment (000's)	7,867
C. Florida Real Household Disposable Income (Base 2000) (000's of Dollars)	71
D. FPL Service Territory Cooling Degree Hours (Base 72 Degree Temperature)	1,947
E. FPL Service Territory Heating Degree Hours (Base 66 Degree Temperature)	355
F. FPL Service Territory Average Temperature Summer Peak Day (Fahrenheit	85
G. FPL Service Territory Average Temperature Winter Peak Day (Fahrenheit	46

H. 2010 Sales by Revenue Class - Most likely (in Million KWH)

Residential	Commercial	Industrial	Street & Highway	Other Authority	Railway	Total Retail	**Sales For Resale**	**Total** [1]
51,427	45,417	3,606	451	36	91	101,029	2,137	103,165

I. 2010 Customers by Revenue Class

Residential	Commercial	Industrial	Street & Highway	Other Authority	Railway	Total Retail	**Sales For Resale**	**Total** [1]
4,010,837	521,804	12,686	3,214	194	23	4,548,759	4	4,548,763

J. 2010 Net Change in Customers by Revenue Class

Residential	Commercial	Industrial	Street & Highway	Other Authority	Railway	Total Retail	**Sales For Resale**	**Total** [2]
16,665	11,923	159	35	-4	0	28,777	0	28,777

[1] Totals may not add-up due to rounding.
[2] Average customers - sum of the projected customers for each month divided by twelve.

Supporting Schedules: Recap Schedules: E-10, C-40

DOCKET NO. 080677-EI
MFR F-8 MAJOR FORECAST ASSUMPTIONS
EXHIBIT REB-4, PAGE 1 OF 28

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 080677-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

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Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl

	(1)	(2)
I.	K. **Most Likely Forecast of Monthly Net Energy for Load (Million KWH**	
		2010
	January	7,981
	February	7,265
	March	8,094
	April	8,506
	May	9,382
	June	10,401
	July	10,834
	August	11,041
	September	10,702
	October	9,547
	November	8,384
	December	8,070
		110,207
	L. **Most Likely Forecast of System Monthly Peaks (Megawatts**	
		2010
	January	18,790
	February	15,533
	March	16,265
	April	17,462
	May	19,429
	June	20,192
	July	20,873
	August	21,147
	September	20,696
	October	19,287
	November	16,835
	December	15,791

II. INFLATION RATE FORECAST

	Most Likely Annual Rates of Change 2010	
A.	2.0%	**Consumer Price Index (CPI)** The CPI Measures the price change of a constant market basket of goods and services over time For company purposes it is a useful escalator for determining trends in wage contracts and income payments, excluding construction work.

Supporting Schedules:

Recap Schedules: E-10, C-40

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FLORIDA PUBLIC SERVICE COMMISSION

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		(1)	(2)
II.	B.	2.2%	**GDP Deflator** The GDP deflator is the broadest of all categories and captures price trends for the four major macro-economic sectors in the nation, which are: the household sector, the business sector, the government sector and the foreign sector. The GDP deflator tends to be more stable than the other indices and is used where very broad price trends are needed.
	C.	1.3%	**Producer Price Index** **(PPI): All Commodities** The PPI for all commodities is a comprehensive measure of the average changes in price received in primary markets by producers of commodities in all stages of processing. This index represents price movements in the manufacturing, agriculture, forestry, fishing, mining, gas and electricity, and public utilities sector of the economy
	D.	1.3%	**Producer Price Index** **(PPI) Intermediate Materials** PPI for Intermediate Materials reflects changes in the prices of commodities that have been processed but require further processing before being sold to the final user
	E.	1.0%	**Producer Price Index** **(PPI) Finished Producer Goods** PPI for Finished Producer Goods reflects changes in the prices of two major components: finished consumer goods and capital equipment received by producers
	F.	2.8%	**Producer Price Index** **Public Utility Private Fixed Investment (except telecom** PPI for Public Utility Private Fixed Investment (except telecom) reflects changes in the prices for fixed investment including investment in power plants, distribution lines, substations, transmission lines, and local natural gas pipelines
	G.	3.5%	**Compensation Per Hour (Non-Farm Business Sector)** **Index: All workers, including pension and benefits** The compensation per hour index reflects the changes in total wage and benefit compensation for non farm business labor

Supporting Schedules: Recap Schedules: E-10, C-40

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FLORIDA PUBLIC SERVICE COMMISSION COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES DOCKET NO.: 080677-EI	EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.	Type of Data Shown: _X_ Projected Test Year Ended 12/31/10 ____ Prior Year Ended ___/___/___ ____ Historical Test Year Ended ___/___/___ Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl

Line No. (1) (2) (3)

III. FINANCING AND INTEREST RATE ASSUMPTIONS

General Assumptions

A. Target Capitalization Ratios

During the projected test year, Florida Power & Light Company's capitalization is projected to be as follows: equity approximately 55%, and debt approximately 45%, adjusted for off-balance sheet obligations

B. Preferred Stock Premium and Underwriting Discount

It is assumed that no preferred stock will be issued.

C. First Mortgage Bond Prices and Underwriting Discount

It is assumed that first mortgage bonds will be issued to the public at par with an underwriting commission of .875%.

Interest Rate Assumptions

	2010
D. Long Term Debt	6.9%
Short Term Debt	Although the company maintains several lines of credit, the company forecasts them at zero
E. Pollution Control Bonds	1.6%
F. Preferred Stock	No preferred stock outstanding.
G. 30-Day Commercial Paper	2.2%

Supporting Schedules: | Recap Schedules: E-10, C-40

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IV. IN SERVICE DATES OF MAJOR PROJECTS

A.

BUDGET ITEM # (1)	PROJECT DESCRIPTION (2)	IN SERVICE DATE * (3)	
	Nuclear Generation Projects		
406	Turkey Point Excellence Program	2009-2012	(Multiple Projects with Various In-Service Dates)
193	St. Lucie Unit 1 & 2 Butt Weld Project	U1-05/2010 & U2-12/2010	
346	Turkey Point Spent Fuel Project	06/2010	
392	St. Lucie Unit 1 Extended Power Uprate Project**	06/2010 & 12/2011	
137	St. Lucie Unit 2 Incore Instrument Replacement	12/2010	
194	St. Lucie Unit 2 Pressurizer Replacement	12/2010	
393	Turkey Point Unit 3 Extended Power Uprate Project**	12/2010 & 5/2012	
398	St. Lucie Unit 2 Extended Power Uprate Project**	01/2011 & 06/2012	
399	Turkey Point Unit 4 Extended Power Uprate Project**	05/2011 & 12/2012	
556	St. Lucie & Turkey Point Life Cycle Management Project	U1-11/2011 & U2-12/2010	
410	St. Lucie Corrosion & Coatings Project	12/2011	
528	Turkey Point Integrated Bottom Mount Instrument Project	05/2012	
410	St. Lucie Procedure Upgrade Project	12/2012	
	Fossil Generation Projects		
380	Manatee Unit 1 800 MW Cycling Project**	04/2010	
086	Scherer Unit 4 Baghouse Addition Project**	04/2010	
152	West County Energy Center Unit 3 Project	06/2011	
177	Scherer Unit 4 Select Catalytic Reduction CAIR Project**	04/2012	
177	Scherer Unit 4 Flue Gas Desulfer FGD CAIR Project**	04/2012	
506	Cape Canaveral Modernization	06/2013	
505	Riviera Modernization	06/2014	
	Other Generation Projects		
424	Space Coast Solar Project**	07/2010	
423	Martin Solar Project**	12/2010	
151	St. Lucie Wind Project	05/2011	
	Transmission Projects		
277	Princeton Injection Project	05/2011	
287	Princeton Injection North Area Project	12/2011	
291	Bunnell-St.Johns 230kv Line	12/2011	
294	Norris Volusia Line	12/2011	
325	Bobwhite Manatee 230kv Line	12/2011	
349	Hobe-Sandpiper #2 Transmission Line	12/2011	
524	Martin South Bay Conversion West Area Project	11/2011	
524	Martin South Bay Conversion Central Area Project	12/2013	
313	Green Project	06/2015	
	Intangible & General Plant Projects		
014	Nuclear Asset Management System Project	07/2010	
718	FENA Phase 1 Project	12/2010	
164	SAP Project	09/2011	
587	SCC EMS Project	12/2013	

** Projects which have a foreseeable monetary impact in fiscal year 2010*

** Projects which are recovered, or partially recovered, through other mechanisms

Supporting Schedules: | Recap Schedules: E-10, C-40

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Line No. (1) (2) (3) (4) (5)

V. MAJOR GENERATING UNIT OUTAGE ASSUMPTIONS

A. Nuclear Maintenance Schedules (including outage period and reason)

Unit	2010 Outage Period	2010 Outage Description
St. Lucie Unit 1	4/5/2010 - 6/10/2010	Refueling, Extended Power Uprate Project
St. Lucie Unit 2	11/15/2010 - 1/18/2011	Refueling, Extended Power Uprate Project, Alloy 600 Cold Leg RCP nozzles
Turkey Point Unit 3	9/26/2010 - 12/5/2010	Refueling, Extended Power Uprate Project

B. Fossil Units Outage Schedule (including outage period and reason)

Unit	2010 Outage Start	2010 Outage End	2010 Outage Description
FT. MYERS 2	10/23/10	11/5/10	A HGP, MINOR HRSG, GEN INSP
FT. MYERS 2	2/6/10	2/12/10	A HRSG INSPECTION
FT. MYERS 2	10/9/10	10/22/10	B HGP, MINOR HRSG, GEN INSP
FT. MYERS 2	2/13/10	2/19/10	B HRSG INSPECTION
FT. MYERS 2	2/20/10	2/26/10	C HRSG INSPECTION
FT. MYERS 2	2/27/10	3/5/10	D HRSG INSPECTION
FT. MYERS 2	3/6/10	3/12/10	E HRSG INSPECTION
FT. MYERS 2	10/9/10	10/22/10	F HGP, MINOR HRSG, GEN INSP
FT. MYERS 2	3/13/10	3/19/10	F HRSG INSPECTION
FT. MYERS 2	10/9/10	10/29/10	GEN INSP / P-91 PIPING REPLACEMENT
FT. MYERS 3	5/1/10	5/7/10	A COMBUSTOR INSPECTION
FT. MYERS 3	4/10/10	4/16/10	B COMBUSTOR INSPECTION
LAUDERDALE 4	4/3/10	4/11/10	A COMBUSTOR INSPECTION
LAUDERDALE 4	4/3/10	4/30/10	B MAJOR CT, MINOR HRSG, GEN INSP
LAUDERDALE 4	4/3/10	4/27/10	TURBINE VALVES, GEN INSP
LAUDERDALE 5	10/2/10	10/10/10	A COMBUSTOR INSPECTION
LAUDERDALE 5	10/2/10	10/29/10	B MAJOR CT, MINOR HRSG, GEN INSP
LAUDERDALE 5	10/2/10	10/26/10	COMMON BALANCE OF PLANT REPAIRS
MANATEE 1	1/30/10	4/9/10	MAJOR STM TURBINE, GEN, & BOILER
MARTIN 8	9/1/10	9/7/10	A HRSG INSPECTION

Supporting Schedules: Recap Schedules: E-10, C-40

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Line No.	(1)	(2)	(3)	(4)	(5)
1	V. B.				
2	MARTIN 8	9/1/10	9/7/10		D HRSG INSPECTION
3	MARTIN 1	10/23/10	11/12/10		MINOR BOILER, TURBINE VALVES
4	MARTIN 3	1/16/10	2/5/10		B MAJOR CT & HRSG, GEN INSP
5	PT EVERGLADES 4	10/16/10	12/14/10		MAJOR BOILER, TURBINE VALVES, GEN INSP
6	PUTNAM	9/1/10	9/5/10		COOLNG TOWER FAN
7	PUTNAM 1	2/1/10	2/5/10		1GT1 COMBUSTOR INSPECTION
8	PUTNAM 1	10/16/10	12/10/10		MAJOR STM TURBINE & GEN
9	PUTNAM 2	9/1/10	9/5/10		2GT1 COMBUSTOR INSPECTION
10	SANFORD 4	3/13/10	3/19/10		A HRSG INSPECTION
11	SANFORD 4	3/13/10	3/19/10		B HRSG INSPECTION
12	SANFORD 4	3/13/10	3/19/10		C HRSG INSPECTION
13	SANFORD 4	3/13/10	3/19/10		D HRSG INSPECTION
14	SANFORD 4	3/13/10	4/2/10		TURBINE VALVES & GEN INSP / P-91 PIPING REPLACEMENT
15	SANFORD 5	2/27/10	3/14/10		A COMBUSTOR INSPECTION/ S0-S5 REPLACE
16	SANFORD 5	3/6/10	3/23/10		B HGP, MINOR HRSG, GEN INSP / S0-S5 REPLACE / 24K
17	SANFORD 5	6/5/10	6/20/10		D COMBUSTOR INSPECTION / S0-S5 REPLACE
18	SCHERER 4	1/9/10	4/3/10		BOILER / HG CONTROLS UPGRADE (BAGHOUSE TIE IN)
19	ST. JOHNS RIVER POWER PARK 2	2/27/10	3/29/10		BLR,FGD,BFPT
20	TURKEY POINT 5	2/27/10	3/12/10		A HOT GAS PATH, MINOR HRSG
21	TURKEY POINT 5	2/27/10	3/12/10		B HOT GAS PATH, MINOR HRSG
22	TURKEY POINT 5	3/13/10	3/26/10		C HOT GAS PATH, MINOR HRSG
23	TURKEY POINT 5	3/13/10	3/26/10		D HOT GAS PATH, MINOR HRSG
24	TURKEY POINT 5	3/6/10	3/19/10		GENERATOR INSP
25	TURKEY POINT 2	4/3/10	6/1/10		MAJOR BOILER, STM TURBINE, & GEN/SWITCHGEAR
26	WEST COUNTY ENERGY CENTER 1	3/6/10	3/15/10		1 ST WARRANTY OUTAGE
27	WEST COUNTY ENERGY CENTER 1	3/6/10	3/15/10		1A WARRANTY OUTAGE & CI
28	WEST COUNTY ENERGY CENTER 1	3/6/10	3/15/10		1B WARRANTY OUTAGE & CI
29	WEST COUNTY ENERGY CENTER 1	3/16/10	3/25/10		1C WARRANTY OUTAGE & CI
30	WEST COUNTY ENERGY CENTER 2	9/18/10	9/27/10		2 ST WARRANTY OUTAGE
31	WEST COUNTY ENERGY CENTER 2	9/18/10	9/27/10		2A WARRANTY OUTAGE
32	WEST COUNTY ENERGY CENTER 2	9/18/10	9/27/10		2B WARRANTY OUTAGE
33	WEST COUNTY ENERGY CENTER 2	9/18/10	9/27/10		2C WARRANTY OUTAGE

Supporting Schedules: Recap Schedules: E-10, C-40

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Line No.		(1)	(2)
1	**VI. INTERCHANGE AND PURCHASED POWER ASSUMPTIONS**		
2			
3	**A. Contractual Commitments for Scheduled Interchange/Purchased Power**		
4			
5	**1 Unit Power Purchase (UPS) - Southern Companies**		
6	a. Capacity (MW) based on 2004 Net Dependable Capacity Unit Ratings:		
7		2009	932
8		2010	932
9	b. Minimum (MW) scheduling requirements		
10		2009	379
11		2010	82
12	c. Capacity and energy costs based on Southern's estimate, subject to true up and audit.		
13			
14	d. Energy costs recovered through Fuel Cost Recovery Clause (FCRC) and capacity costs recovered		
15	through Capacity Cost Recovery Clause (CCRC).		
16			
17	**2 Unit Power Purchase - St Johns River Power Park**		
18	a. 30% of rated net capacity of each unit is considered purchased power.		
19	b. All energy scheduled by FPL in excess of 20% (FPL owned generation) is considered		
20	purchased energy.		
21	c. Capacity costs are recovered through CCRC and base rates. Energy costs are recovered		
22	through FCRC.		

Supporting Schedules: Recap Schedules: E-10, C-40

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3 Power Sold and Economy Energy Purchases (Schedule "OS")

a. Schedule OS sales based upon projected market prices and expected available generation relative to FPL's projected incremental cost of sale (generation and transmission)

b. Schedule OS purchases based upon FPL's projected incremental generation cost relative to projected market prices plus incremental costs and transmission.

c. Energy & transmission costs of OS purchases recovered through the FCRC. For OS sales, FCRC credited for incremental generation cost, CCRC credited for FPL transmission incurred to make sale, Base credited for incremental costs of running gas turbines, if applicable, and FCRC credited for gain on sale

4 Interchange related to St Lucie Unit 2 Reliability Exchange agreement

a. Based on P-MArea projection for PSL 1 and PSL 2 output as applied to the contract formula.

5 Schedule of New and Expiring Interchange/Purchase Power Contracts for the period.

a. Broward South Contract entered into in 1987 expires August 1, 2009 .

b. Palm Beach (SWA) Contract expires March 31, 2010.

c. Broward North Contract entered into in 1987 expires on December 21, 2010.

6 Purchased Power from Qualifying Facilities:

		Capacity (MW)	Energy (MWH)
a. Firm			
	2009	740	5,454,647
	2010	690	4,966,032
b. As Available			
	2009	n/a	448,604
	2010	n/a	448,604

Supporting Schedules:

Recap Schedules: E-10, C-40

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Line No. (1) (2) (3)

VI. 7 Schedule of Sales and Purchased Power Contracts for the Period (contracts Impact 2010)

a. Sales: Key West 45 MW RTC Capacity and Energy (1/1/10 to 12/31/10)
Reedy Creek 8 MW Call option on Capacity and Incremental Energy (1/1/10 to 12/31/10)
Lee County EMC Partial Requirements up to 300 MW (1/1/10 to 12/31/10)
Homestead 2 MW Call Option on Capacity and Incremental Energy (1/1/10 to 12/31/10)
Florida Keys Coop Partial Requirements ~119 MW (1/1/2010 to 12/31/2010)

b. Purchases: Oleander Power Project, LP dated April 30, 2001 (6/1/2002 through 5/31/2012)

VII. FUEL ASSUMPTIONS

A. Fuel Related Assumptions

1 Fossil Fuel

The current real and nominal fuel price forecast for light and heavy fuel oil, natural gas, coal, and petroleum coke, and the projection for the availability of natural gas to the FPL system for 2009, 2010 and 2011 were issued on November 6, 2008 and were based on current and projected market conditions, and existing supply and transportation contracts. This forecast was used as input into the P-MArea production costing model for development of forecasted information.

2 Nuclear Fuel

The Nuclear Fuel Forecast model was used to project fuel costs. The 2010 Fuel Cost Projections used in the impending rate case filing are consistent with the Approved Operating Schedule dated August 15, 2008.

Supporting Schedules: Recap Schedules: E-10, C-40

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Line No. (1) (2) (3)

VIII. OPERATIONS AND MAINTENANCE AND CAPITAL EXPENDITURES FORECAST ASSUMPTIONS

A. INFLATION RATE FORECAST

See Section II. Inflation Rate Forecast

B. PAY PROGRAMS

1 Merit Pay Program Increases

2%

IX OTHER ASSUMPTIONS

A. Amount of CWIP and NFIP in Rate Base - FPSC

1. CWIP: All Construction Work in Progress (CWIP) which does not meet the criteria for the accrual of Allowance for Funds Used During Construction (AFUDC) are included in CWIP for rate base in accordance with Rule No. 25-6.0141, Florida Administrative Code.
2. NFIP: All Nuclear Fuel in Process is included in rate base.

B. Amount of CWIP and NFIP in Rate Base - FERC

1. CWIP: None.
2. NFIP: None.

C. AFUDC Rates for Capital Expenditures (FPSC and FERC)

FPL's current AFUDC rate is 7.65% as approved by the Florida Public Service Commission in Order No. PSC-08-0265-PAA-EI, in Docket No. 080088-EI issued on April 28, 2008.

D. AFUDC Debt/Equity Split - FPSC and FERC

	FPSC Ratio	FERC Ratio
1. Debt %	25.10%	34.61%
2. Equity %	74.90%	65.39%

Supporting Schedules:

Recap Schedules: E-10, C-40

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(1)	(2)	(3)	(4)

IX. E. Depreciation Rates

1. For the 2010 test year, depreciation expense is based on depreciation rates approved by the Florida Public Service Commission in Docket No. 050188-EI, Order No. PSC-05-0902-S-EI issued on September 14, 2005. Depreciation Rates specifically applicable to Manatee Unit 3 and Martin Unit 8 were approved in Docket No. 050300-EI, Order No. PSC-05-0821-PAA-EI issued on August 11, 2005, Turkey Point Unit 5 was approved in Docket No. 070100-EI, Order No. PSC-07-0456-PAA-EI issued on May 29, 2007, and the DeSoto and Space Coast solar energy centers were approved in Docket No. 080543-EI, Order No. PSC-08-0731-PAA-EI issued on November 3, 2008.
2. The Company has filed its current depreciation study as required in Rule No. 25-6.0436, Florida Administrative Code. The Company filed its previous study on March 17, 2005 and is required to file its next depreciation study no later than four years from the date it submitted its previous study.
3. The Company is requesting a company adjustment to its 2010 test period results to reflect the final outcome of the FPSC's review and approval of its recently filed depreciation study.
4. For the 2010 test year, FPL included an accrual of $15,321,113 for the Dismantlement of Fossil-Fueled Generating Stations. This annual amount was approved by the Commission in Order No. PSC-08-0095-PAA-EI in Docket No. 070378-EI issued on February 14, 2008.
5. The Company has filed its current dismantlement study as required in Order No. PSC-08-0095-PAA-EI in Docket No. 070378-EI issued on February 14, 2008. The Commission required FPL to file its next dismantlement study concurrently with the filing of its next depreciation study, which must be on or by March 17, 2009.
6. The Company is requesting a company adjustment to its 2010 test period results to reflect the final outcome of the FPSC's review and approval of its recently filed dismantlement study.

F. Total Line Losses **2010** **of Net Energy for Load**
6.23%

G. Company Usage **2010** **of Net Energy for Load**
0.11%

H. 35% **FEDERAL INCOME TAX RATE (REGULAR)**

I. 5.5% **STATE INCOME TAX RATE**

J. 0.00072 **REGULATORY ASSESSMENT FEE RATE (FPSC)**
Per Rule 25-6.0131,"Investor Owned Electric Company Regulatory Assessment Fee" in the Florida Administrative Code.

Supporting Schedules:

Recap Schedules: E-10, C-40

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 080677-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_ Projected Test Year Ended 12/31/10
____ Prior Year Ended ___/___/___
____ Historical Test Year Ended ___/___/___

Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl

	(1)	(2)	(3)
K.	2.50%	**GROSS RECEIPTS TAX RATE**	
		Provided as a pass through to customers as provided in Florida Statute Chapter 203.	
L.		**FRANCHISE FEE RATE**	
	4.72%	**2009**	
	4.73%	**2010**	
	4.75%	**2011**	
		Percentage represents composite rate.	
M.	**PRIOR YEAR**		
		Year 2009 Forecast	
N.	**TEST YEAR**		
		Year 2010 Forecast	
O.	**HISTORICAL YEAR**		
		Year 2008	
P.	**LAST MONTH OF HISTORICAL DATA**		
		September 2008	
Q.	**MILLAGE RATE FOR PROPERTY TAXES**		
		The overall millage rate used for historical, prior, test, and subsequent year are as follows:	
		2008	1.7080855%
		2009	1.7764089%
		2010	1.8297012%
		2011	1.8662952%

Supporting Schedules:

Recap Schedules: E-10, C-40

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COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

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Type of Data Shown:
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____ Prior Year Ended ___/___/___
____ Historical Test Year Ended ___/___/___

Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl

Line No.		(1)	(2)
1	R.	**STATUTORY SALES TAX RATE**	
2			6.00% Is the statutory sales tax rate. This may be coupled with a sur-tax that is levied by the County from 1/2% up to 1 1/2%.
3			6.20% is the blended forecasted rate, based on 2007 actual payments.
4			
5	S.	**FEDERAL AND STATE UNEMPLOYMENT TAX RATES**	
6			0.8% FUTA on the first $7,000 of wage base per employee
7			0.6% SUTA on the first $7,000 of wage base per employee
8			
9	T.	**FICA TAX RATES**	
10			6.2% Social Security Tax on $102,000 wage base for 2008 and on $106,800 wage base for 2009, 2010, 2011.
11			1.5% Medicare tax on total compensation.

Supporting Schedules: Recap Schedules: E-10, C-40

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_X_ Proj. Subsequent Yr Ended 12/31/11

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 080677-EI

Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl

(1) (2) (3) (4) (5) (6) (7) (8) (9)

I. SALES, CUSTOMERS, NET ENERGY FOR LOAD

GENERAL ASSUMPTIONS

	2011
A. Population (Florida)	19,212,055
B. Florida Non-Agricultural Employment (000's)	8,053
C. Florida Real Household Disposable Income (Base 2000) (000's of Dollars)	72
D. FPL Service Territory Cooling Degree Hours (Base 72 Degree Temperature)	1,947
E. FPL Service Territory Heating Degree Hours (Base 66 Degree Temperature)	355
F. FPL Service Territory Average Temperature Summer Peak Day (Fahrenheit)	85
G. FPL Service Territory Average Temperature Winter Peak Day (Fahrenheit	46

H. 2011 Sales by Revenue Class - Most likely (In Million KWH)

Residential	Commercial	Industrial	Street & Highway	Other Authority	Railway	Total Retail	Sales For Resale	Total [1]
51,654	46,620	3,656	457	35	91	102,514	2,252	104,765

I. 2011 Customers by Revenue Class

Residential	Commercial	Industrial	Street & Highway	Other Authority	Railway	Total Retail	Sales For Resale	Total [1]
4,056,428	534,717	12,980	3,255	188	23	4,607,590	4	4,607,594

J. 2011 Net Change in Customers by Revenue Class

Residential	Commercial	Industrial	Street & Highway	Other Authority	Railway	Total Retail	Sales For Resale	Total [2]
45,590	12,913	294	40	-5	0	58,832	0	58,832

[1] Totals may not add-up due to rounding.
[2] Average customers - sum of the projected customers for each month divided by twelve.

Supporting Schedules: Recap Schedules: E-10, C-40

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Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl

Line No.			(1)	(2)	
1	I.	K.	**Most Likely Forecast of Monthly Net Energy for Load (Million KWH**		
2				**2011**	
3			**January**	8,095	
4			**February**	7,400	
5			**March**	8,244	
6			**April**	8,654	
7			**May**	9,524	
8			**June**	10,540	
9			**July**	10,975	
10			**August**	11,189	
11			**September**	10,847	
12			**October**	9,685	
13			**November**	8,544	
14			**December**	8,229	
15				111,926	
16					
17		L.	**Most Likely Forecast of System Monthly Peaks (Megawatts**		
18				**2011**	
19			**January**	19,120	
20			**February**	15,696	
21			**March**	16,435	
22			**April**	17,645	
23			**May**	19,632	
24			**June**	20,404	
25			**July**	21,091	
26			**August**	21,368	
27			**September**	20,913	
28			**October**	19,489	
29			**November**	17,011	
30			**December**	15,956	
31					
32	II.	**INFLATION RATE FORECAST**			
33			**Most Likely Annual**		
34			**Rates of Change**		
35			**2011**		
36		A.	2.1%		**Consumer Price Index (CPI)**
37					The CPI Measures the price change of a constant market basket of goods and services over time
38					For company purposes it is a useful escalator for determining trends in wage contracts and income
39					payments, excluding construction work.

Supporting Schedules: | Recap Schedules: E-10, C-40

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		(1)	(2)
II.	B.	2.5%	**GDP Deflator** The GDP deflator is the broadest of all categories and captures price trends for the four majoi macro-economic sectors in the nation, which are: the household sector, the business sector, the government sector and the foreign sector. The GDP deflator tends to be more stable than the other indices and is used where very broad price trends are needed.
	C.	1.1%	**Producer Price Index** **(PPI): All Commodities** The PPI for all commodities is a comprehensive measure of the average changes in price received in primary markets by producers of commodities in all stages of processing. This index represents price movements in the manufacturing, agriculture, forestry, fishing, mining, gas and electricity, and public utilities sector of the economy
	D.	1.2%	**Producer Price Index** **(PPI) Intermediate Materials** PPI for Intermediate Materials reflects changes in the prices of commodities that have been processed but require further processing before being sold to the final user
	E.	1.2%	**Producer Price Index** **(PPI) Finished Producer Goods** PPI for Finished Producer Goods reflects changes in the prices of two major components: finished consumer goods and capital equipment received by producers
	F.	3.1%	**Producer Price Index** **Public Utility Private Fixed Investment (except telecom** PPI for Public Utility Private Fixed Investment (except telecom) reflects changes in the prices for fixed investment including investment in power plants, distribution lines, substations, transmission lines, and local natural gas pipelines
	G.	3.8%	**Compensation Per Hour (Non-Farm Business Sector)** **Index: All workers, including pension and benefits** The compensation per hour index reflects the changes in total wage and benefit compensation for non farm business labor

Supporting Schedules:

Recap Schedules: E-10, C-40

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Line No. (1) (2) (3)

III. FINANCING AND INTEREST RATE ASSUMPTIONS

General Assumptions

A. Target Capitalization Ratios
During the projected test year, Florida Power & Light Company's capitalization is projected to be as follows: equity approximately 55%, and debt approximately 45%, adjusted for off-balance sheet obligations

B. Preferred Stock Premium and Underwriting Discount
It is assumed that no preferred stock will be issued.

C. First Mortgage Bond Prices and Underwriting Discount
It is assumed that first mortgage bonds will be issued to the public at par with an underwriting commission of .875%.

Interest Rate Assumptions

	2011
D. Long Term Debt	7.0%
Short Term Debt	Although the company maintains several lines of credit, the company forecasts them at zero
E. Pollution Control Bonds	2.1%
F. Preferred Stock	No preferred stock outstanding.
G. 30-Day Commercial Paper	3.0%

Supporting Schedules: Recap Schedules: E-10, C-40

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DOCKET NO.: 080677-EI

Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl

Line No.		(1)	(2)	(3)	
1	IV.	**IN SERVICE DATES OF MAJOR PROJECTS**			
2	A.				
3		**BUDGET**		**IN SERVICE**	
4		**ITEM #**	**PROJECT DESCRIPTION**	**DATE ***	
5			**Nuclear Generation Projects**		
6		406	Turkey Point Excellence Program	2009-2012	(Multiple Projects with Various In-Service Dates)
7		398	St. Lucie Unit 2 Extended Power Uprate Project**	01/2011 & 06/2012	
8		399	Turkey Point Unit 4 Extended Power Uprate Project**	05/2011 & 12/2012	
9		556	St. Lucie & Turkey Point Life Cycle Management Project	U1-11/2011 & U2-12/2010	
10		392	St. Lucie Unit 1 Extended Power Uprate Project**	12/2011	
11		410	St. Lucie Corrosion & Coatings Project	12/2011	
12		617	National Fire Protection Assoc 805 Project	PSL-12/2011 & PTN-12/2012	
13		393	Turkey Point Unit 3 Extended Power Uprate Project**	05/2012	
14		528	Turkey Point Integrated Bottom Mount Instrument Project	05/2012	
15		410	St. Lucie Procedure Upgrade Project	12/2012	
16			**Fossil Generation Projects**		
17		152	West County Energy Center Unit 3 Project	06/2011	
18		138	Sanford Unit 5 LP HRSG Evap Section Replacement Project	09/2011	
19		177	Scherer Unit 4 Select Catalytic Reduction CAIR Project**	04/2012	
20		177	Scherer Unit 4 Flue Gas Desulfer FGD CAIR Project**	04/2012	
21		506	Cape Canaveral Modernization	06/2013	
22		493	Intrastate Gas Pipeline Project	09/2013	
23		505	Riviera Modernization	06/2014	
24			**Other Generation Projects**		
25		151	St. Lucie Wind Project	05/2011	
26			**Transmission Projects**		
27		277	Princeton Injection Project	05/2011	
28		287	Princeton Injection North Area Project	12/2011	
29		291	Bunnell-St.Johns 230kv Line	12/2011	
30		294	Norris Volusia Line	12/2011	
31		325	Bobwhite Manatee 230kv Line	12/2011	
32		349	Hobe-Sandpiper #2 Transmission Line	12/2011	
33		524	Martin South Bay Conversion West Area Project	11/2011	
34		524	Martin South Bay Conversion Central Area Project	12/2013	
35		391	Collier Area Improvements Project	12/2013	
36		414	South Ft. Myers Reliability Standard Project	12/2013	
37		313	Green Project	06/2015	
38			**Intangible & General Plant Projects**		
39		164	SAP Project	09/2011	
40		587	SCC EMS Project	12/2013	
41					
42		* Projects which have a foreseeable monetary impact in fiscal year 2011			
43		** Projects which are recovered, or partially recovered, through other mechanisms			

Supporting Schedules:

Recap Schedules: E-10, C-40

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Line No.	(1)	(2)	(3)	(4)	(5)
1	**V. MAJOR GENERATING UNIT OUTAGE ASSUMPTIONS**				
2					
3	**A. Nuclear Maintenance Schedules (including outage period and reason)**				
4					
5		**2011**		**2011**	
6	**Unit**	**Outage Period**		**Outage Description**	
7	St. Lucie Unit 1	10/1/2011 - 12/4/2011		Refueling, Extended Power Uprate Project	
8	Turkey Point Unit 4	3/14/2011 - 5/23/2011		Refueling, Extended Power Uprate Project	
9					
10					
11	**B. Fossil Units Outage Schedule (including outage period and reason)**				
12					
13		**2011**	**2011**		**2011**
14	**Unit**	**Outage Start**	**Outage End**		**Outage Description**
15	FT. MYERS 2	2/12/11	2/25/11		C HGP, MINOR HRSG, GEN INSP
16	FT. MYERS 2	1/29/11	2/11/11		D HGP, MINOR HRSG, GEN INSP
17	FT. MYERS 2	2/12/11	2/25/11		E HGP, MINOR HRSG, GEN INSP
18	LAUDERDALE 4	3/19/11	3/27/11		A /B COMBUSTOR INSPECTION
19	LAUDERDALE 5	10/29/11	11/22/11		A MAJOR CT, MINOR HRSG, GEN INSP
20	LAUDERDALE 5	10/29/11	11/6/11		B COMBUSTOR INSPECTION
21	LAUDERDALE 5	10/29/11	11/25/11		TURBINE VALVES, GEN INSP / STATOR REWEDGE
22	MANATEE 1	2/1/11	2/21/11		DC REPAIRS
23	MANATEE 2	10/1/11	11/4/11		MINOR BOILER, TURBINE VALVES
24	MANATEE 3	3/5/11	3/25/11		A MAJOR CT & HRSG, GEN INSP
25	MANATEE 3	3/5/11	3/25/11		B MAJOR CT & HRSG, GEN INSP
26	MANATEE 3	3/26/11	4/15/11		C MAJOR CT & HRSG, GEN INSP
27	MANATEE 3	3/26/11	4/15/11		D MAJOR CT & HRSG, GEN INSP
28	MANATEE 3	3/19/11	4/8/11		TURBINE VALVES, GEN INSP
29	MARTIN 8	9/3/11	9/23/11		A MAJOR CT & HRSG, GEN INSP
30	MARTIN 8	5/14/11	5/20/11		B HRSG INSPECTION
31	MARTIN 8	6/4/11	6/24/11		C MAJOR CT & HRSG, GEN INSP
32	MARTIN 8	6/4/11	6/24/11		D MAJOR CT & HRSG, GEN INSP
33	MARTIN 8	6/4/11	6/24/11		TURBINE VALVES, GEN INSP

Supporting Schedules: Recap Schedules: E-10, C-40

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Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl

Line No.	(1)	(2)	(3)	(4)	(5)
1	V. B.				
2	MARTIN 2	10/22/11	11/25/11		MAJOR BOILER, TURBINE VALVES, GEN INSP
3	MARTIN 3	3/26/11	4/15/11		A MAJOR CT & HRSG, GEN INSP
4	MARTIN 3	7/9/11	7/15/11		B COMBUSTOR INSPECTION
5	MARTIN 4	2/19/11	2/25/11		A COMBUSTOR INSPECTION
6	MARTIN 4	2/12/11	3/4/11		B MAJOR CT & HRSG, GEN INSP
7	MARTIN 4	2/12/11	2/25/11		GEN INSP
8	PT EVERGLADES 3	4/23/11	6/11/11		MAJOR BOILER, TURBINE VALVES, GEN INSP / P-HOUSE
9	PUTNAM	9/1/11	9/5/11		COOLNG TOWER FAN
10	PUTNAM 1	10/15/11	10/24/11		1GT1 HOT GAS PATH & MINOR HRSG
11	PUTNAM 1	9/1/11	9/5/11		1GT2 COMBUSTOR INSPECTION
12	PUTNAM 2	1/1/11	1/31/11		2GT1 GENERATOR MAJOR
13	PUTNAM 2	2/1/11	2/5/11		2GT2 COMBUSTOR INSPECTION
14	PUTNAM 2	3/14/11	5/8/11		MAJOR STM TURBINE & GEN / SWITCHGEAR
15	SANFORD 5	6/11/11	6/24/11		A HGP, MINOR HRSG, GEN INSP / 24K / S0-S5 REPLACE
16	SANFORD 5	5/28/11	6/10/11		B HRSG INSPECTION / S0-S5 REPLACE
17	SANFORD 5	4/16/11	4/22/11		C HRSG INSPECTION
18	SANFORD 5	9/3/11	9/23/11		D MAJOR CT, HRSG, & GEN / 24K
19	SANFORD 5	4/16/11	6/24/11		MAJOR STM TURBINE & GEN / P-91 /SWITCHGEAR
20	ST. JOHNS RIVER POWER PARK 1	2/26/11	3/28/11		BLR,FGD,BFPT
21	TURKEY POINT 5	2/26/11	3/4/11		A HRSG INSPECTION
22	TURKEY POINT 5	3/5/11	3/11/11		B HRSG INSPECTION
23	TURKEY POINT 5	3/25/11	3/31/11		C HRSG INSPECTION
24	TURKEY POINT 5	4/1/11	4/7/11		D HRSG INSPECTION
25	TURKEY POINT 1	4/2/11	4/22/11		MINOR BOILER
26	WEST COUNTY ENERGY CENTER 1	10/1/11	10/20/11		1A HGP, MINOR HRSG, GEN INSP
27	WEST COUNTY ENERGY CENTER 1	10/21/11	11/9/11		1B HGP, MINOR HRSG, GEN INSP
28	WEST COUNTY ENERGY CENTER 1	11/10/11	11/29/11		1C HGP, MINOR HRSG, GEN INSP
29	WEST COUNTY ENERGY CENTER 2	3/12/11	3/21/11		2A COMBUSTOR INSPECTION
30	WEST COUNTY ENERGY CENTER 2	3/22/11	3/31/11		2B COMBUSTOR INSPECTION
31	WEST COUNTY ENERGY CENTER 2	4/1/11	4/10/11		2C COMBUSTOR INSPECTION

Supporting Schedules:

Recap Schedules: E-10, C-40

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DOCKET NO.: 080677-EI

Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl

Line No. (1) (2) (3) (4)

VI. INTERCHANGE AND PURCHASED POWER ASSUMPTIONS

A. Contractual Commitments for Scheduled Interchange/Purchased Power

1 Unit Power Purchase (UPS) - Southern Companies

a. Capacity (MW) based on 2004 Net Dependable Capacity Unit Ratings:

2011	932

b. Minimum (MW) scheduling requirements

2011	82

c. Capacity and energy costs based on Southern's estimate, subject to true up and audit.

d. Energy costs recovered through Fuel Cost Recovery Clause (FCRC) and capacity costs recovered through Capacity Cost Recovery Clause (CCRC).

2 Unit Power Purchase - St Johns River Power Park

a. 30% of rated net capacity of each unit is considered purchased power.
b. All energy scheduled by FPL in excess of 20% (FPL owned generation) is considered purchased energy.
c. Capacity costs are recovered through CCRC and base rates. Energy costs are recovered through FCRC.

Supporting Schedules:

Recap Schedules: E-10, C-40

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Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl

Line No. (1) (2) (3) (4)

3 Power Sold and Economy Energy Purchases (Schedule "OS")

a. Schedule OS sales based upon projected market prices and expected available generation relative to FPL's projected incremental cost of sale (generation and transmission)

b. Schedule OS purchases based upon FPL's projected incremental generation cost relative to projected market prices plus incremental costs and transmission.

c. Energy & transmission costs of OS purchases recovered through the FCRC. For OS sales, FCRC credited for incremental generation cost, CCRC credited for FPL transmission incurred to make sale, Base credited for incremental costs of running gas turbines, if applicable, and FCRC credited for gain on sale

4 Interchange related to St Lucie Unit 2 Reliability Exchange agreement

a. Based on P-MArea projection for PSL 1 and PSL 2 output as applied to the contract formula.

5 Schedule of New and Expiring Interchange/Purchase Power Contracts for the period.

6 Purchased Power from Qualifying Facilities:

		Capacity (MW)	Energy (MWH)
a. Firm			
	2011	595	4,511,676
b. As Available			
	2011	n/a	448,604

Supporting Schedules:

Recap Schedules: E-10, C-40

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DOCKET NO.: 080677-EI

Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl

Line No. (1) (2) (3)

VI. 7 Schedule of Sales and Purchased Power Contracts for the Period (contracts impact 2011)

a. Sales: Key West 45 MW RTC Capacity and Energy (1/1/11 to 12/31/11)
Reedy Creek 8 MW Call option on Capacity and Incremental Energy (1/1/11 to 12/31/11)
Lee County EMC Partial Requirements up to 300 MW (1/1/11 to 12/31/11)
Homestead 2 MW Call Option on Capacity and Incremental Energy (1/1/11 to 12/31/11)
Florida Keys Coop Partial Requirements ~119 MW (1/1/2011 to 12/31/2011)

b. Purchases: Oleander Power Project, LP dated April 30, 2001 (6/1/2002 through 5/31/2012)

VII. FUEL ASSUMPTIONS

A. Fuel Related Assumptions

1 Fossil Fuel

The current real and nominal fuel price forecast for light and heavy fuel oil, natural gas, coal, and petroleum coke, and the projection for the availability of natural gas to the FPL system for 2009, 2010 and 2011 were issued on November 6, 2008 and were based on current and projected market conditions, and existing supply and transportation contracts. This forecast was used as input into the P-MArea production costing model for development of forecasted information.

2 Nuclear Fuel

The Nuclear Fuel Forecast model was used to project fuel costs. The 2011 Fuel Cost Projections used in the impending rate case filing are consistent with the Approved Operating Schedule dated August 15, 2008.

Supporting Schedules: Recap Schedules: E-10, C-40

DOCKET NO. 080677-EI
MFR F-8 MAJOR FORECAST ASSUMPTIONS
EXHIBIT REB-4, PAGE 24 OF 28

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_ Proj. Subsequent Yr Ended 12/31/11

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 080677-EI

Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl

Line No. (1) (2) (3)

VIII. OPERATIONS AND MAINTENANCE AND CAPITAL EXPENDITURES FORECAST ASSUMPTIONS

A. INFLATION RATE FORECAST

See Section II. Inflation Rate Forecast

B. PAY PROGRAMS

1 Merit Pay Program Increases

2%

IX OTHER ASSUMPTIONS

A. Amount of CWIP and NFIP in Rate Base - FPSC

1. CWIP: All Construction Work in Progress (CWIP) which does not meet the criteria for the accrual of Allowance for Funds Used During Construction (AFUDC) are included in CWIP for rate base in accordance with Rule No. 25-6.0141, Florida Administrative Code.
2. NFIP: All Nuclear Fuel in Process is included in rate base.

B. Amount of CWIP and NFIP in Rate Base - FERC

1. CWIP: None.
2. NFIP: None.

C. AFUDC Rates for Capital Expenditures (FPSC and FERC)

FPL's current AFUDC rate is 7.65% as approved by the Florida Public Service Commission in Order No. PSC-08-0265-PAA-EI, in Docket No. 080088-EI issued on April 28, 2008.

D. AFUDC Debt/Equity Split - FPSC and FERC

	FPSC Ratio	FERC Ratio
1. Debt %	25.10%	34.61%
2. Equity %	74.90%	65.39%

Supporting Schedules:

Recap Schedules: E-10, C-40

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_ Proj. Subsequent Yr Ended 12/31/11

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 080677-EI

Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl

Line No.			(1)	(2)	(3)	(4)
1	IX.	E.	**Depreciation Rates**			
2			1. For the 2011 subsequent year, depreciation expense is based on depreciation rates approved by the Florida Public Service Commission in Docket No. 050188-EI, Order No.			
3			PSC-05-0902-S-EI issued on September 14, 2005. Depreciation Rates specifically applicable to Manatee Unit 3 and Martin Unit 8 were approved in Docket No. 050300-EI, Order No.			
4			PSC-05-0821-PAA-EI issued on August 11, 2005, Turkey Point Unit 5 was approved in Docket No. 070100-EI, Order No. PSC-07-0456-PAA-EI issued on May 29, 2007, and the DeSoto			
5			and Space Coast solar energy centers were approved in Docket No. 080543-EI, Order No. PSC-08-0731-PAA-EI issued on November 3, 2008.			
6			2. The Company has filed its current depreciation study as required in Rule No. 25-6.0436, Florida Administrative Code. The Company filed its previous study on March 17, 2005			
7			and is required to file its next depreciation study no later than four years from the date it submitted its previous study.			
8			3. The Company is requesting a company adjustment to its 2011 subsequent period results to reflect the final outcome of the FPSC's review and approval of			
9			its recently filed depreciation study.			
10			4. For the 2011 subsequent year, FPL included an accrual of $15,321,113 for the Dismantlement of Fossil-Fueled Generating Stations. This annual amount was approved by the			
11			Commission in Order No. PSC-08-0095-PAA-EI in Docket No. 070378-EI issued on February 14, 2008.			
12			5. The Company has filed its current dismantlement study as required in Order No. PSC-08-0095-PAA-EI in Docket No. 070378-EI issued on February 14, 2008.			
13			The Commission required FPL to file its next dismantlement study concurrently with the filing of its next depreciation study, which must be on or by March 17, 2009.			
14			6. The Company is requesting a company adjustment to its 2011 subsequent period results to reflect the final outcome of the FPSC's review and approval of			
15			its recently filed dismantlement study.			
16						
17		F.	**Total Line Losses**		**2011**	**of Net Energy for Load**
18					**6.23%**	
19						
20		G.	**Company Usage**		**2011**	**of Net Energy for Load**
21					**0.11%**	
22		H.		35% **FEDERAL INCOME TAX RATE (REGULAR)**		
23						
24		I.		5.5% **STATE INCOME TAX RATE**		
25						
26		J.		0.00072 **REGULATORY ASSESSMENT FEE RATE (FPSC)**		
27				Per Rule 25-6.0131,"Investor Owned Electric Company Regulatory Assessment Fee" in the Florida Administrative Code.		
28						
29		K.		2.50% **GROSS RECEIPTS TAX RATE**		
30					Provided as a pass through to customers as provided in Florida Statute Chapter 203.	

Supporting Schedules:

Recap Schedules: E-10, C-40

DOCKET NO. 080677-EI
MFR F-8 MAJOR FORECAST ASSUMPTIONS
EXHIBIT REB-4, PAGE 26 OF 28

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_ Proj. Subsequent Yr Ended 12/31/11

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 080677-EI

Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl

Line No.		(1)	(2)
1			
2	**L.**		**FRANCHISE FEE RATE**
3		**4.75%**	**2011**
4			Percentage represents composite rate.
5			
6	**M.**	**PRIOR YEAR**	
7			Year 2009 Forecast
8			
9	**N.**	**TEST YEAR**	
10			Year 2010 Forecast
11			
12	**O.**	**HISTORICAL YEAR**	
13			Year 2008
14			
15	**P.**	**LAST MONTH OF HISTORICAL DATA**	
16			September 2008
17			
18	**Q.**	**LAST YEAR FORECASTED**	
19			Year 2011
20			
21	**R.**	**MILLAGE RATE FOR PROPERTY TAXES**	
22			1.8662952% is the overall millage rate used for the year ended 12/31/2011.

Supporting Schedules: Recap Schedules: E-10, C-40

DOCKET NO. 080677-EI
MFR F-8 MAJOR FORECAST ASSUMPTIONS
EXHIBIT REB-4, PAGE 27 OF 28

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. As a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
_X_ Proj. Subsequent Yr Ended 12/31/11

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 080677-EI

Witness: Dr. Rosemary Morley, Robert E. Barrett, Jr., Kim Ousdahl

Line No.	(1)	(2)
1	S.	**STATUTORY SALES TAX RATE**
2		6.00% Is the statutory sales tax rate. This may be coupled with a sur-tax that is levied by the County from 1/2% up to 1 1/2%.
3		6.20% is the blended forecasted rate, based on 2007 actual payments.
4		
5	T.	**FEDERAL AND STATE UNEMPLOYMENT TAX RATES**
6		0.8% FUTA on the first $7,000 of wage base per employee
7		0.6% SUTA on the first $7,000 of wage base per employee
8		
9	U.	**FICA TAX RATES**
10		6.2% Social Security Tax on $102,000 wage base for 2008 and on $106,800 wage base for 2009, 2010, 2011.
11		1.5% Medicare tax on total compensation.

Supporting Schedules:

Recap Schedules: E-10, C-40

DOCKET NO. 080677-EI
MFR F-8 MAJOR FORECAST ASSUMPTIONS
EXHIBIT REB-4, PAGE 28 OF 28

BUDGET AND ACTUAL NET INCOME 2004 - 2008

$ millions	Budget Net Income		Actual Net Income		Percent Change
2004	$773	(1)	$763	(2)	-1.3%
2005	$748	(1)	$748	(3)	0.0%
2006	$829	(1)	$829	(4)	0.0%
2007	$838	(1)	$836	(3)	-0.2%
2008	$875	(1)	$789	(3)	-9.8%
Average 2004-2008					-2.3%
Average 2004-2007					-0.4%

(1) Source: Company records

(2) Source: FPL Group, Inc. Form 10-K; excludes impact of hurricanes and settlement of shareholder lawsuit

(3) Source: FPL Group, Inc. Form 10-K

(4) Source: FPL Group, Inc. Form 10-K, excludes $27 million of after tax disallowed storm costs

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 57
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Robert E. Barrett, Jr. (REB-5)
DATE 08/28/09

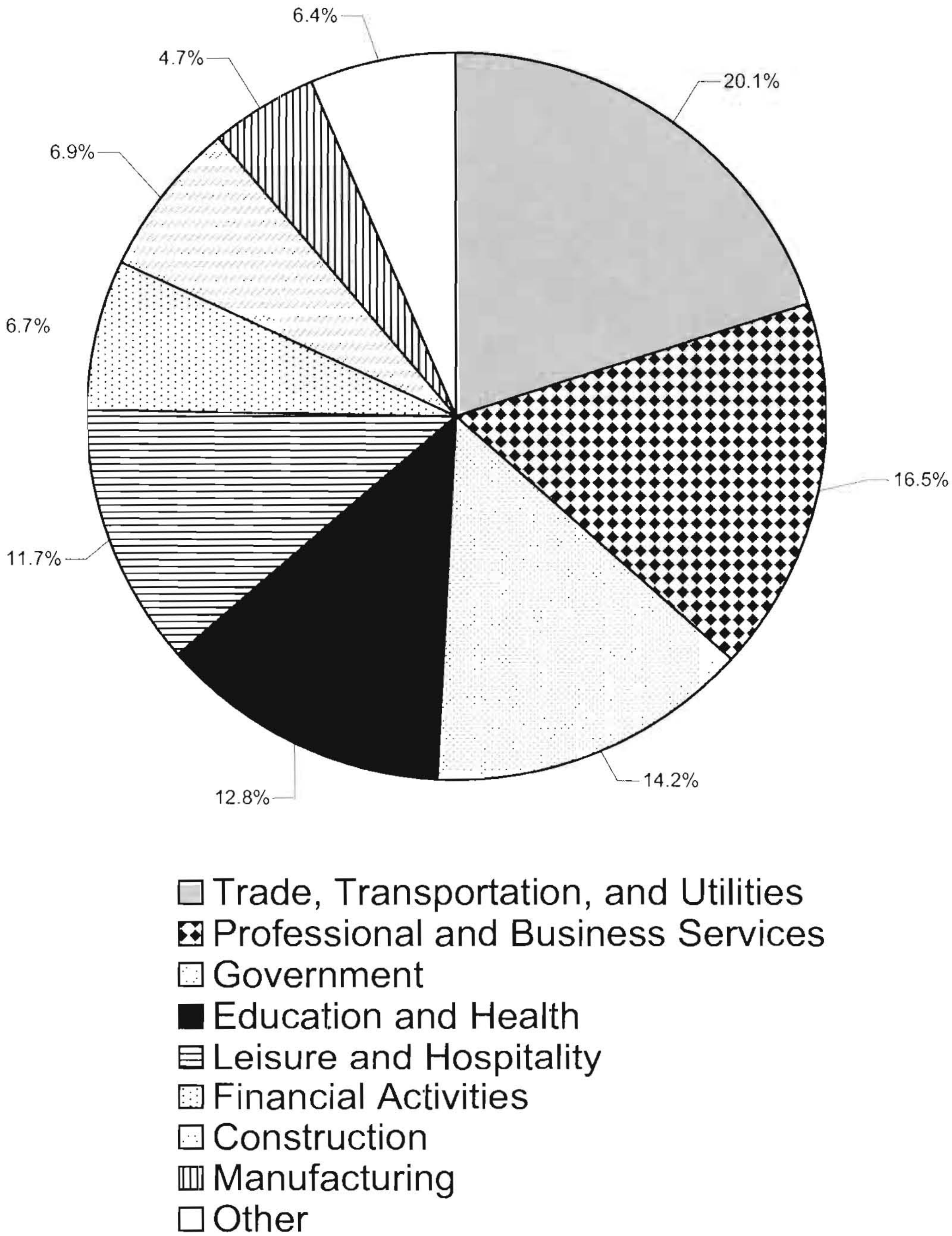
2007 Gross State Product (Selected States)
Millions of chained (2000) dollars

Rank	United States	13,743,021	100.0%
1	California	1,812,968	13.2%
2	Texas	1,141,965	8.3%
3	New York	1,103,024	8.0%
4	Florida	734,519	5.3%
5	Illinois	609,570	4.4%
6	Pennsylvania	531,110	3.9%
7	Ohio	466,309	3.4%
8	New Jersey	465,484	3.4%
9	North Carolina	399,446	2.9%
10	Georgia	396,504	2.9%

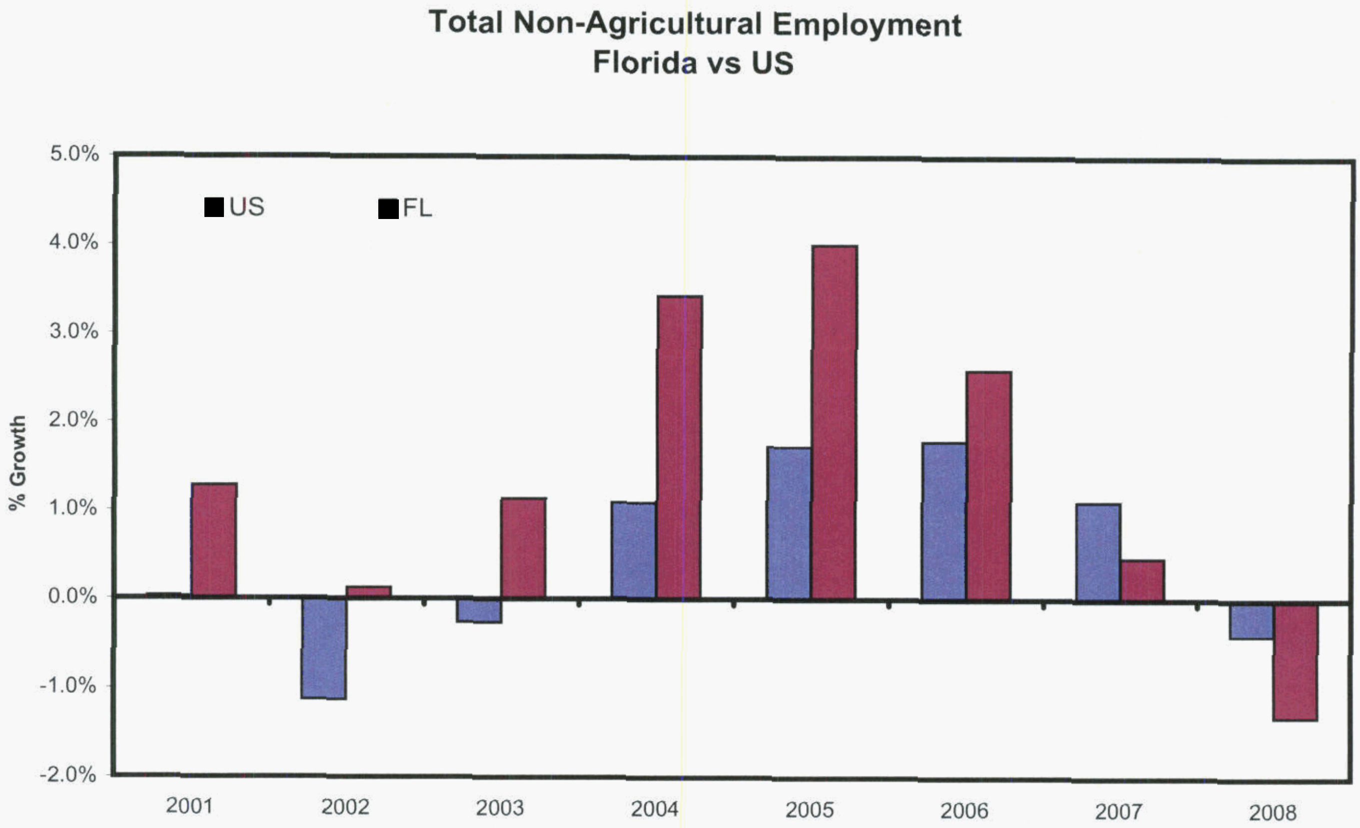
Source: U.S. Bureau of Economic Analysis

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 58
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Robert E. Barrett, Jr. (REB-6)
DATE 08/28/09

2008 Florida Employment Structure



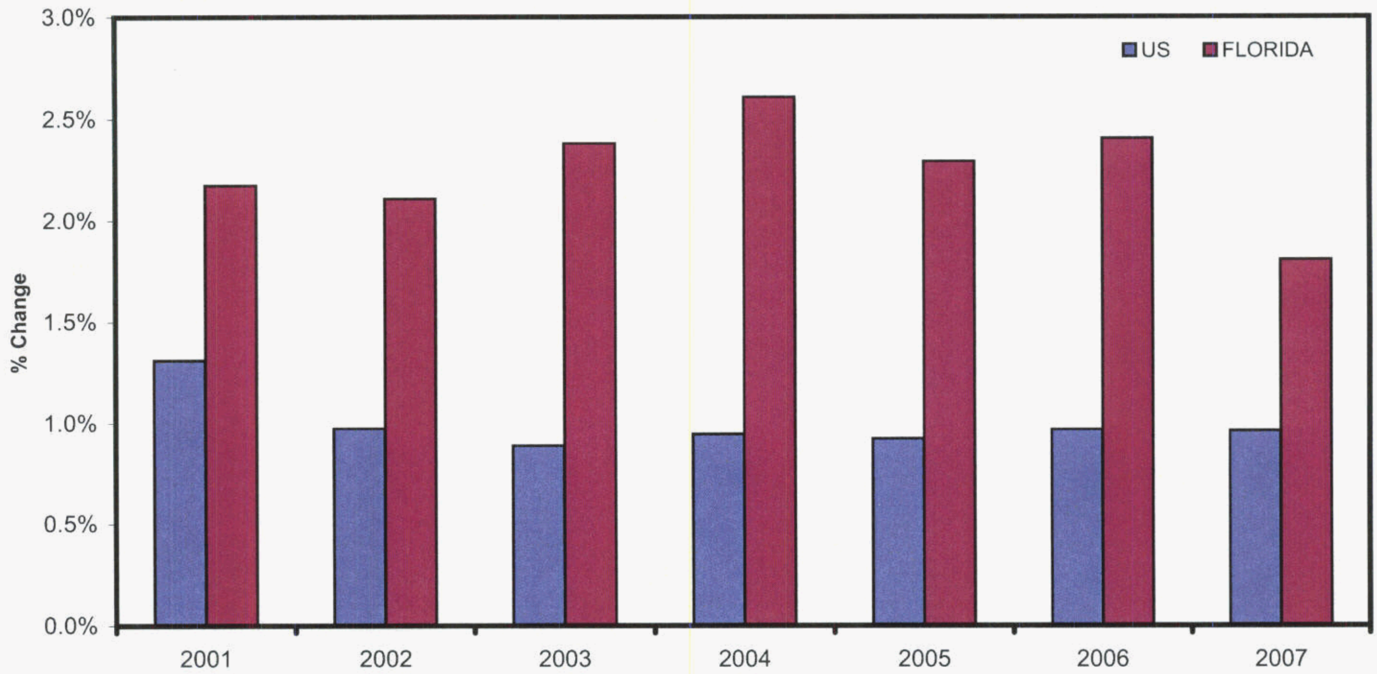
Source: Global Insight



Source: Bureau of Labor Statistics (BLS)

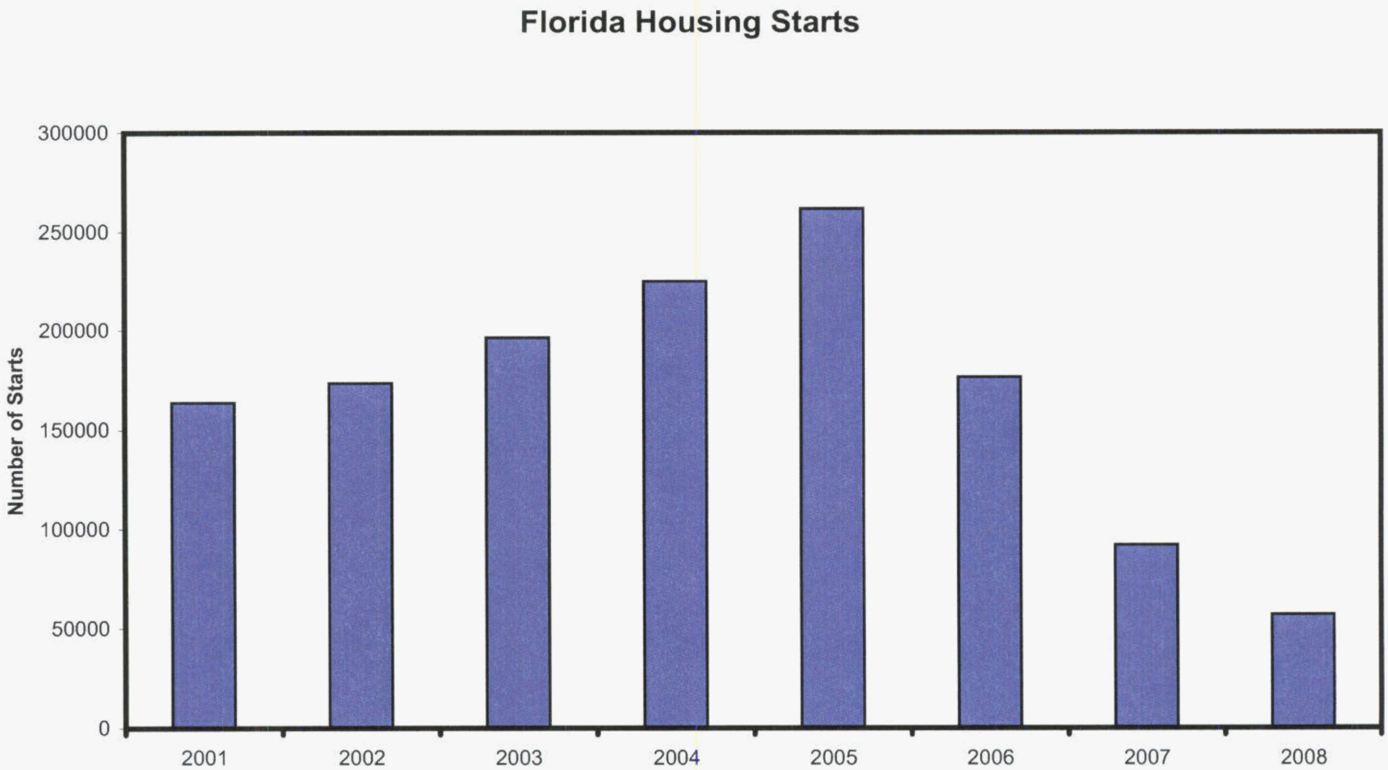
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 59
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Robert E. Barrett, Jr. (REB-7)
DATE 08/28/09

Population Growth Estimates



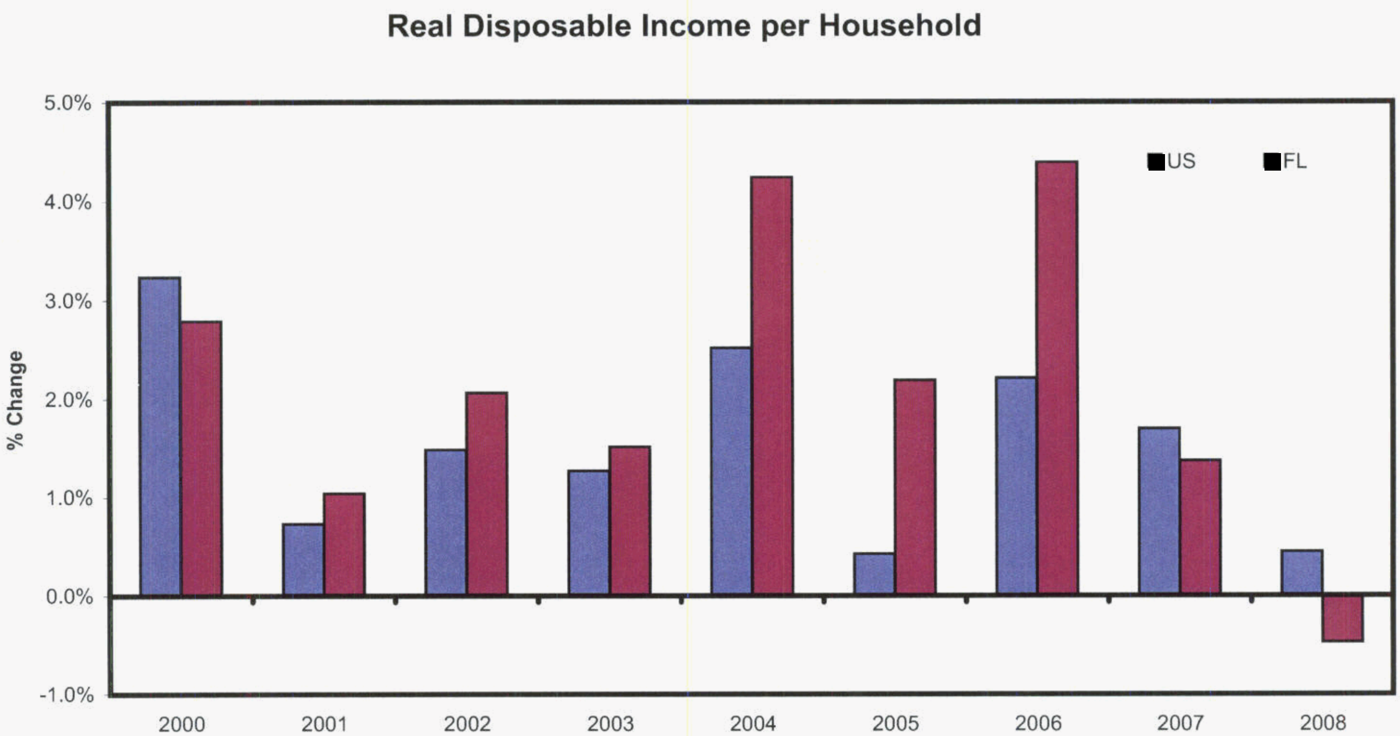
Source: US: Census Bureau.
FPL: University of Florida

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 60
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Robert E. Barrett, Jr. (REB-8)
DATE 08/28/09



Source: University of Florida

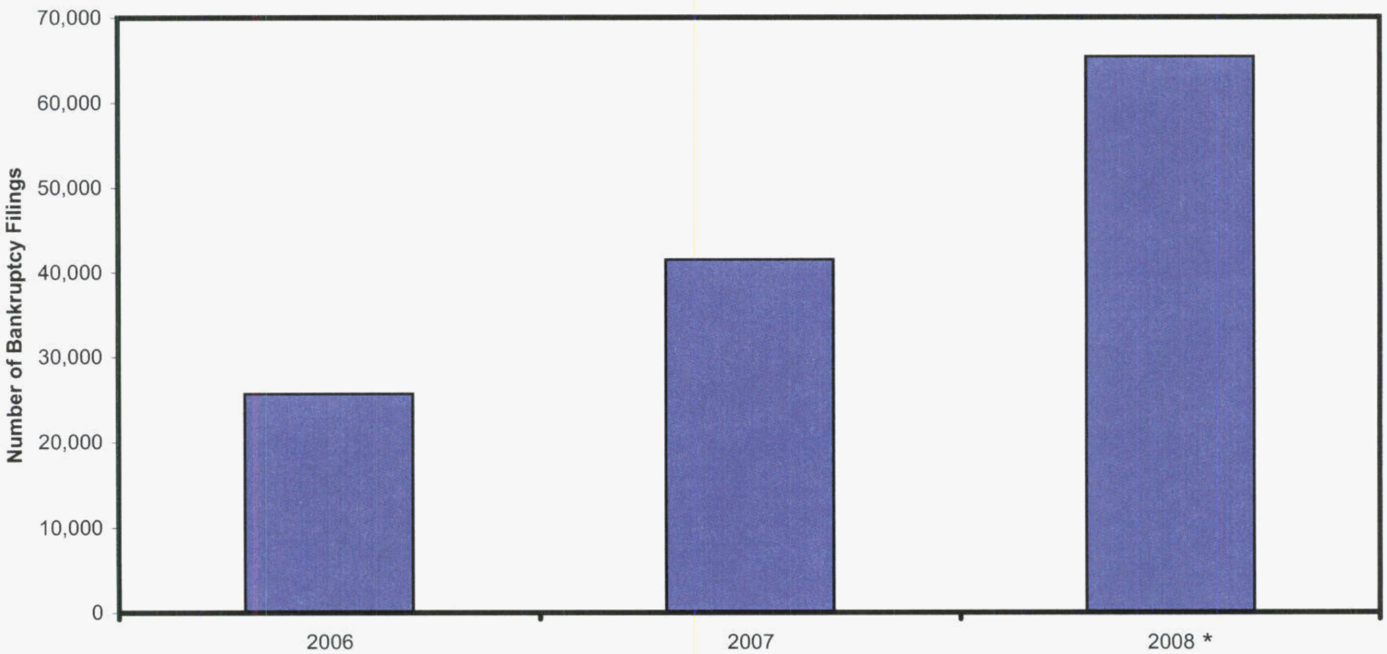
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 61
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Robert E. Barrett, Jr. (REB-9)
DATE 08/28/09



Source: US: Bureau of Economic Analysis (BEA) - FL: FPL

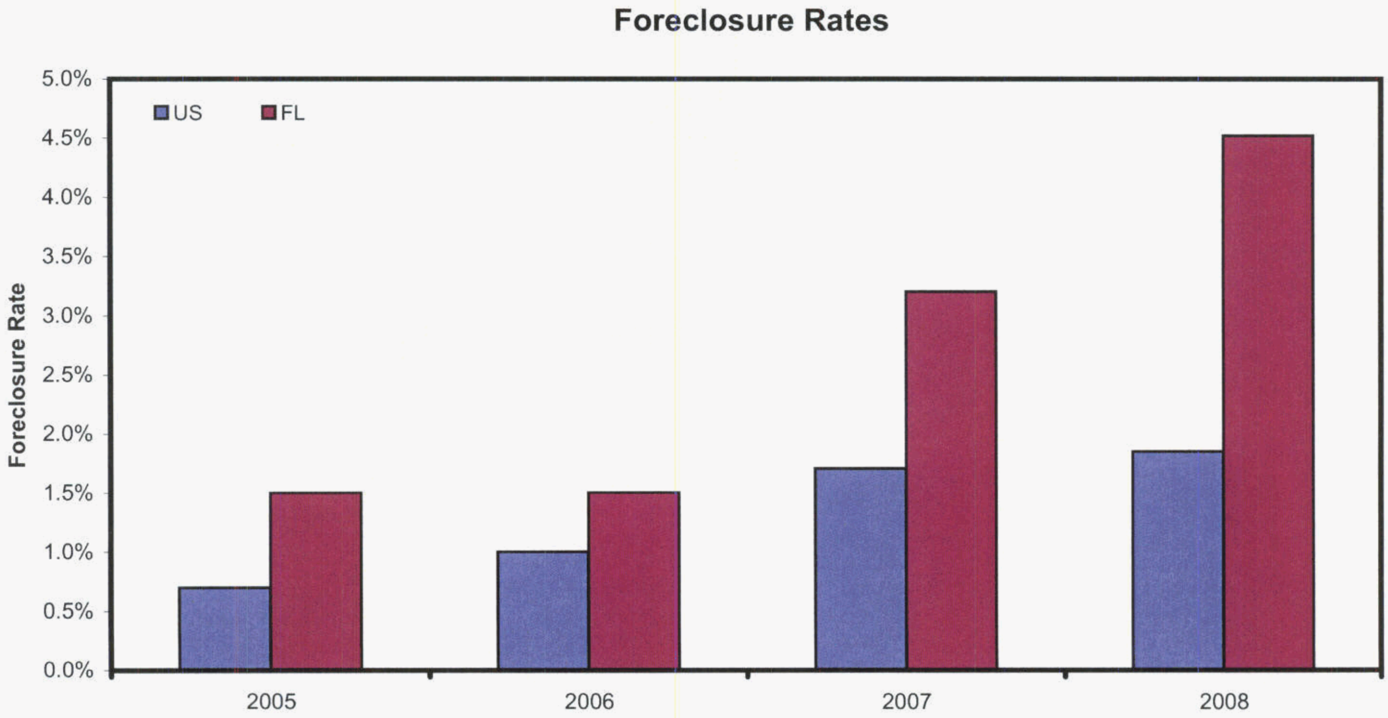
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 62
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Robert E. Barrett, Jr. (REB-10)
DATE 08/28/09

Florida Personal Bankruptcy Filings



Source: American Bankruptcy Institute
* Fourth quarter estimated

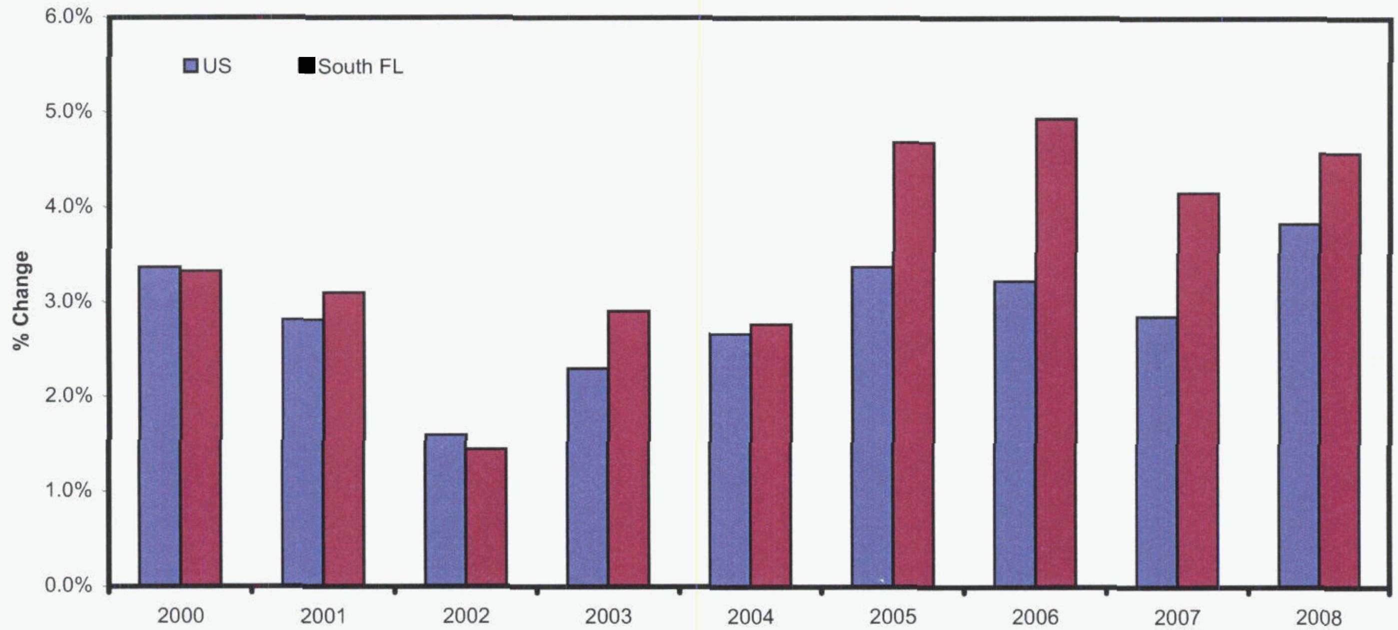
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 63
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Robert E. Barrett, Jr. (REB-11)
DATE 08/28/09



Source: RealtyTrac

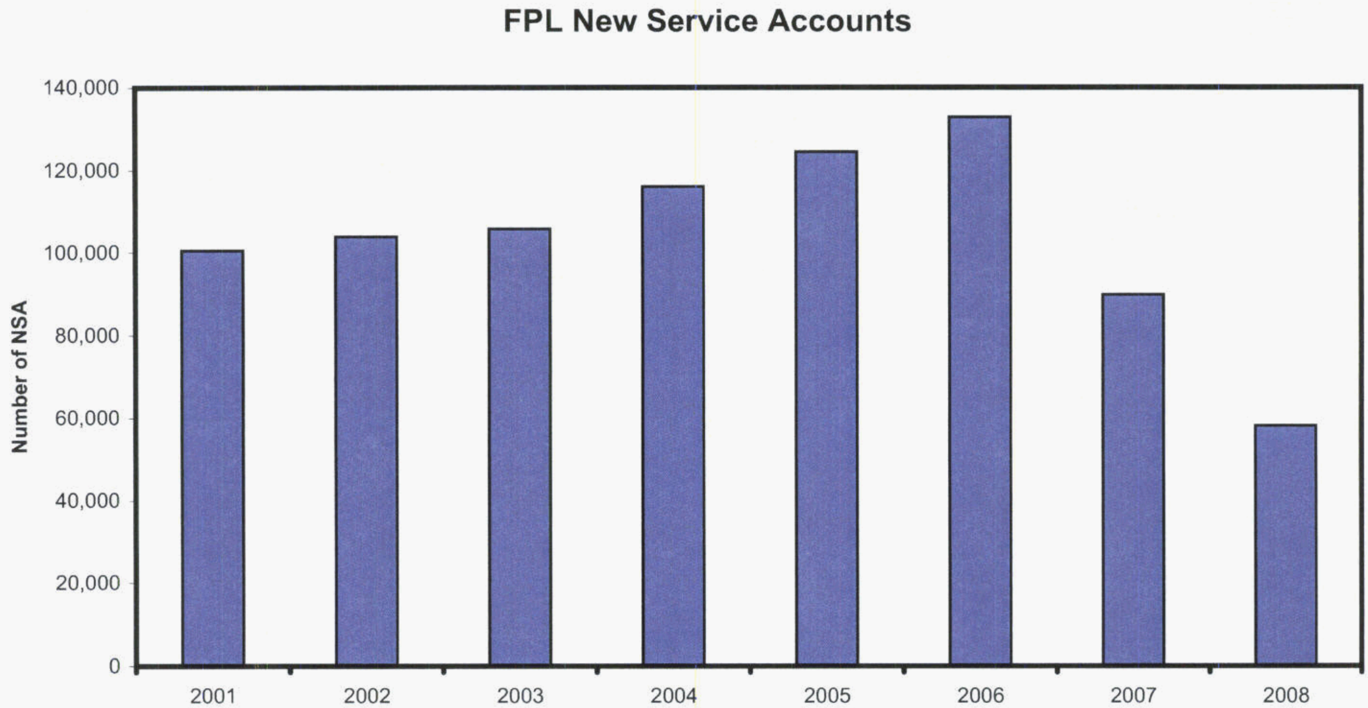
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 64
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Robert E. Barrett, Jr. (REB-12)
DATE 08/28/09

Consumer Price Index (All Urban Consumers)



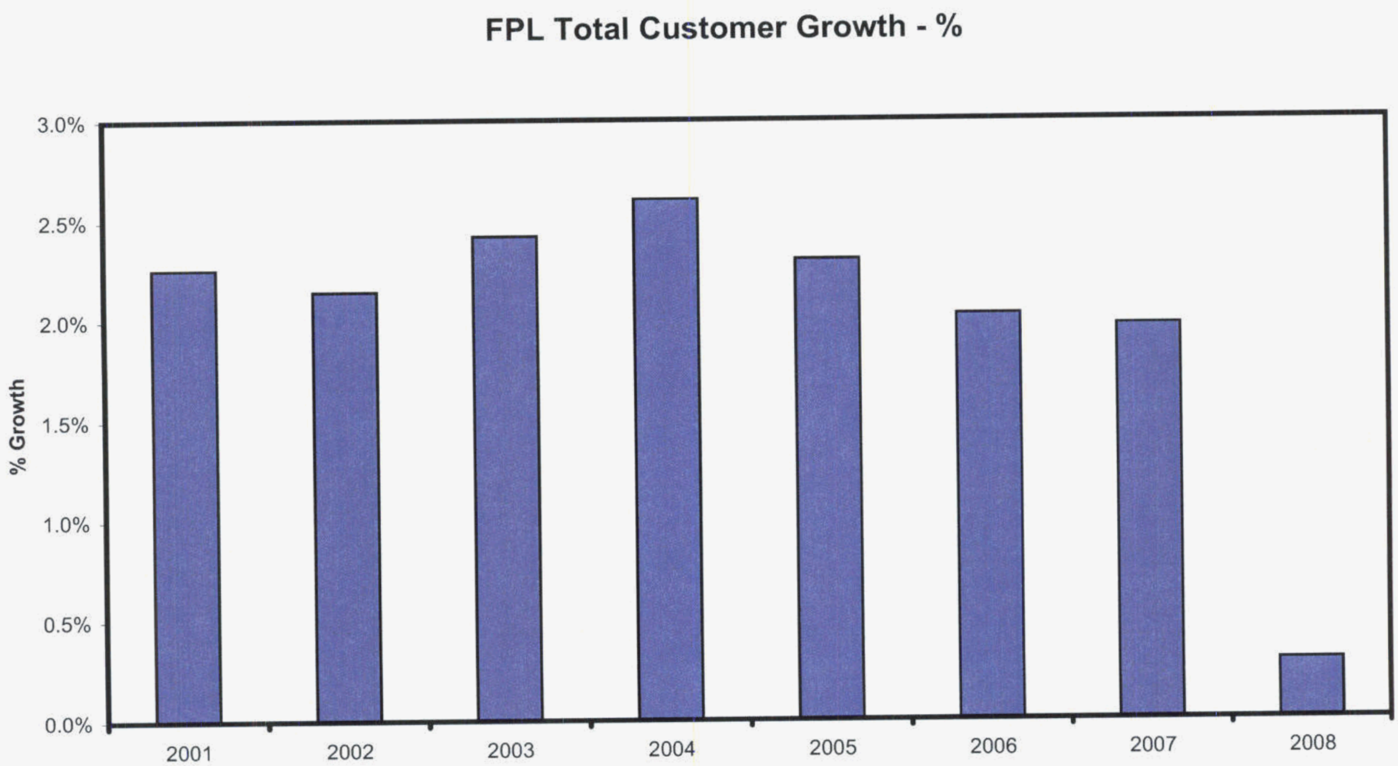
Source: Bureau of Labor Statistics (BLS)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 65
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Robert E. Barrett, Jr. (REB-13)
DATE 08/28/09



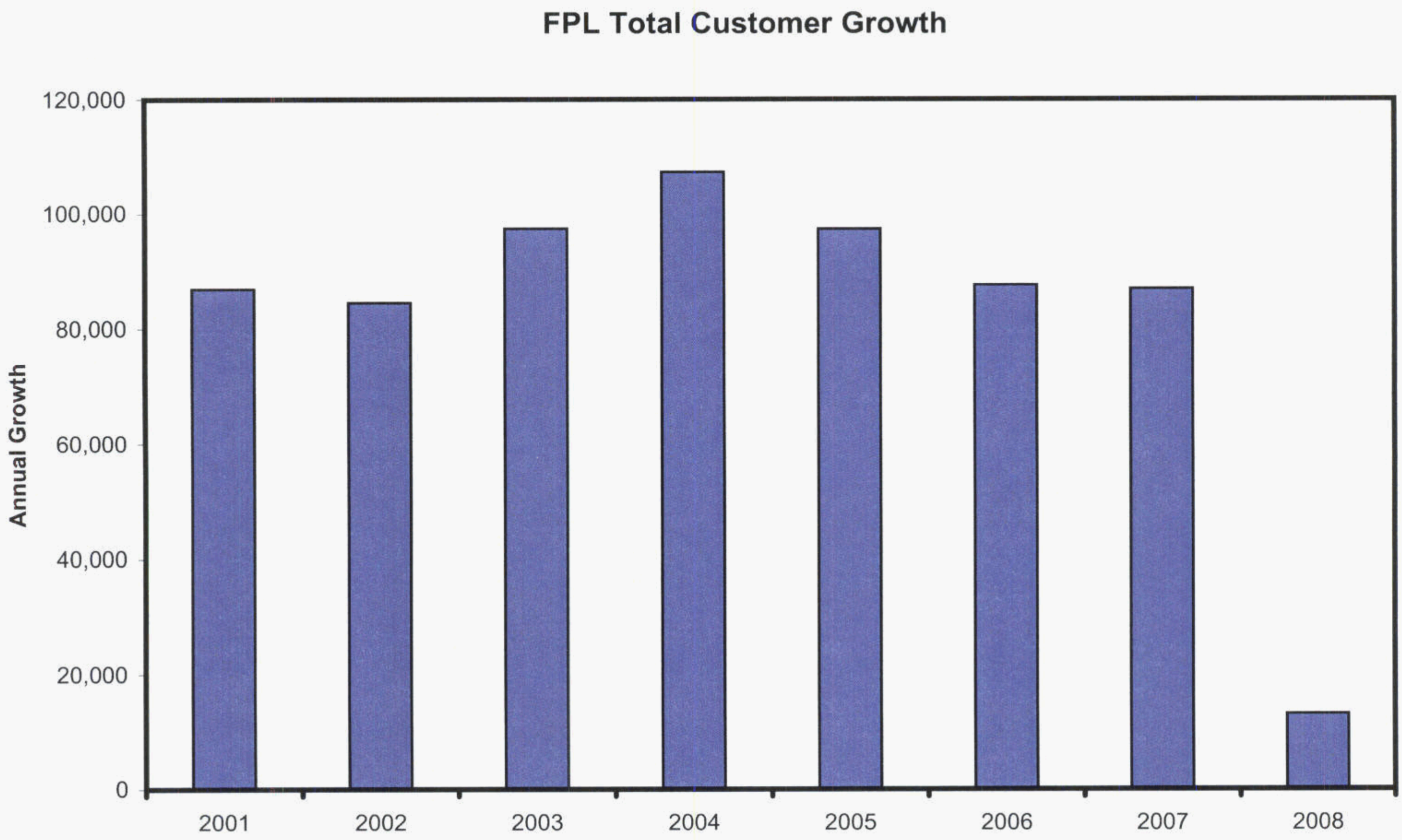
Source: FPL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI **EXHIBIT** 66
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Robert E. Barrett, Jr. (REB-14)
DATE 08/28/09



Source: FPL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 67
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Robert E. Barrett, Jr. (REB-15)
DATE 08/28/09


FPL Total Customer Growth
120,000
100,000
80,000
60,000
40,000
20,000
0
Annual Growth
2001
2002
2003
2004
2005
2006
2007
2008

Source: FPL

Capital Expenditure Reductions
Excludes New England Division
($millions)

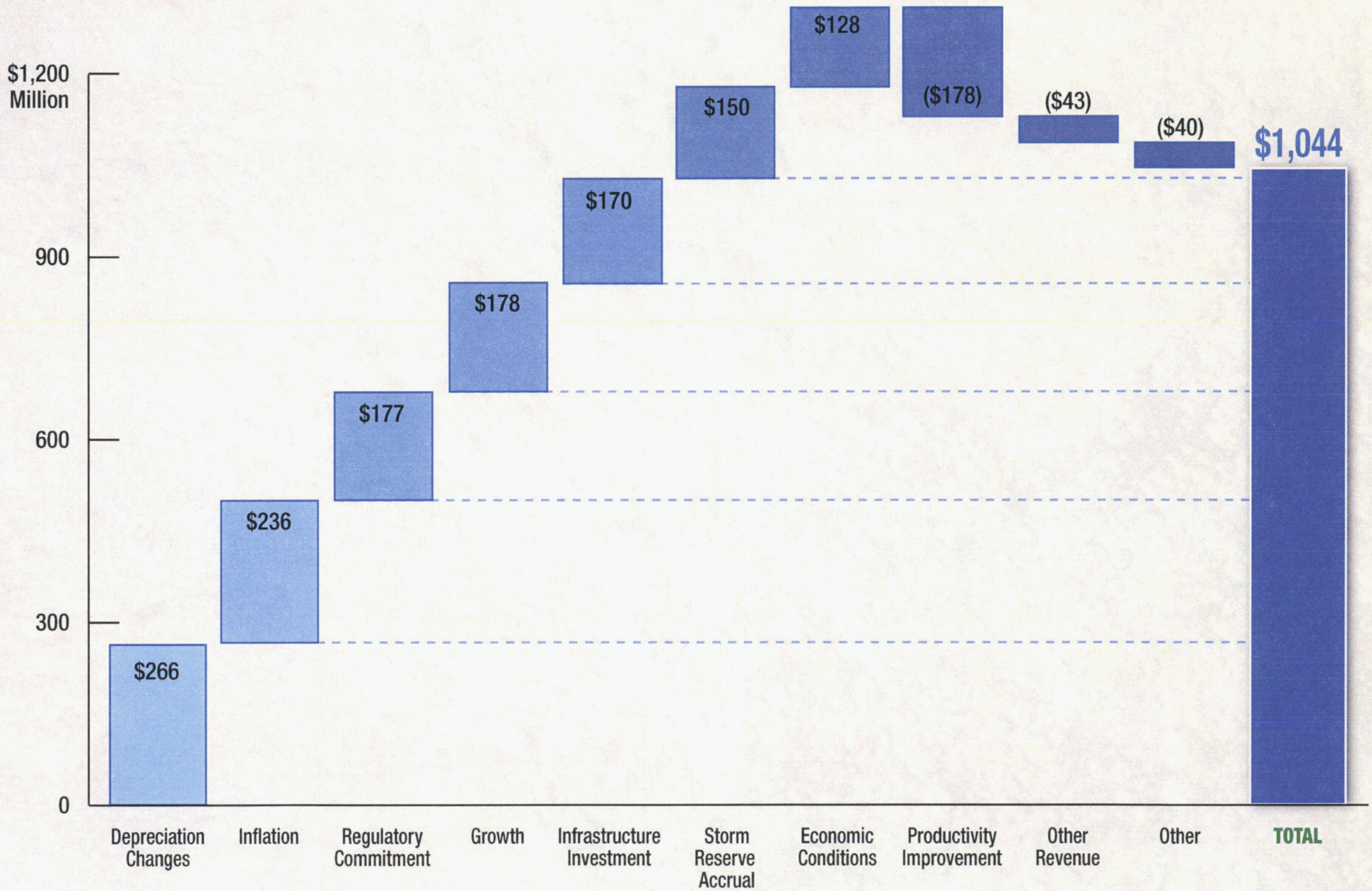
Business Unit	2008 Original Budget	2008 Year End Actual	2008 Increase (Decrease)	2009 Proposed Budget	2009 Approved Budget	2009 Increase (Decrease)
Power Generation	$ 463	$ 389	$ (74)	$ 418	$ 417	$ (1)
Nuclear	318	316	(2)	596	533	(63)
Transmission	303	259	(44)	281	225	(56)
Distribution	558	440	(118)	604	345	(259)
Customer Service	16	15	(1)	62	54	(8)
Engineering & Construction and Project Development	960	760	(199)	1,111	1,025	(86)
Other	231	138	(93)	187	191	4
Total	$ 2,848	$ 2,317	$ (531)	$ 3,259	$ 2,790	$ (469)

DOCKET NO. 080677-EI
Capital Expenditure Reductions
Exhibit REB-16 Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 68
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Robert E. Barrett, Jr. (REB-16)
DATE 08/28/09

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 69
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Robert E. Barrett, Jr. (REB-17)
DATE 08/28/09

Drivers of the Increase in Revenue Requirements 2010



Docket No. 080677-EI
Drivers of Increase in Revenue Requirements for 2010
Exhibit REB-17, Page 1 of 1

FPL Capital Expenditures
1985 through 2008
$ Billions

Capacity additions placed in service	
Production plant	$4.6
Transmission interconnection	0.2
Capacity additions in construction work in progress	1.0
Production plant - other	5.9
Transmission	3.2
Distribution	8.5
General	2.6
Total	$25.9

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 70
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Robert E. Barrett, Jr. (REB-18)
DATE 08/28/09

FLORIDA PUBLIC SERVICE COMMISSION

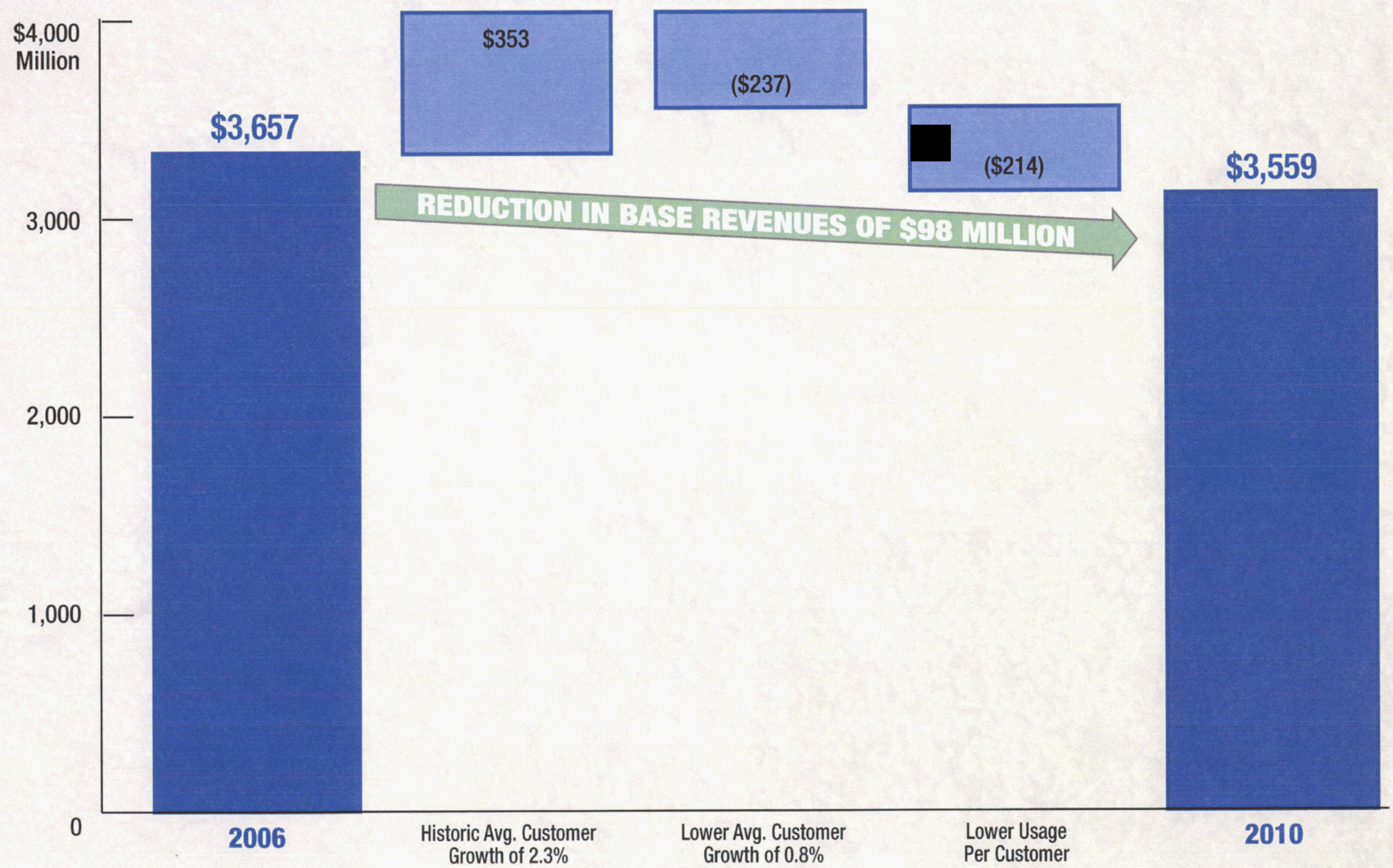
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 71

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS Robert E. Barrett, Jr. (REB-19)

DATE 08/28/09

Base Revenue Decline



Docket No. 080677-EI
Base Revenue Decline
2006-2010
Exhibit REB-19, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

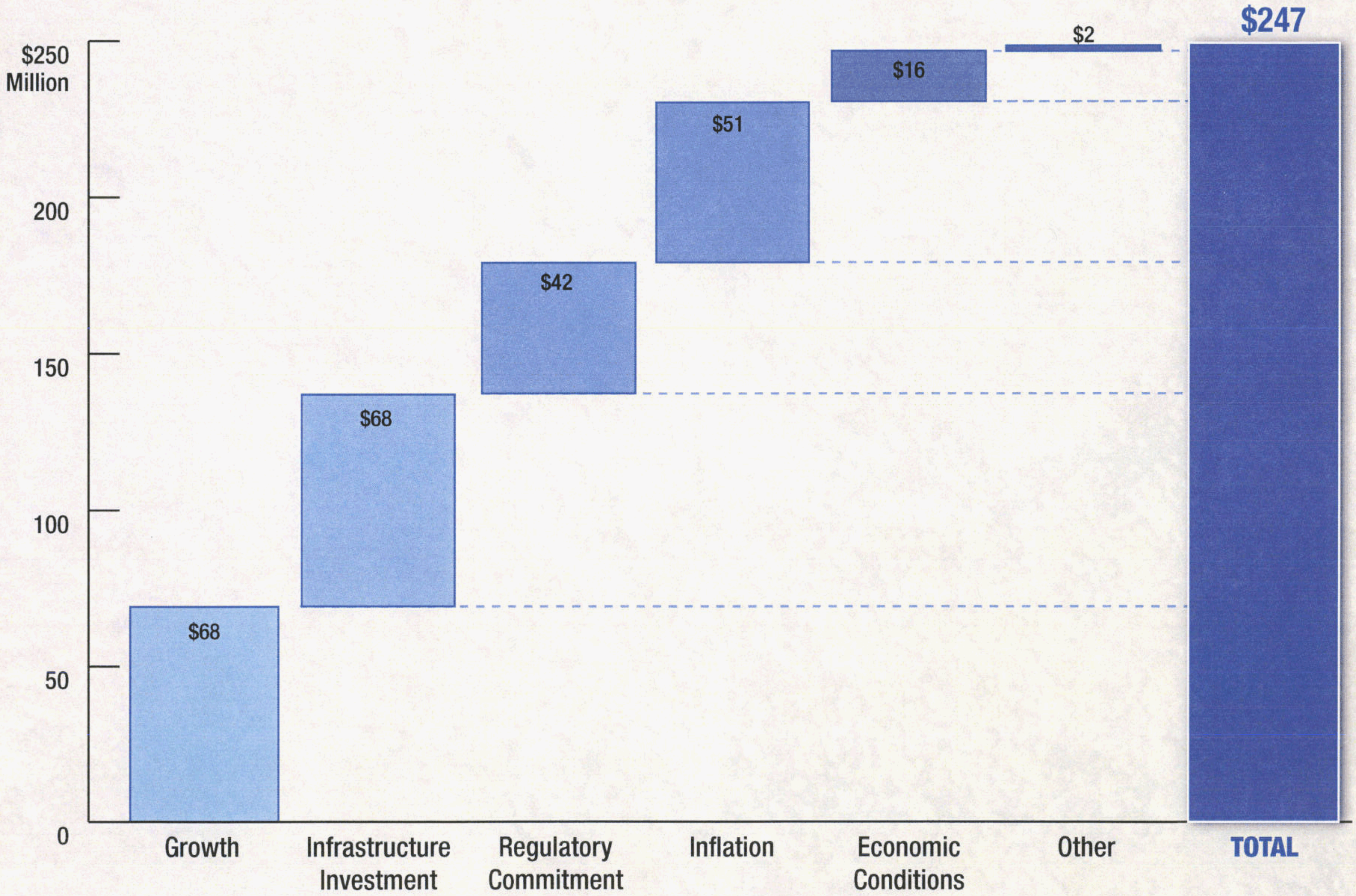
DOCKET NO. 080677-EI & 090130-EI **EXHIBIT** 72

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS Robert E. Barrett, Jr. (REB-20)

DATE 08/28/09

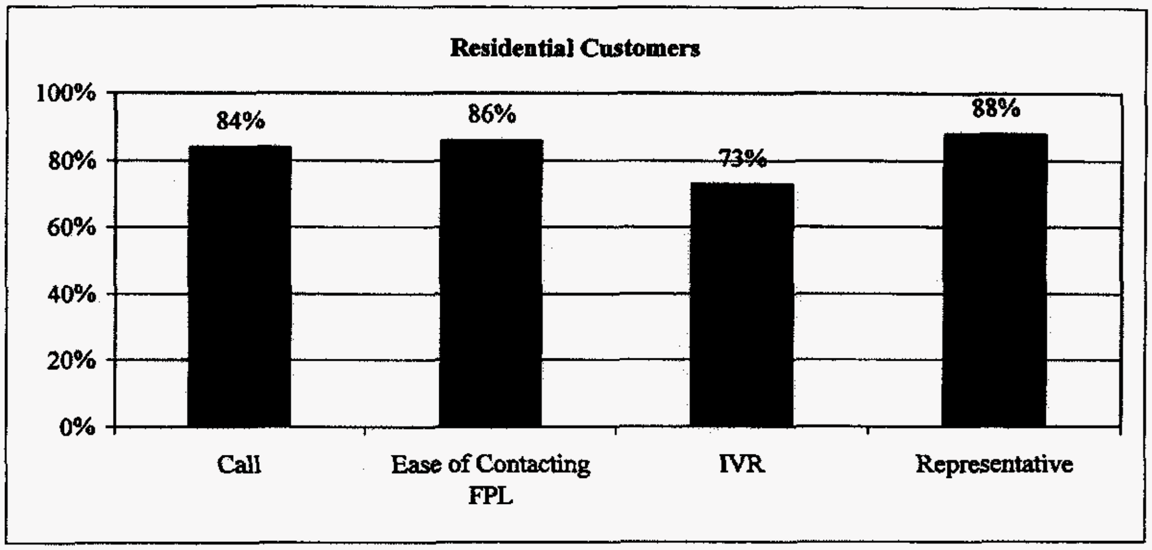
Drivers of the Increase in Revenue Requirements 2011

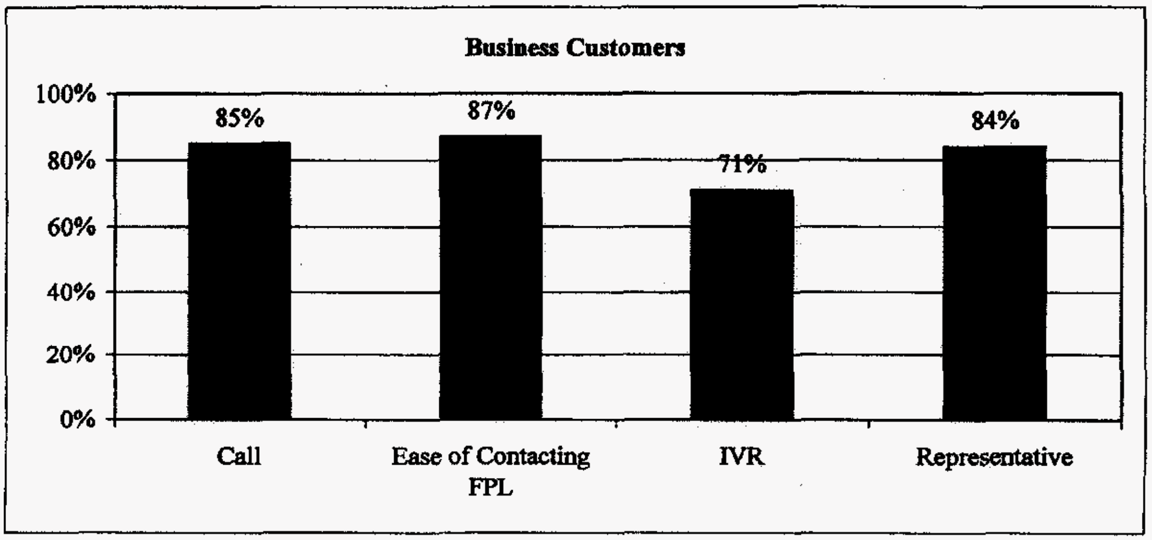


Docket No. 080677-EI
Drivers of Increase in Revenue Requirements for 2011
Exhibit REB-20, Page 1 of 1

2008 Customer Care Center Satisfaction Research
Key Satisfaction Measures

The satisfaction score is the percent of customers rating the area being measured a six or seven on a seven point scale, with seven indicating the highest level of satisfaction.





FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 73
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Marlene M. Santos (MMS-1)
DATE 08/28/09

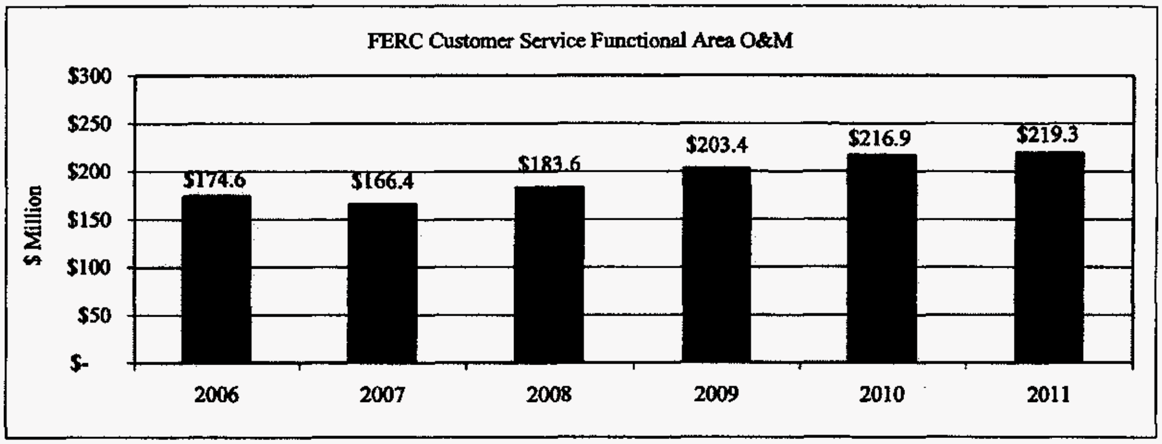
BILLING AND PAYMENT OPTIONS

Billing Options	Description	Number of 2008 Annual Transaction
US Mail Billing	Customer receives a bill via US Mail.	45,226,065
FPL E-Mail Bill	Customer receives an e-mail with a link to FPL.com, where they can view their bill.	6,229,160
E-Bill	Customer signs up with a third party to view bills from multiple companies through the internet. These bills may be viewed at a variety of internet web sites, including those of financial institutions, brokerage firms, United States Postal Service, etc.	1,485,259
EDI	FPL Electronic Data Interchange allows a business customer to receive their bill electronically.	529,349
Summary Billing	Customers with 10 or more service locations may receive one summarized bill instead of receiving individual bills throughout the month.	434,740

Payment Options	Description	Number of 2008 Annual Transaction
Pay by US Mail	Customer remits payment through the U.S Postal Service.	22,552,945
EDI Payment	FPL Electronic Data Interchange allows a business customer to pay their bill electronically.	8,713,957
Automatic Bill Pay	Customer pre-authorizes automatic transfer of payment from their checking accounts. Customers may choose between 10 to 20 days after the billing date to have their funds withdrawn.	7,722,691
Pay Online	Customer makes payments online at FPL.com. Payments may be made anytime, 24 hours a day, 7 days a week.	5,732,228
Pay Station	Customer pays in person at an authorized pay station.	4,546,286
Pay by Phone	Customer makes payments using a touch-tone telephone. Payments may be made anytime, 24 hours a day, 7 days a week.	4,152,828
Online Billing Payments	Customer signs up with a third party to view and pay bills from multiple companies through the internet. These bills may be viewed and paid at a variety of internet web sites, including those of financial institutions, brokerage firms, United States Postal Service, etc.	1,484,871
Credit or Debit Card	Customer makes a payment using a credit or debit card through a third party vendor.	483,831

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 74
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Marlene M. Santos (MMS-2)
DATE 08/28/09

FERC Customer Service O&M
($ Million)



FERC Customer Service O&M		2006		2007		2008		2009		2010		2011
Customer Accounts	$	127.1	$	131.8	$	149.3	$	159.1	$	169.5	$	168.0
Customer Service and Information	$	19.7	$	17.1	$	18.0	$	16.6	$	17.9	$	20.3
Sales	$	27.8	$	17.5	$	16.3	$	27.7	$	29.5	$	31.0
TOTAL	**$**	**174.6**	**$**	**166.4**	**$**	**183.6**	**$**	**203.4**	**$**	**216.9**	**$**	**219.3**

FERC Customer Service O&M by Key Activities

		2006		2007		2008		2009		2010		2011
Customer Service	$	110.4	$	114.6	$	119.1	$	125.9	$	132.6	$	137.9
Advance Metering Infrastructure	$	0.9	$	0.8	$	1.4	$	2.6	$	7.4	$	9.5
Uncollectible Expense	$	16.3	$	17.9	$	31.3	$	32.2	$	26.4	$	21.7
Sales	$	27.8	$	17.5	$	16.3	$	27.7	$	29.5	$	31.0
Other *	$	19.2	$	15.6	$	15.6	$	14.9	$	21.0	$	19.2
TOTAL	**$**	**174.6**	**$**	**166.4**	**$**	**183.6**	**$**	**203.4**	**$**	**216.9**	**$**	**219.3**

* Includes O&M expense incurred or associated with other FPL Business Units that relate to the operations of customer service (as defined by FERC)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 75
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Marlene M. Santos (MMS-3)
DATE 08/28/09

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080677-EI & 090130-EI EXHIBIT 76

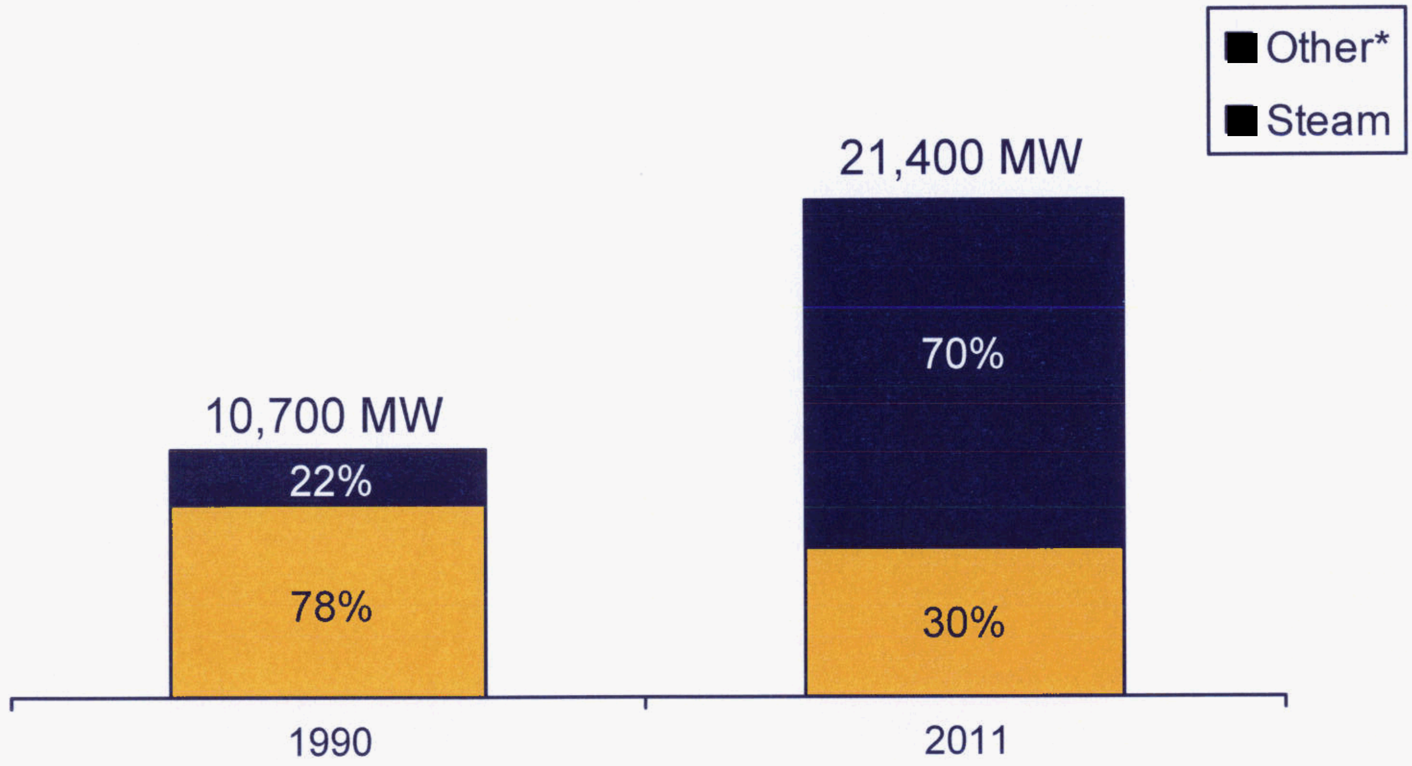
COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS George K. Hardy (GKH-1)

DATE 10/23/09

From 1990 to 2011, FPL's fossil capacity will have doubled and evolved from traditional "Steam" to modernized combustion turbine-based (i.e. "Other") technology

Changes in FPL Fossil Generating Capability
(by FERC "Steam" and "Other" Production Categories)



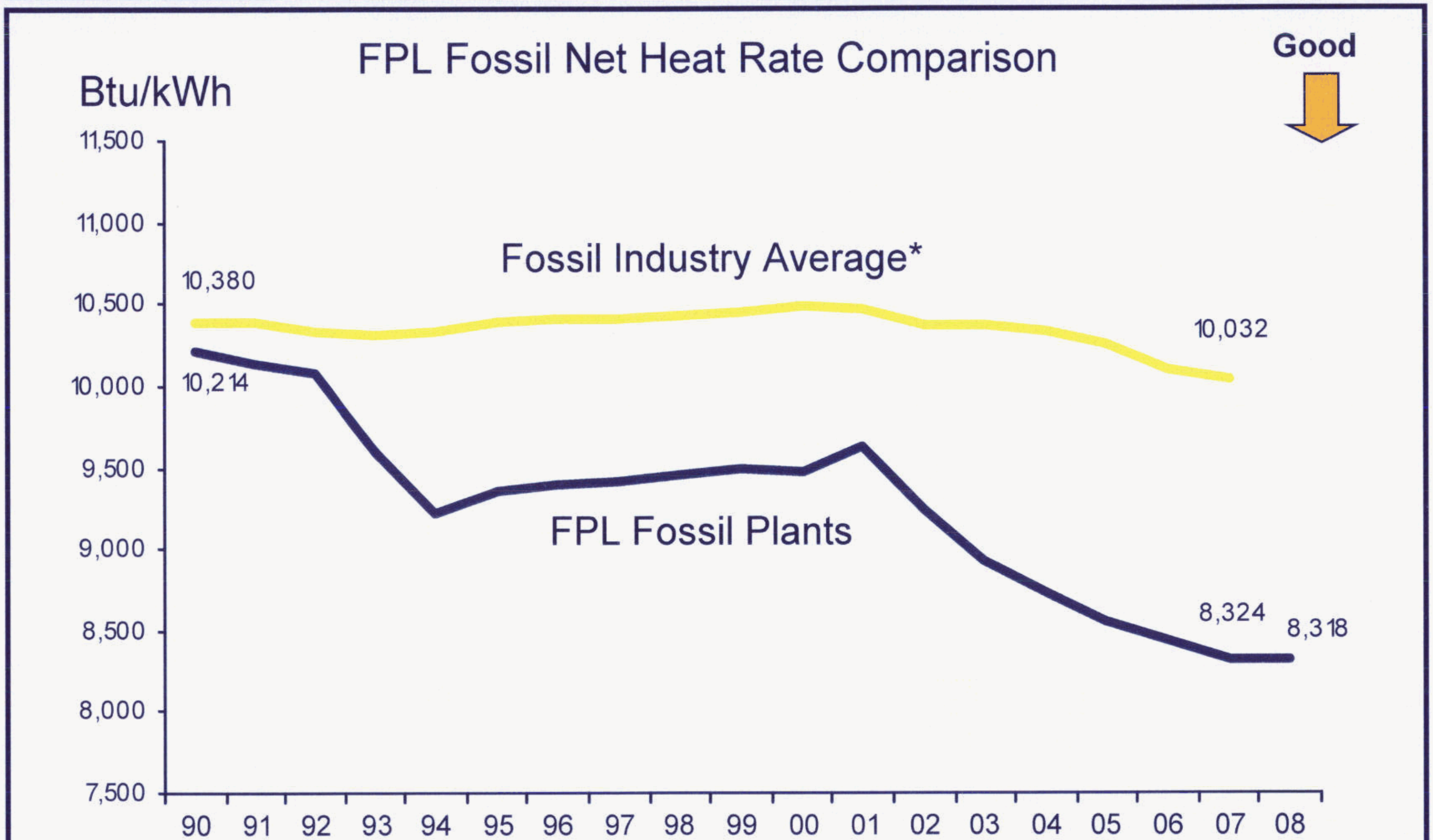
*FERC "Other" Production capacity represents combined cycle, simple cycle, and gas turbine units in FPL's fossil fleet.

FPL's investment in its fossil fleet provides customers with reliable, cost effective, cleaner and more-efficient generating capability

Docket No. 080677-EI
Changes in FPL Fossil Generating Capability
Exhibit GKH-1, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 77
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS George K. Hardy (GKH-2)
DATE 10/23/09

FPL's fossil heat rate, reflecting fuel consumption efficiency, has improved nearly 19% since 1990 and is significantly better than the fossil industry average



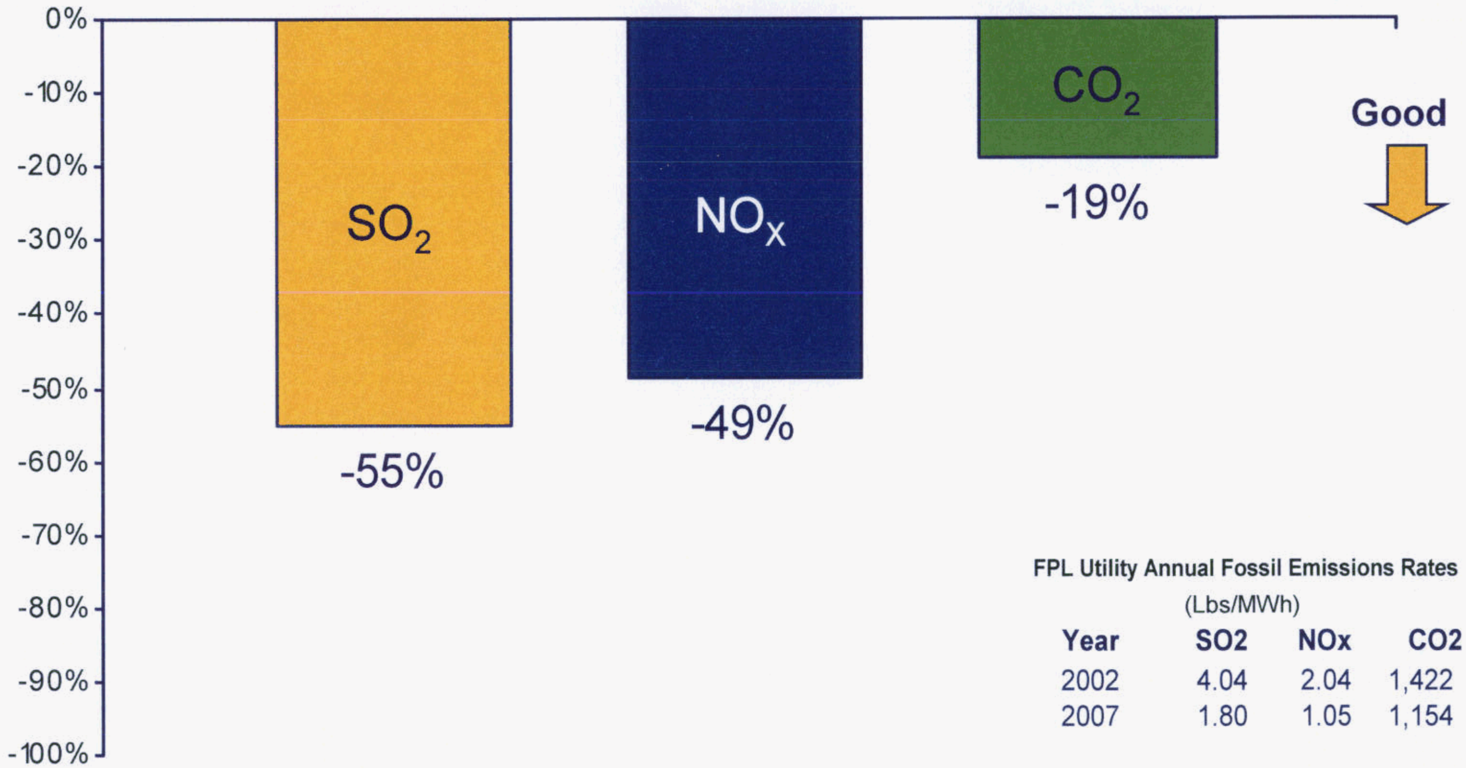
*Source: Platts - fossil plants in the U.S. Excludes FPL.

FPL's outstanding and highly efficient fossil fleet results in significantly less fuel costs and reduced emission rates

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 78
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS George K. Hardy (GKH-3)
DATE 10/23/09

FPL has significantly reduced fossil emission rates in the recent five year period through the use of cleaner, highly efficient combined cycle technology

FPL Fossil 5-Year Cumulative Percent Reduction in Emission Rates



FPL Utility Annual Fossil Emissions Rates
(Lbs/MWh)

Year	SO2	NOx	CO2
2002	4.04	2.04	1,422
2007	1.80	1.05	1,154

Source: FPL Environmental Dept. (Note: Emission rates represent FPL's capacity ownership share.)

Lowering emission rates significantly avoids pollutant and greenhouse gas releases, contributing to a cleaner environment for FPL customers

Docket No. 080677-EI
FPL Fossil 5-Year Cumulative Percent
Reduction in Emission Rates
Exhibit GKH-3, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080677-EI & 090130-EI EXHIBIT 79

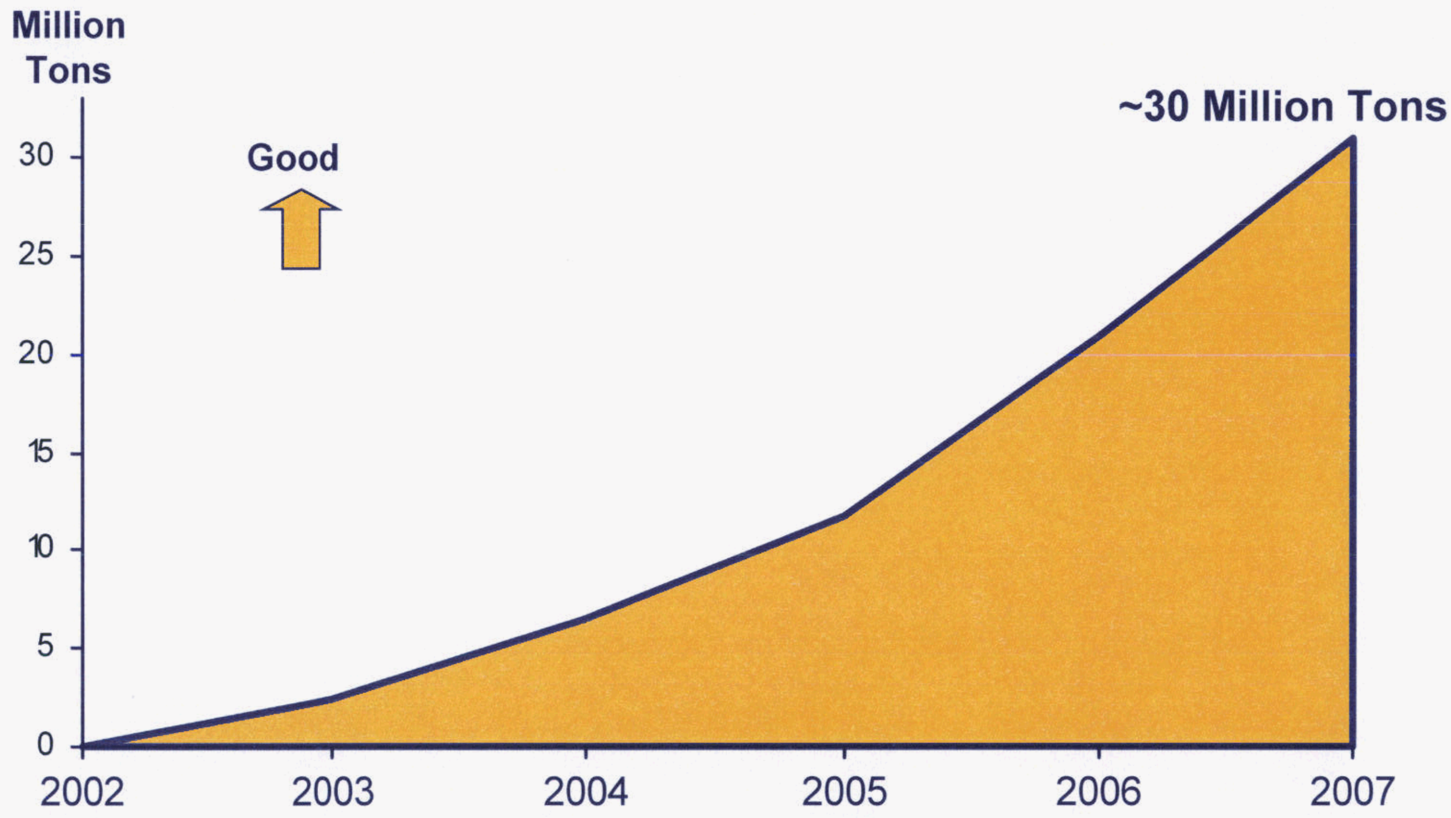
COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS George K. Hardy (GKH-4)

DATE 10/23/09

FPL reduced its fossil CO_2 emission rate almost 19% in five years through more highly efficient generation, avoiding over 30 million cumulative tons of CO_2 releases

FPL Fossil 5-Year Cumulative CO_2 Greenhouse Gas Avoided



Note: Avoided emission estimates based on emission rates supplied by FPL Environmental Dept.

Avoiding greenhouse gas emissions through energy efficiency is part of FPL's strategy for contributing to the solution of climate change

Docket No. 080677-EI
FPL Fossil 5-Year Cumulative CO_2
Greenhouse Gas Avoided
Exhibit GKH-4, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

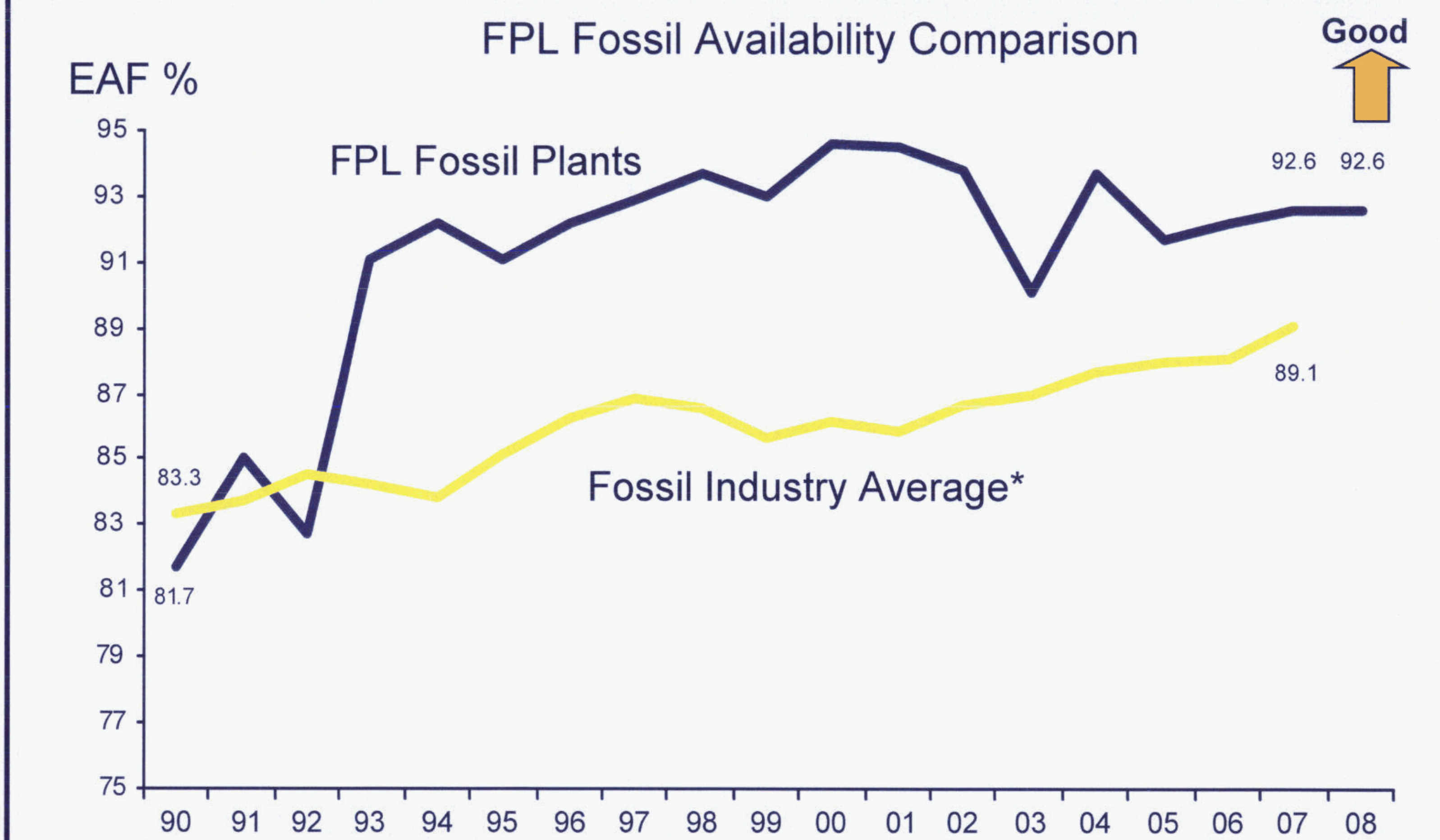
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 80

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS George K. Hardy (GKH-5)

DATE 10/23/09

FPL has improved its fossil fleet availability to over 92% and has performed significantly above the fossil industry average



*Source: North American Electric Reliability Corporation (NERC). Weighted EAF (Equivalent Availability Factor - excluding Maintenance Outage Factor) for fossil steam and combined cycle units for all reporting companies. Excludes FPL.

FPL's excellent fossil availability results in more opportunity for highly efficient capacity to be operating, minimizing customer fuel costs and emissions

Docket No. 080677-EI
FPL Fossil Availability Comparison
Exhibit GKH-5, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

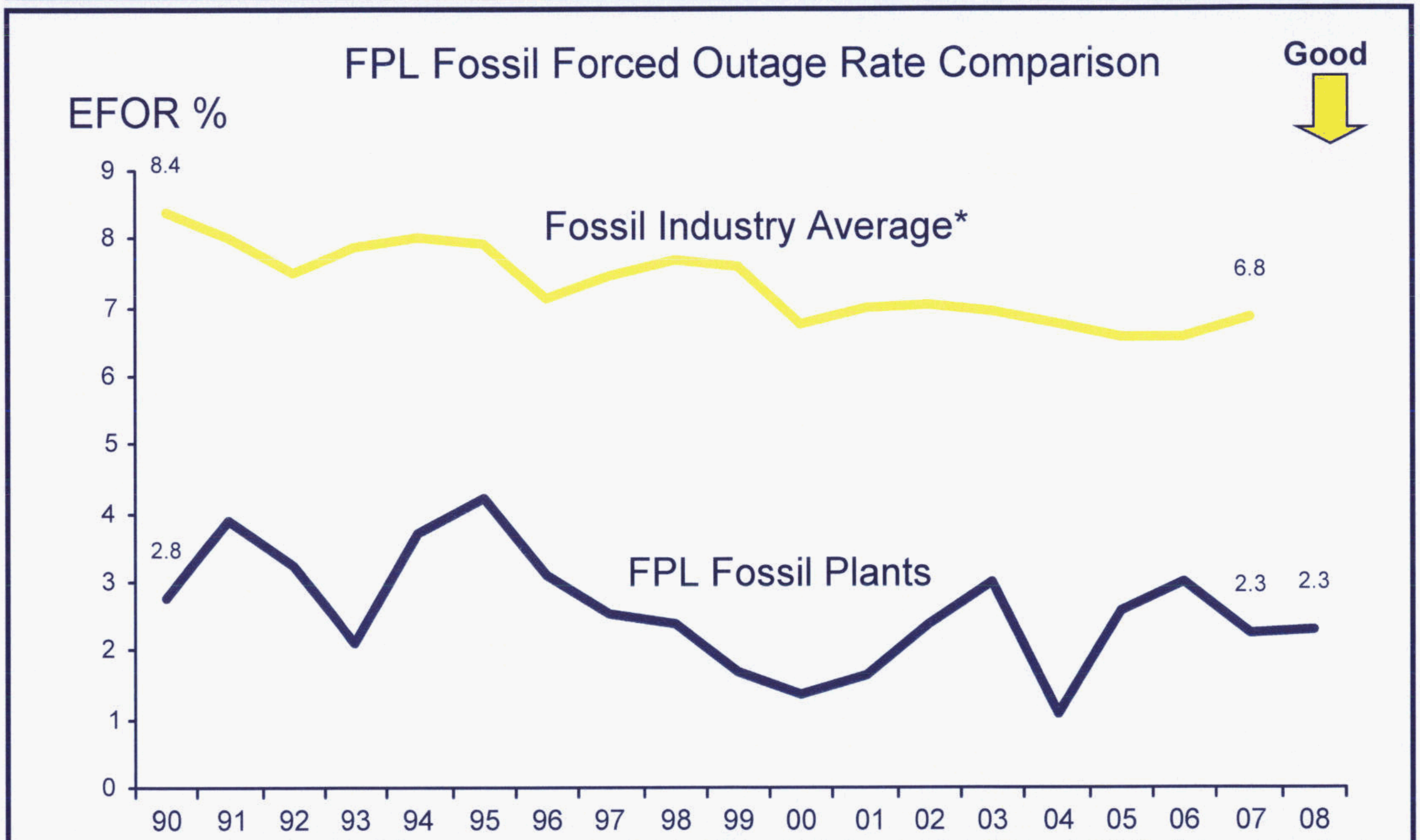
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 81

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS George K. Hardy (GKH-6)

DATE 10/23/09

FPL's fossil fleet's excellent Equivalent Forced Outage Rate averaging 2% during the last ten years is less than one third the fossil industry average failure rate



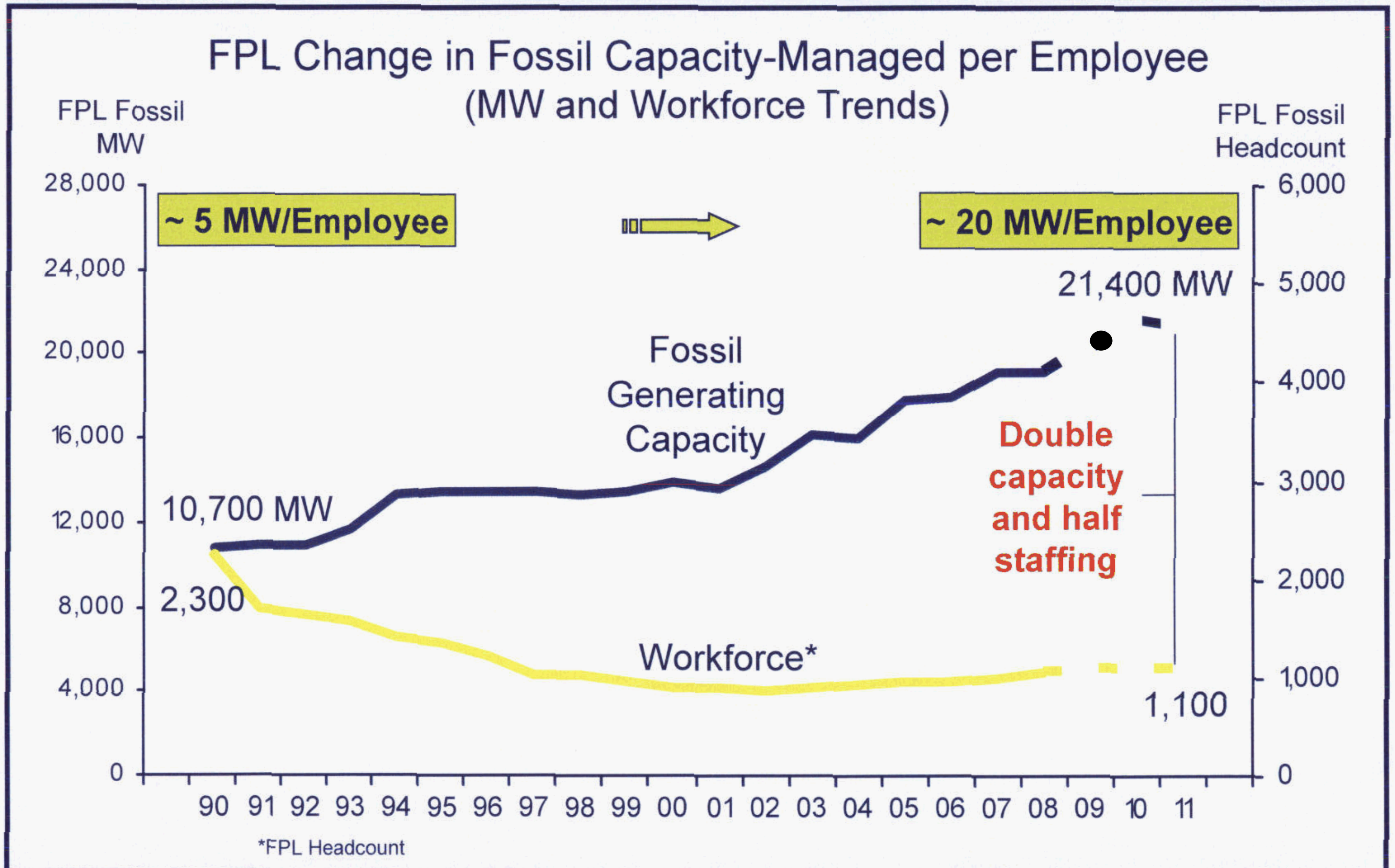
*Source: North American Electric Reliability Corporation (NERC). Weighted EFOR (Equivalent Forced Outage Rate) for fossil steam and combined cycle units for all reporting companies. Excludes FPL.

FPL's low fossil fleet EFOR represents better reliability (i.e. less failure), resulting in greater availability of the most-efficient generating capacity serving customers

Docket No. 080677-EI
FPL Fossil Forced Outage Rate Comparison
Exhibit GKH-6, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 82
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS George K. Hardy (GKH-7)
DATE 10/23/09

By 2011, FPL's fossil capacity-managed per employee is projected to be four times higher than the rate achieved in 1990 – from about 5 MW/employee to about 20 MW/employee

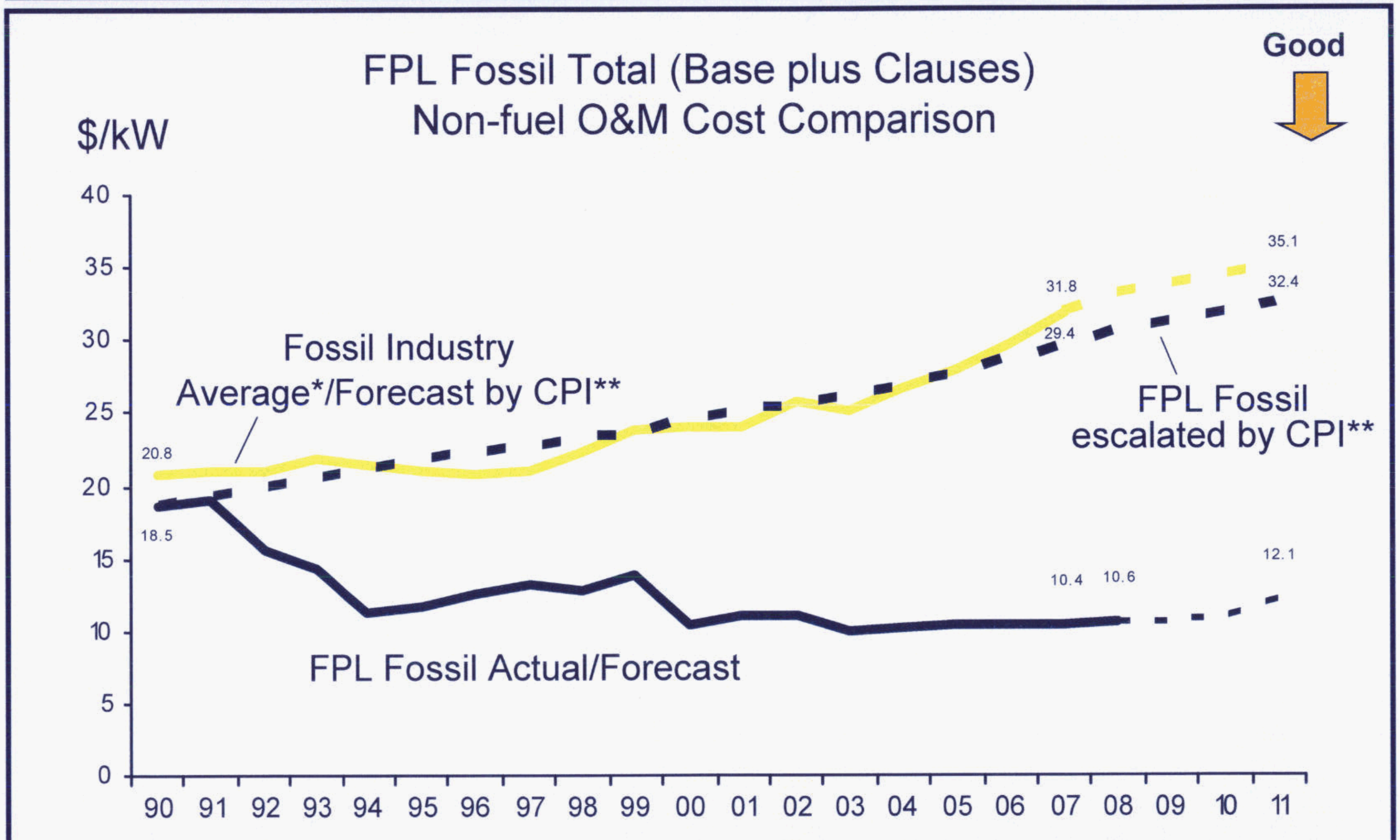


Improving generating capacity management results in lower non-fuel O&M cost to FPL customers

Docket No. 080677-EI
FPL Change in Fossil Capacity-Managed per Employee
Exhibit GKH-7, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 83
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS George K. Hardy (GKH-8)
DATE 10/23/09

FPL's fossil fleet total non-fuel O&M cost per kW of capacity was reduced over 40% since 1990, and is well below both the corresponding CPI and fossil industry trends



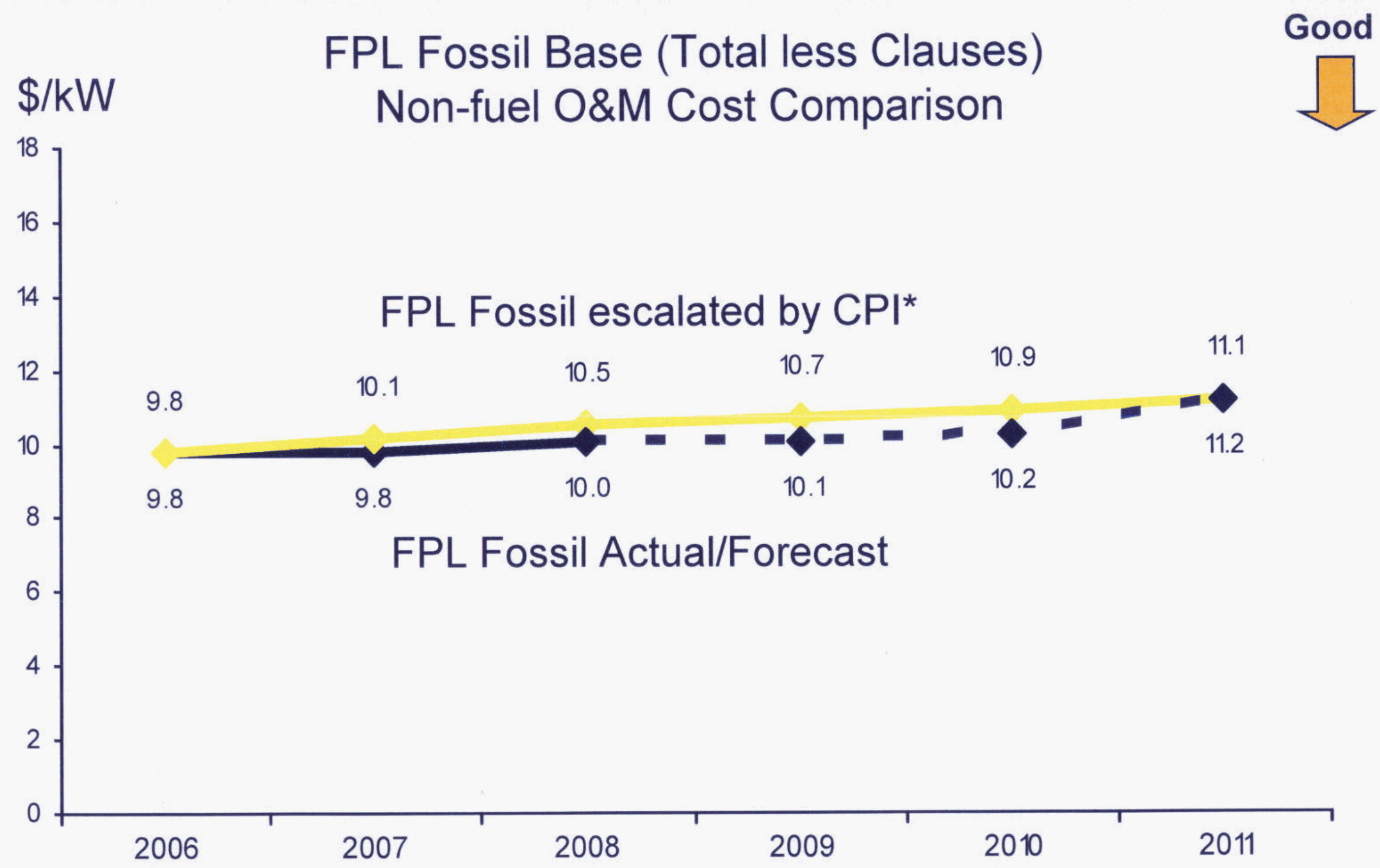
*Source: Platts - FERC Form 1 Steam plus Other cost. (Capacity based on summer capability). Excludes FPL. **CPI used for calculating FPSC's FPL O&M Benchmark

FPL's exemplary non-fuel O&M performance associated with the economies-of-scale of its modernized fossil fleet has avoided significant cost to FPL customers

Docket No. 080677-EI
FPL Fossil Total Non-Fuel
O&M Cost Comparison
Exhibit GKH-8, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 84
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS George K. Hardy (GKH-9)
DATE 10/23/09

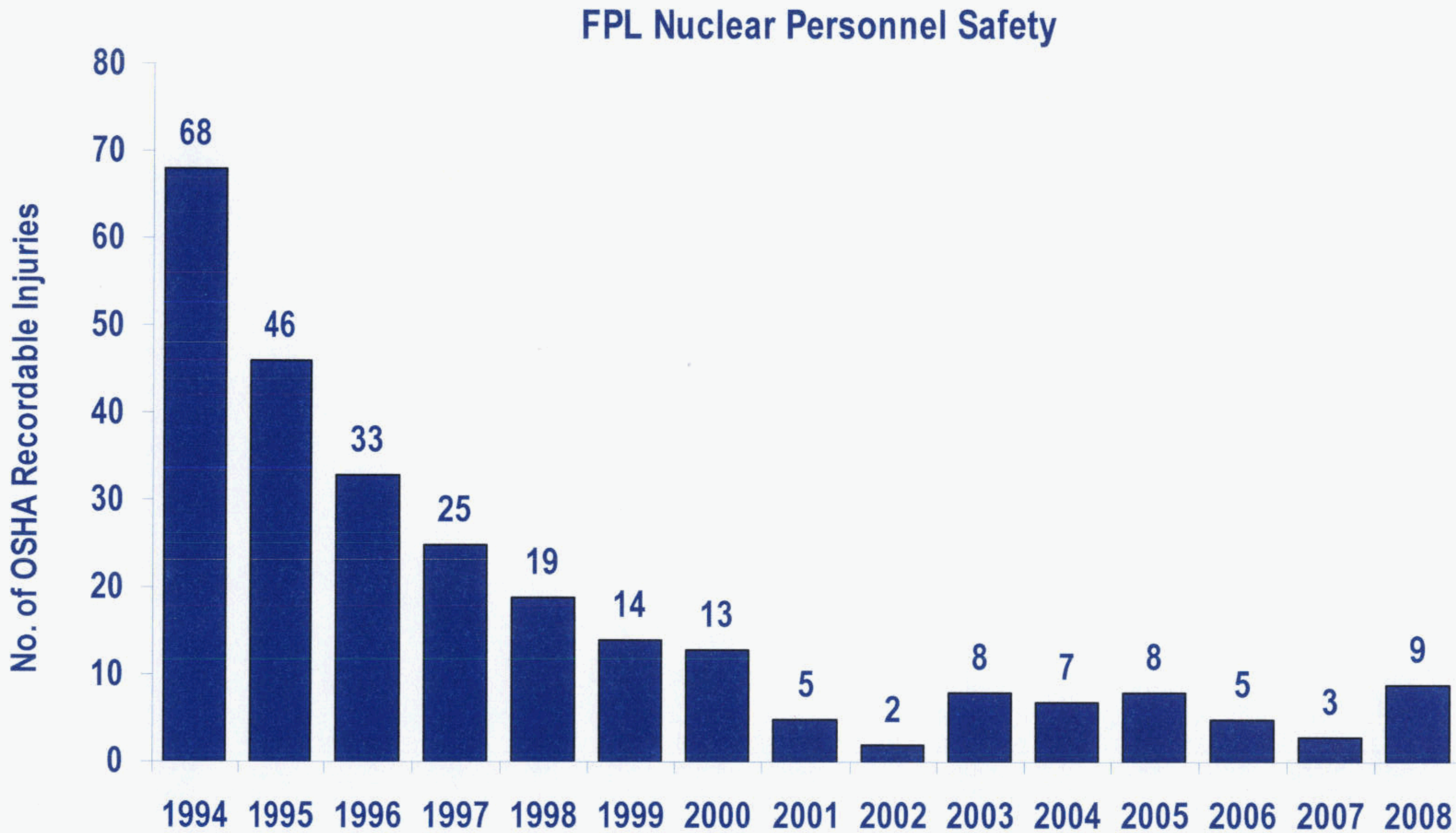
FPL's fossil "Steam" plus "Other" base non-fuel O&M cost per kW of capacity is projected to be consistent with CPI inflation throughout the 2006-2011 timeframe



*CPI used for calculating FPSC's FPL O&M Benchmark. FPL's 2006 - 2011 fossil O&M cost per kW includes 4,800 MW of new combined cycle capacity.

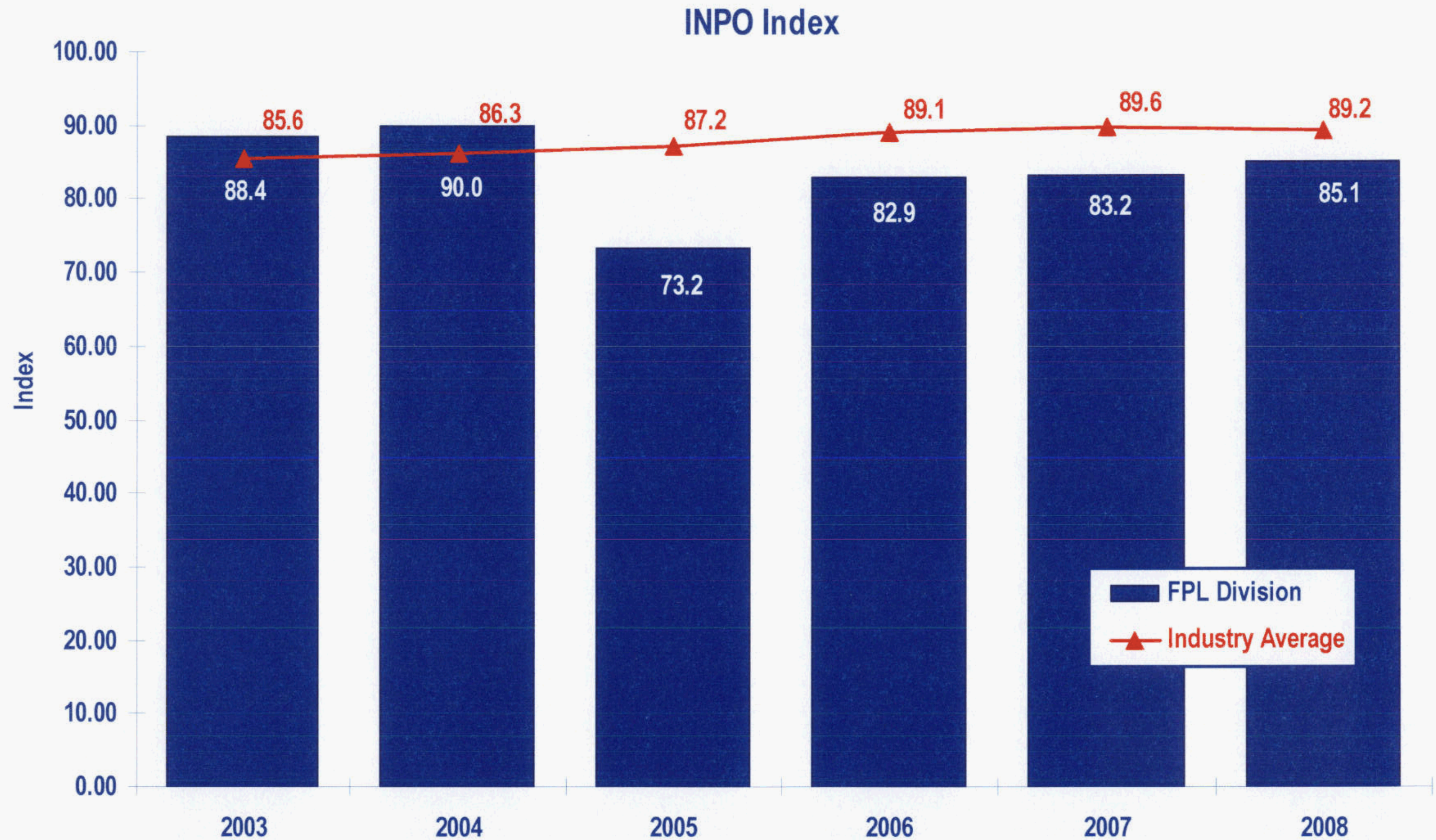
FPL's fossil base O&M cost per kW against CPI (which does not consider 4,800 MW of new capacity between 2006 and 2011) reflects FPL's excellent cost management performance

Docket No. 080677-EI
FPL Fossil Base Non-Fuel
O&M Cost Comparison
Exhibit GKH-9, Page 1 of 1



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 85
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS J. A. Stall (JAS-1)
DATE 09/03/09

Docket No. 080677-EI
FPL Nuclear Personnel Safety
Exhibit No. JAS-1, Page 1 of 1



2005 INPO Index affected by planned work to address industry-wide issues; INPO Index gradually increased since 2005

Data source: Institute of Nuclear Power (INPO)
2008 Industry average data: 3rd Quarter 2008

Docket No. 080677-EI
INPO Index
Exhibit No. JAS-2, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 86
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS J. A. Stall (JAS-2)
DATE 09/03/09

Docket No. 080677-EI
NRC Performance Indicators for
St. Lucie and Turkey Point
Exhibit No. JAS-3, Page 1 of 1

As of December 31, 2008

NRC Performance Indicators for St. Lucie and Turkey Point

	Turkey Point Unit 3	Turkey Point Unit 4	St. Lucie Unit 1	St. Lucie Unit 2
Initiating Events Cornerstone				
Unplanned Reactor Scrams per 7000 Critical Hours (Automatic and Manual)	Green	Green	Green	Green
Unplanned Reactor Scrams with Loss of Normal Heat Removal	Green	Green	Green	Green
Unplanned Scrams with Complications	Green	Green	Green	Green
Mitigating Systems Cornerstone				
Mitigating System Performance	Green	Green	Green	Green
Safety System Functional Failures	Green	Green	Green	Green
Barriers Cornerstone				
RCS Activity	Green	Green	Green	Green
RCS Leakage	Green	Green	Green	Green
Emergency Preparedness Cornerstone				
Emergency Response Organization (ERO) Drill/Exercise Performance	Green	Green	Green	Green
ERO Drill Participation	Green	Green	Green	Green
Alert and Notification System Performance	Green	Green	Green	Green
Occupational Radiation Safety Cornerstone				
Occupational Exposure Control Effectiveness	Green	Green	Green	Green
Public Radiation Safety Cornerstone				
RETS/ODCM Radiological Effluent Occurrence	Green	Green	Green	Green
Physical Protection Cornerstone				
Protected Area Security Equipment Performance Index	Green	Green	Green	Green

Acceptable Performance Licensee Response Band	Green
Acceptable Performance Increased Regulatory Response Band	White
Acceptable Performance Required Regulatory Response Band	Yellow
Unacceptable Performance Plants not normally permitted to operate within this band	Red

Data source: U.S. Nuclear Regulatory Commission

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 87
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS J. A. Stall (JAS-3)
DATE 09/03/09

Docket No. 080677-EI
NRC Inspection Findings for St. Lucie and Turkey Point for 2008
Exhibit No. JAS-4, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET No. 080677-EI & 090130-EI EXHIBIT 88
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS J. A. Stall (JAS-4)
DATE 08/26/09

As of December 31, 2008

NRC Inspection Findings for St. Lucie and Turkey Point

	Turkey Point Unit 3	Turkey Point Unit 4	St. Lucie Unit 1	St. Lucie Unit 2
Initiating Events	Green	Green	Green	Green
Mitigating Systems	Green	Green	Green	Green
Barriers	Green	Green	Green	Green
Emergency Preparedness	Green	Green	Green	Green
Occupational Radiation Safety	Green	Green	Green	Green
Public Radiation Safety	Green	Green	Green	Green
Physical Protection	Green	Green	Green	Green

Data source: U.S. Nuclear Regulatory Commission

As of December 31, 2008

NRC Regulatory Status for St. Lucie and Turkey Point

Turkey Point Unit 3	Turkey Point Unit 4	St. Lucie Unit 1	St. Lucie Unit 2
Column 1 Licensee Response	Column 1 Licensee Response	Column 1 Licensee Response	Column 1 Licensee Response

Best

Column 1 – Licensee Response
Column 2 – Regulatory Response
Column 3 – Degraded Cornerstone
Column 4 – Multiple/Repetitive Cornerstones
Column 5 – Unacceptable Performance

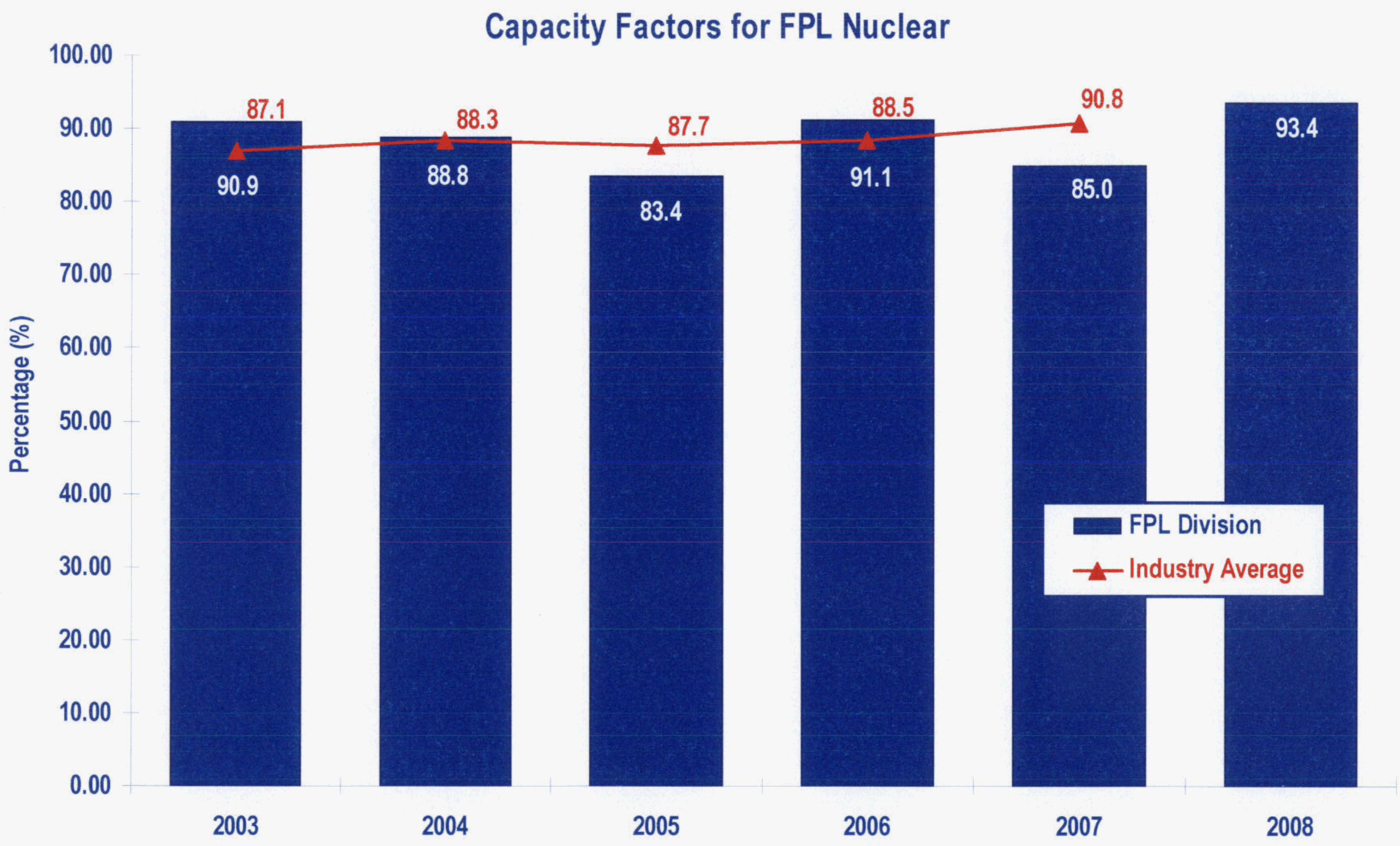
Worst

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 89
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS J. A. Stall (JAS-5)
DATE 08/26/09

Data source: U.S. Nuclear Regulatory Commission

Docket No. 080677-EI
NRC Regulatory Status for St. Lucie and Turkey Point
Exhibit No. JAS-5, Page 1 of 1

Docket No. 080677-EI
Capacity Factors for FPL Nuclear
Exhibit No. JAS-6, Page 1 of 1

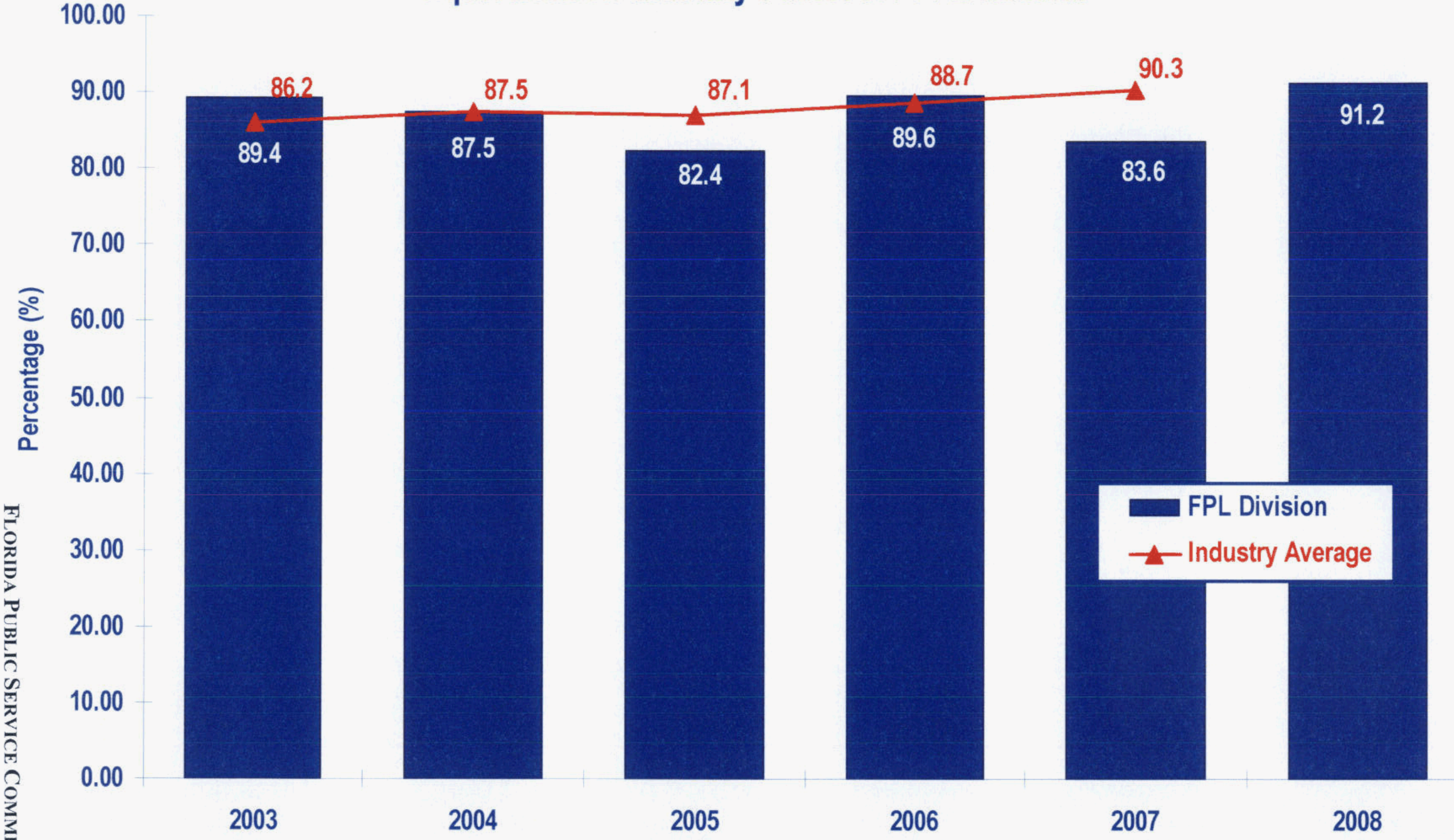


2005 and 2007 affected by planned work to address industry-wide issues

Data source: North American Electric Reliability Council – Generating Availability Data System (NERC-GADS)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 90
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS J. A. Stall (JAS-6)
DATE 08/26/09

Equivalent Availability Factor for FPL Nuclear



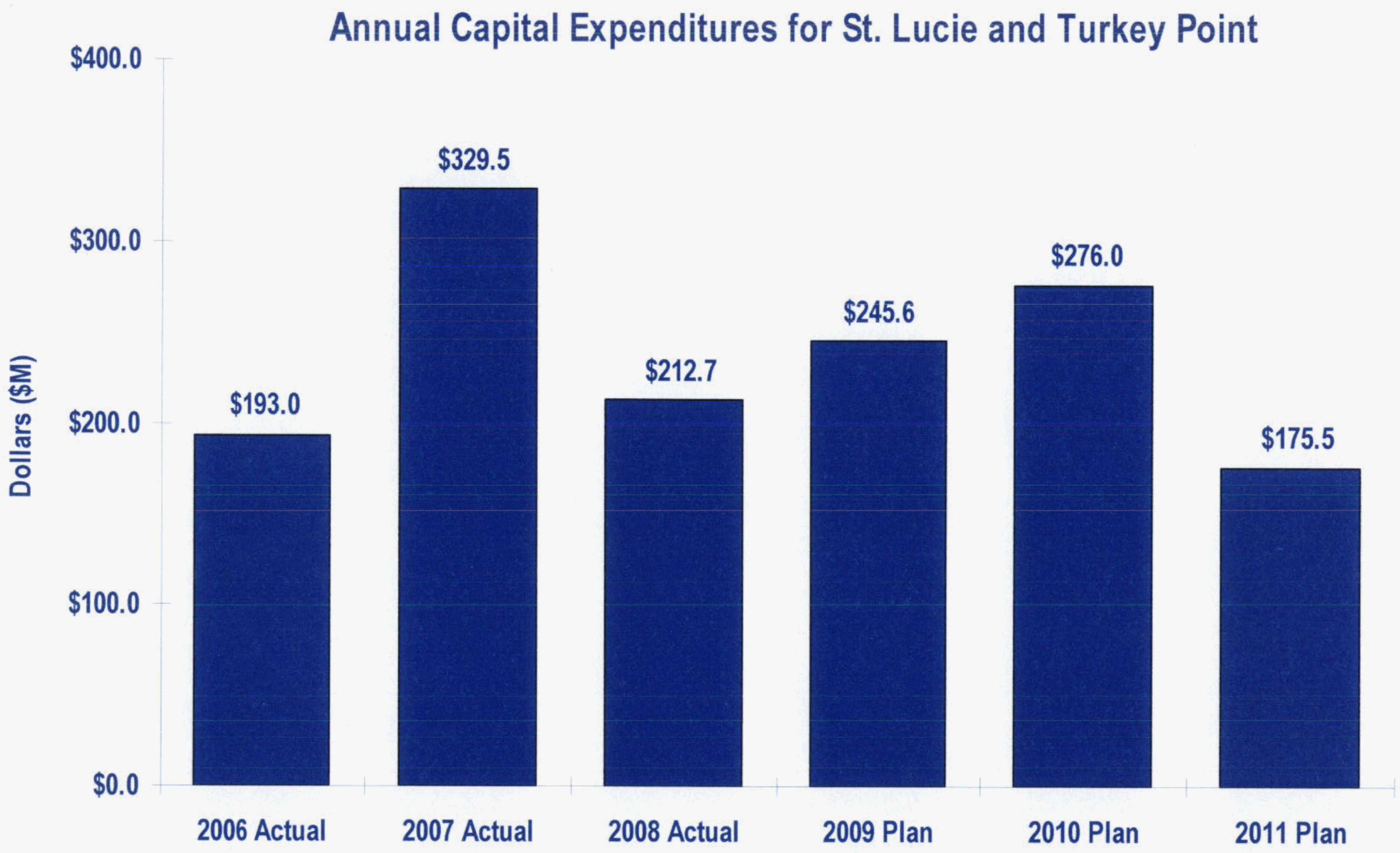
2005 and 2007 affected by planned work to address industry-wide issues

Data source: North American Electric Reliability Council – Generating Availability Data System (NERC-GADS)

Docket No. 080677-EI
Equivalent Availability Factor for FPL Nuclear
Exhibit No. JAS-7, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 91
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS J. A. Stall (JAS-7)
DATE 08/26/09

Docket No. 080677-EI
Annual Capital Expenditures for
St. Lucie and Turkey Point
Exhibit No. JAS-8, Page 1 of 1



FPL's annual capital expenditures for St. Lucie and Turkey Point above do not include capital expenditures for the uprates.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 92
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS J. A. Stall (JAS-8)
DATE 08/26/09

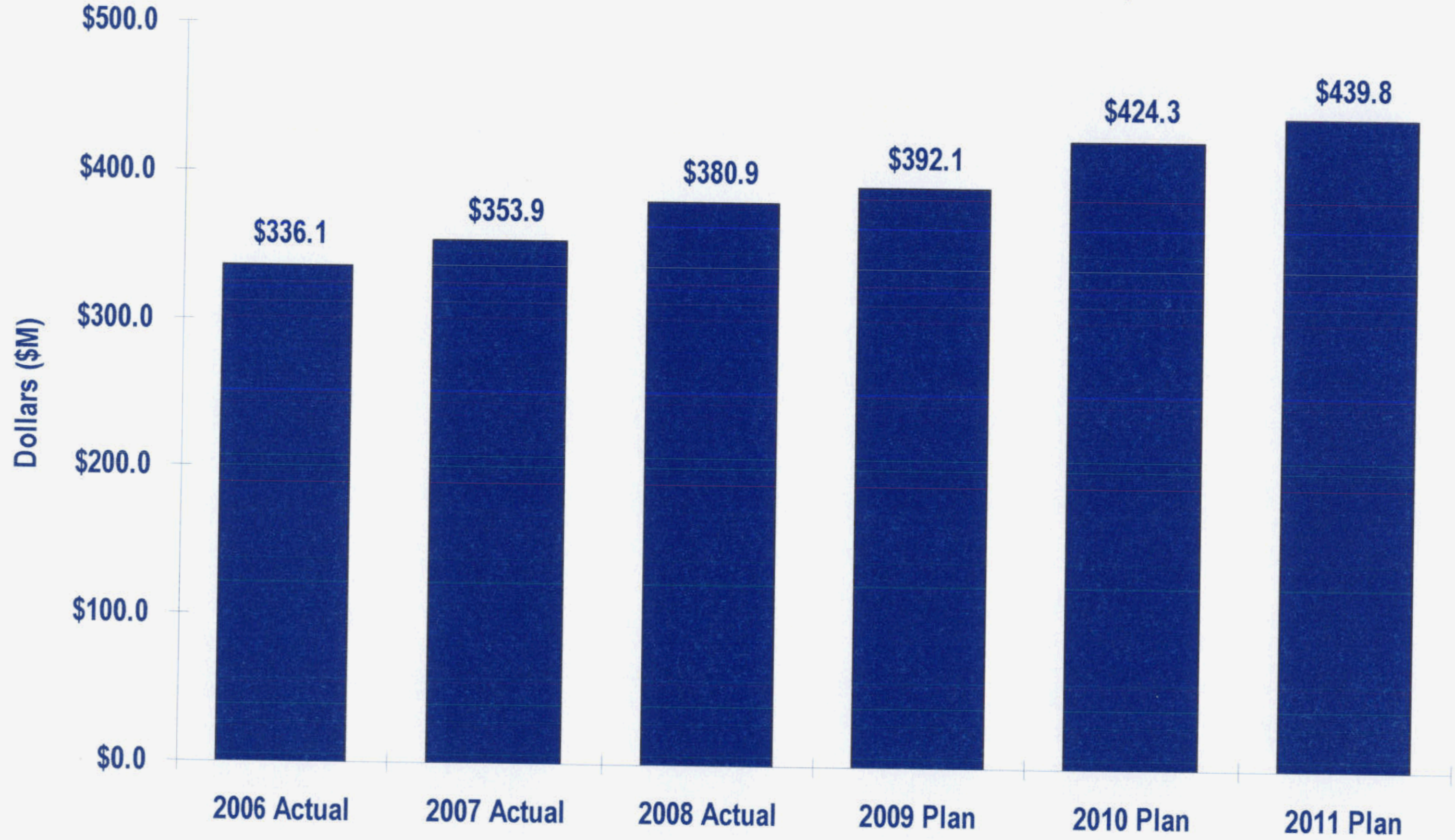
Docket No. 080677-EI
Cumulative Capital Investment
2006-2011
Exhibit No. JAS-9, Page 1 of 1

Cumulative Capital Investment 2006 - 2011

Project	2006	2007	2008	2009	2010	2011	Total
Turkey Point Excellence Program		1,308,179	47,874,142	65,087,180	70,408,201	35,306,780	219,984,482
St. Lucie Unit 2 Steam Generator Replacement	44,113,721	107,505,276	15,970,315	3,120,000	-	-	170,709,312
Turkey Point & St. Lucie Spent Fuel Management	25,946,552	28,476,585	18,704,700	35,024,625	27,431,396	7,459,408	143,043,265
Control Room Digitial Upgrade Project	19,315,293	20,930,696	16,717,352	12,667,753	17,200,075	7,341,294	94,172,464
Turkey Point Equipment Reliability	17,338,900	13,200,911	11,472,155	8,530,000	13,900,000	17,300,000	81,741,966
St. Lucie Equipment Reliability	14,442,392	13,179,050	8,665,888	13,760,754	13,400,000	16,800,000	80,248,084
Alloy 600 Mitigation Projects	394,887	9,958,450	7,895,478	7,411,615	45,808,599	761,040	72,230,069
Containment Sumps	6,749,298	38,580,986	14,042,528	-	-	-	59,372,812
St. Lucie Reactor Head Replacement	14,448,928	36,111,562	3,145,065	-	-	-	53,705,554
St. Lucie License Renewal		911,074	15,998,759	11,948,682	9,808,686	9,808,686	48,475,887
Turkey Point Projects & Turbine Generator	18,863,263	(1,961,032)	6,074,355	12,212,119	6,375,212	7,645,340	49,209,257
St. Lucie Minor Projects	5,363,728	5,360,237	(1,094,159)	4,850,970	7,267,853	18,882,848	40,631,477
St. Lucie ICI Thimble Replacements	1,702,192	18,656,894	(3,869)	500,000	16,166,598	-	37,021,815
St. Lucie RCP Motor Swaps		350,596	7,560,047	3,623,998	12,507,001	9,360,000	33,401,642
Turkey Point Unit 3 Turbine Generator	-	10,037,981	574,750	9,517,571	3,859,096	674,814	24,664,212
NFPA 805 Fire Protections			-	-	-	24,747,407	24,747,407
Turkey Point Unit 4 Turbine Generator	3,670,718	788,789	5,563,152	6,701,524	658,546	3,422,324	20,805,053
St. Lucie Maintenance Bldg			6,870,597	13,102,349	-	-	19,972,946
St. Lucie Unit 2 Turbine Generator	4,900,134	2,055,426	751,912	6,662,080	4,607,330	985,243	19,962,125
St. Lucie Unit 2 Pressurizer Heater Sleeve Repair			109,776	3,239,997	12,700,000	-	16,049,773
Generic Letter 2008-01 Gas Accumulation Project			7,728,663	7,600,000	-	-	15,328,663
St. Lucie Unit 1 Turbine Generator	111,228	2,742,636	3,076,221	935,135	4,496,262	3,787,128	15,148,609
Turkey Point Split Pin Replacements	2,348,151	6,278,921	5,158,072	-	-	-	13,785,144
Sub-Total	179,709,385	314,473,215	202,855,899	226,496,352	266,594,855	164,282,312	1,354,412,018
St. Lucie / Turkey Point Base Projects	13,247,847	14,990,143	9,809,939	19,093,647	9,453,144	11,197,687	79,623,781
Total	**192,957,232**	**329,463,359**	**212,665,838**	**245,589,999**	**276,047,999**	**175,479,999**	**1,434,035,799**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 93
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS J. A. Stall (JAS-9)
DATE 08/26/09

Annual O&M Expenditures for St. Lucie and Turkey Point



Docket No. 080677-EI
Annual O&M Expenditures for
St. Lucie and Turkey Point
Exhibit No. JAS-10, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 94
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS J. A. Stall (JAS-10)
DATE 08/26/09

Distribution Reliability Program Initiatives*

[illegible]	[illegible]
Hardening Plan **	Approved 3-prong plan strengthens the distribution infrastructure
Pole Inspections **	Approved plan implements 8 year inspection cycle
Vegetation Management **	Approved 3-year average cycle (feeders) and 6-year average cycle (laterals) minimizes vegetation related interruptions
System Expansion	Provides necessary feeder capacity to serve all customers during normal and emergency periods, and installs necessary infrastructure to meet new loads
Priority Feeders & Laterals	Identification/remediation of feeders/laterals experiencing the most interruptions and momentaries
Overhead Line Inspections	Infrared predictive diagnostic technology detects signs of failures, or potential failures, in overhead facilities; coupled with a visual condition assessment
Feeder/Lateral Cable	Reduces direct buried feeder/lateral cable failures and associated interruptions
Submarine Cable	Reduces submersible feeder cable failures and associated interruptions
VAR Management	Maintains/improves power factor performance, improves system efficiency, reliability, and quality of service voltage
Automated Feeder Switching	Maintains switches that automatically sectionalize lines, isolates faults, and restores customers
Customer Impact	Projects that target improvements for specific customers or geographic areas
Vault Inspections	Inspection/remediation of non-compliant conditions in automatic throw-over systems and other vault equipment
Pad-mounted Security and Inspections	Inspection/remediation of non-compliant conditions
Switch Cabinets	Removal of live front switch cabinets which are reaching end of life
Handhole Inspections	Inspection/remediation of non-compliant conditions

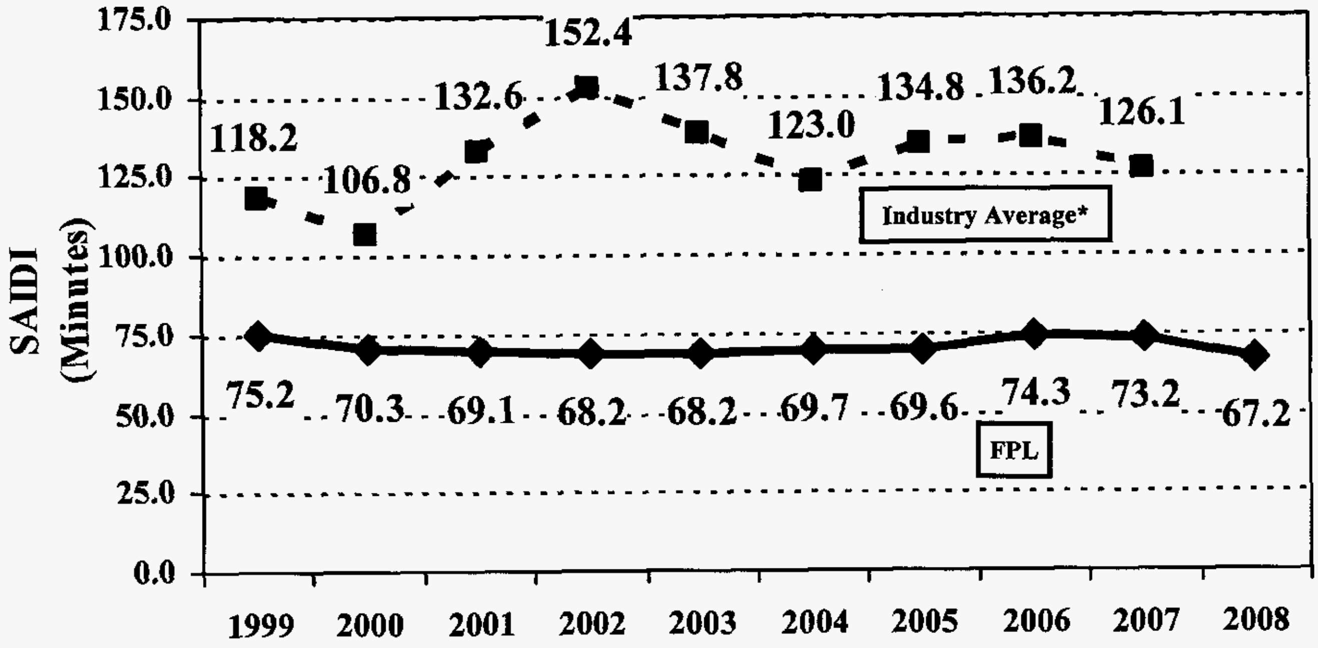
* Reliability program initiatives with annual costs > $1 million

** Can also be referred to as a "Hardening" and/or "Storm Preparedness" Initiative

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 95
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Michael G.Spoor (MGS-1)
DATE 08/31/09

Docket No. 080677-EI
Distribution Reliability Results
Exhibit MGS-2, Page 1 of 1

Distribution Reliability Results



* Industry Average data from EEI (2008 not available until late 2009)

FPL Distribution SAIDI 45% Better Than Industry Average

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 96
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Michael G.Spoor (MGS-2)
DATE 08/31/09

Docket No. 080677-EI
Distribution Costs by Cost Category 2006-2011
Exhibit MGS-3, Page 1 of 1

DISTRIBUTION COSTS 2006 - 2011
($MILLIONS)

ACTUAL 2006-2008 COST CATEGORY	2006 O & M	2007 O & M	2008 O & M	TOTAL 2006-2008 O & M	AVERAGE 2006-2008 O & M	2006 CAPITAL	2007 CAPITAL	2008 CAPITAL	TOTAL 2006-2008 CAPITAL	AVERAGE 2006-2008 CAPITAL
GROWTH	26.1	16.7	11.9	54.7	18.2	364.1	301.6	176.8	842.5	280.8
RELIABILITY	57.8	58.4	58.2	174.4	58.1	78.4	76.6	71.1	226.1	75.4
HARDENING	20.3	36.6	29.4	86.3	28.8	26.8	51.2	77.2	155.2	51.7
RESTORATION	80.3	79.3	78.0	237.6	79.2	63.6	66.9	74.6	205.1	68.4
CUSTOMER RESPONSE	24.4	21.4	25.4	71.2	23.7	48.0	38.1	26.3	112.4	37.5
FIELD SUPPORT	27.2	34.3	30.2	91.7	30.6	2.4	16.4	14.4	33.2	11.1
DISTRIBUTION BU COSTS	236.1	246.7	233.1	715.9	**238.6**	583.3	550.8	440.4	1574.5	**524.8**
OTHER *	52.1	28.8	35.6	116.5	38.9					
DISTRIBUTION FERC	288.2	275.5	268.7	832.4	**277.5**					

FORECAST 2009-2011 COST CATEGORY	2009 O & M	2010 O & M	2011 O & M	TOTAL 2009-2011 O & M	AVERAGE 2009-2011 O & M	2009 CAPITAL	2010 CAPITAL	2011 CAPITAL	TOTAL 2009-2011 CAPITAL	AVERAGE 2009-2011 CAPITAL
GROWTH	4.0	9.1	11.4	24.5	8.2	88.5	167.4	192.4	448.3	149.4
RELIABILITY	66.7	67.3	73.1	207.1	69.0	54.9	66.7	75.6	197.2	65.7
HARDENING	35.2	41.8	42.3	119.3	39.8	112.2	144.6	148.3	405.1	135.0
RESTORATION	62.7	63.9	69.6	196.2	65.4	53.8	61.0	69.8	184.6	61.5
CUSTOMER RESPONSE	27.4	28.0	30.5	85.9	28.6	29.7	30.3	30.9	90.9	30.3
FIELD SUPPORT	32.7	28.0	27.8	88.5	29.5	5.5	21.0	21.0	47.5	15.8
DISTRIBUTION BU COSTS	228.7	238.1	254.7	721.5	**240.5**	344.6	491.0	538.0	1373.6	**457.9**
OTHER *	36.7	38.4	41.6	116.7	38.9					
DISTRIBUTION FERC	265.4	276.5	296.3	838.2	**279.4**					

* Includes O&M expenses incurred or associated with other FPL business units that relate to operation and maintenance of the distribution system (as defined by FERC). Examples include Transmission and Customer Service business unit O&M expenses associated with distribution substations and meters, respectively. Not applicable for capital since FERC functional amounts are reported at a plant balance level.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 97
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Michael G.Spoor (MGS-3)
DATE 08/31/09

FLORIDA PUBLIC SERVICE COMMISSION

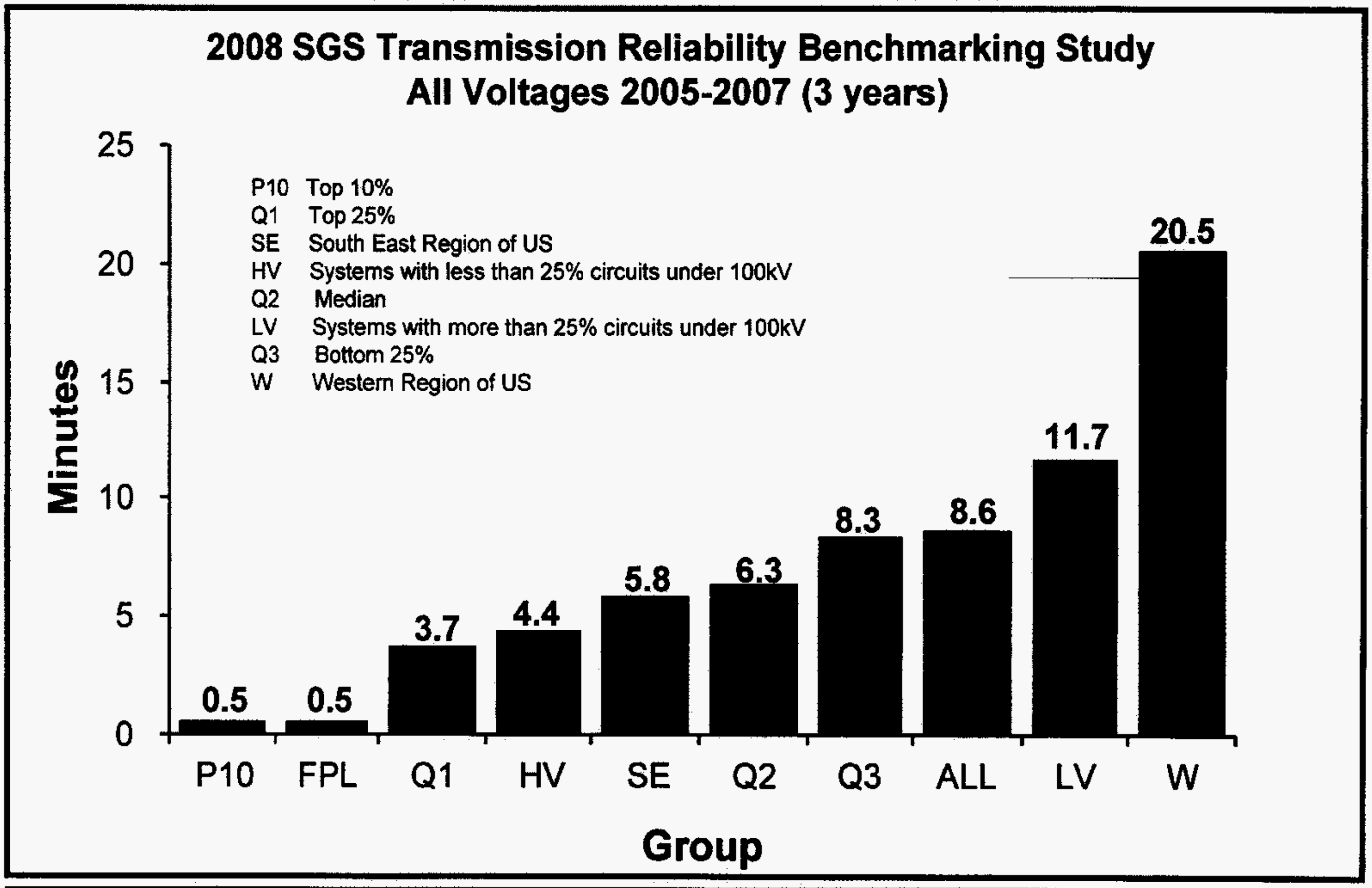
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 98

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS James A. Keener (JAK-1)

DATE 09/02/09

The FPL Transmission SAIDI compares favorably in recent industry benchmarking studies.



For industry comparisons, SAIDI is calculated for outages greater than or equal to five minutes versus FPSC definition of SAIDI of greater than or equal to one minute.

Docket No. 080677-EI
2008 SGS Transmission Reliability
Benchmarking Study All Voltages
2005-2007 (3 years)
Exhibit JAK-1 Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

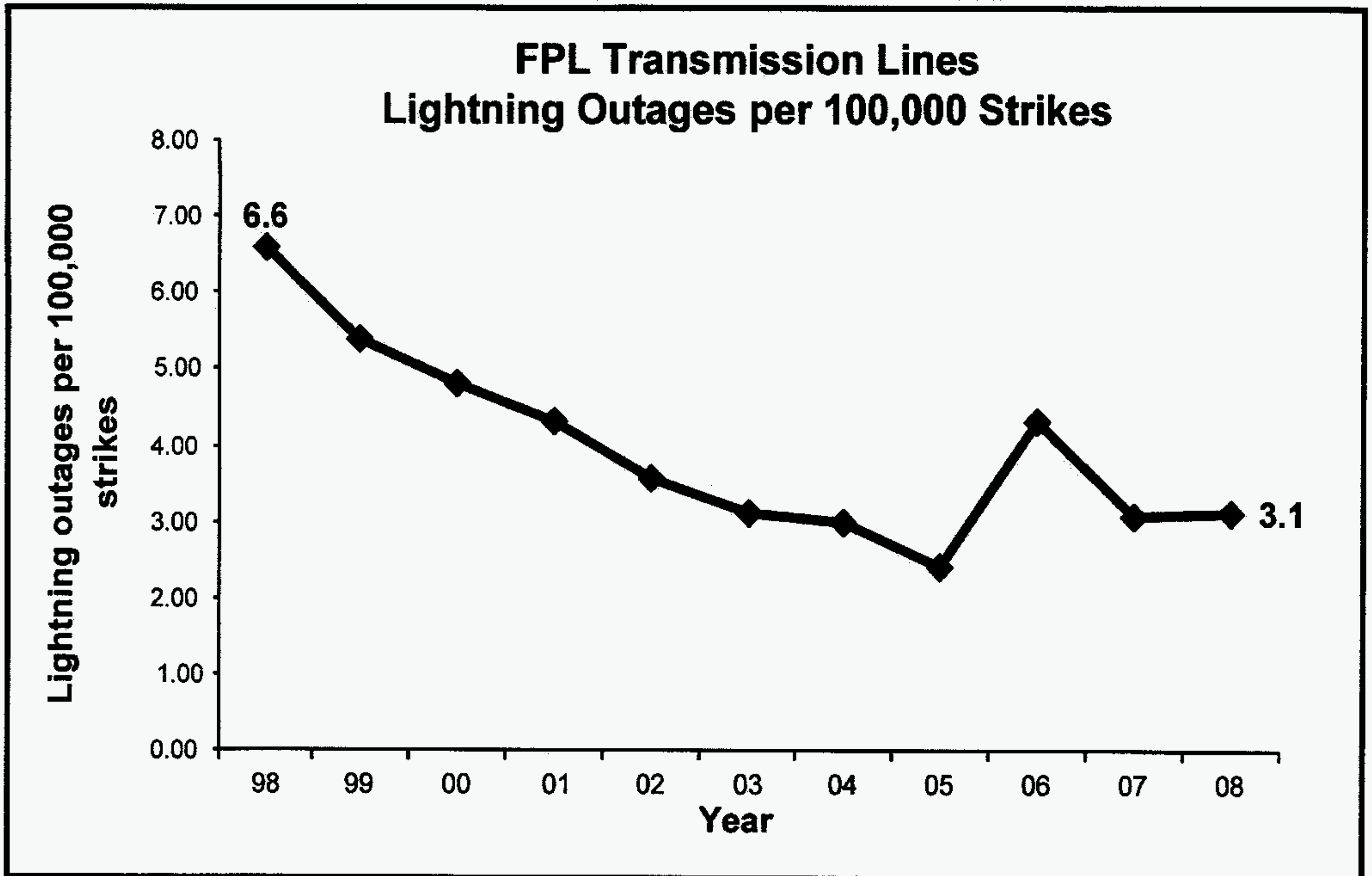
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 99

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS James A. Keener (JAK-2)

DATE 09/02/09

FPL has reduced the number of lightning outages by over 45 percent in the 1998-2008 period.

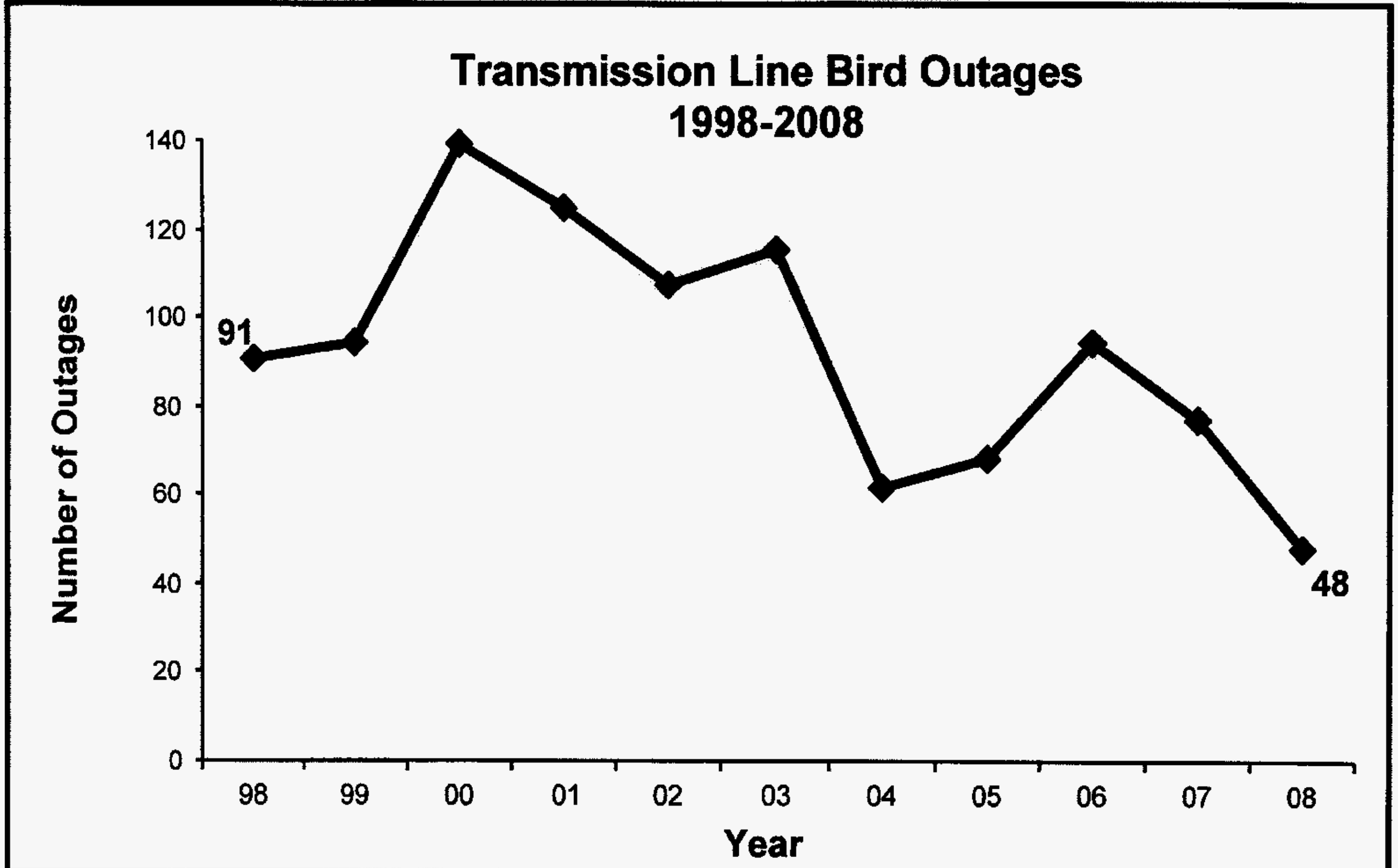


FPL's high performance demonstrates the effectiveness of the new design standards and countermeasures deployed.

Docket No. 080677-E1
FPL Transmission Lines
Lightning Outages Per
100,000 Strikes
Exhibit JAK-2 page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 100
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS James A. Keener (JAK-3)
DATE 09/02/09

FPL's reliability program has contributed to a 47 percent reduction in the number of outages related to birds in the 1998-2008 period.



Mitigation projects and rebuilding of lines with new structures designed to deter bird perching has helped to minimize the number of outages related to birds.

FLORIDA PUBLIC SERVICE COMMISSION

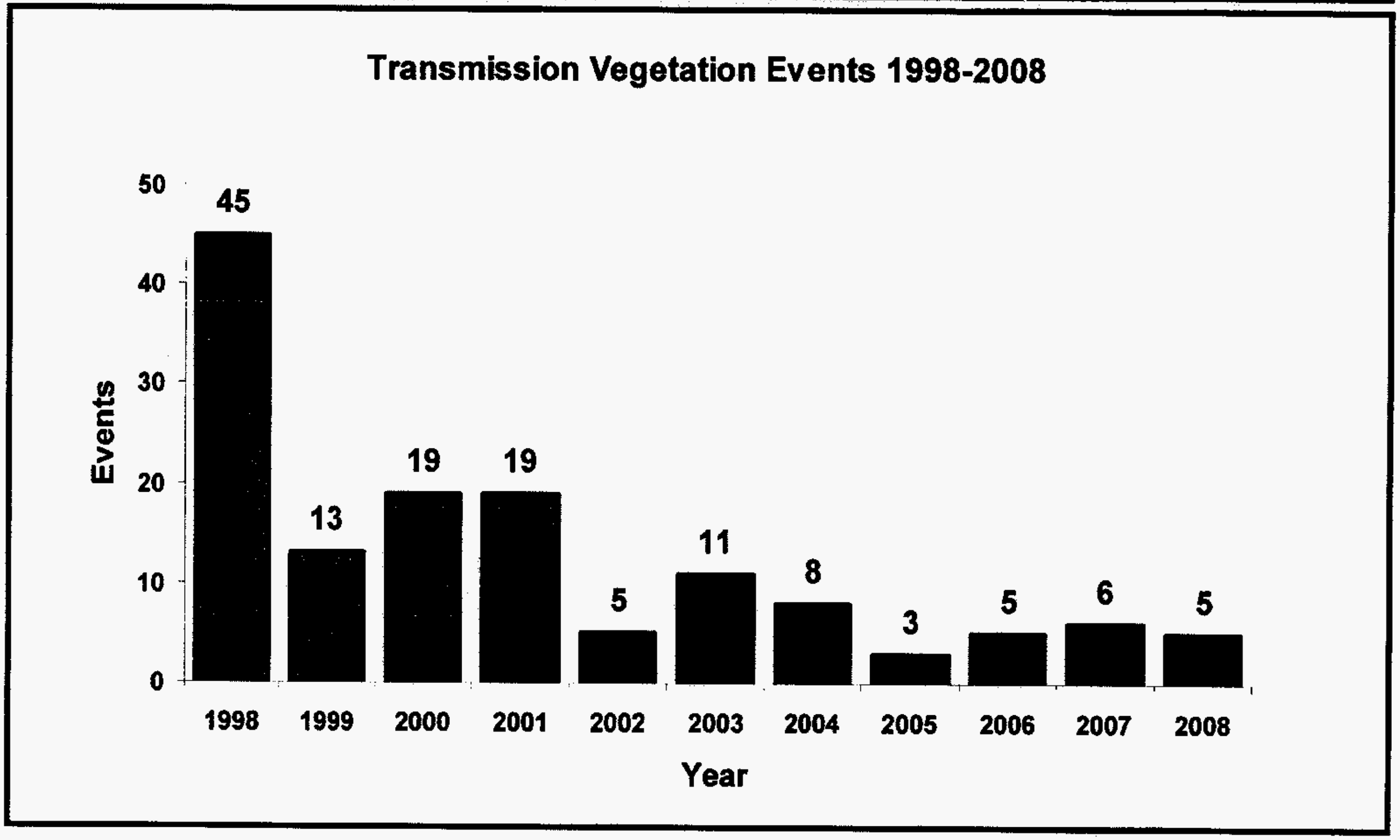
DOCKET NO. 080677-EI & 090130-EI **EXHIBIT** 101

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS James A. Keener (JAK-4)

DATE 09/02/09

FPL has reduced the number of transmission outages related to vegetation events by over 88 percent in the 1998-2008 period.



FPL attributes the success of its vegetation management program to the increased frequency of inspection work followed by remediation of risks.

Docket No. 080677-EI
Transmission Vegetation Events 1998-2008
Exhibit JAK-4, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

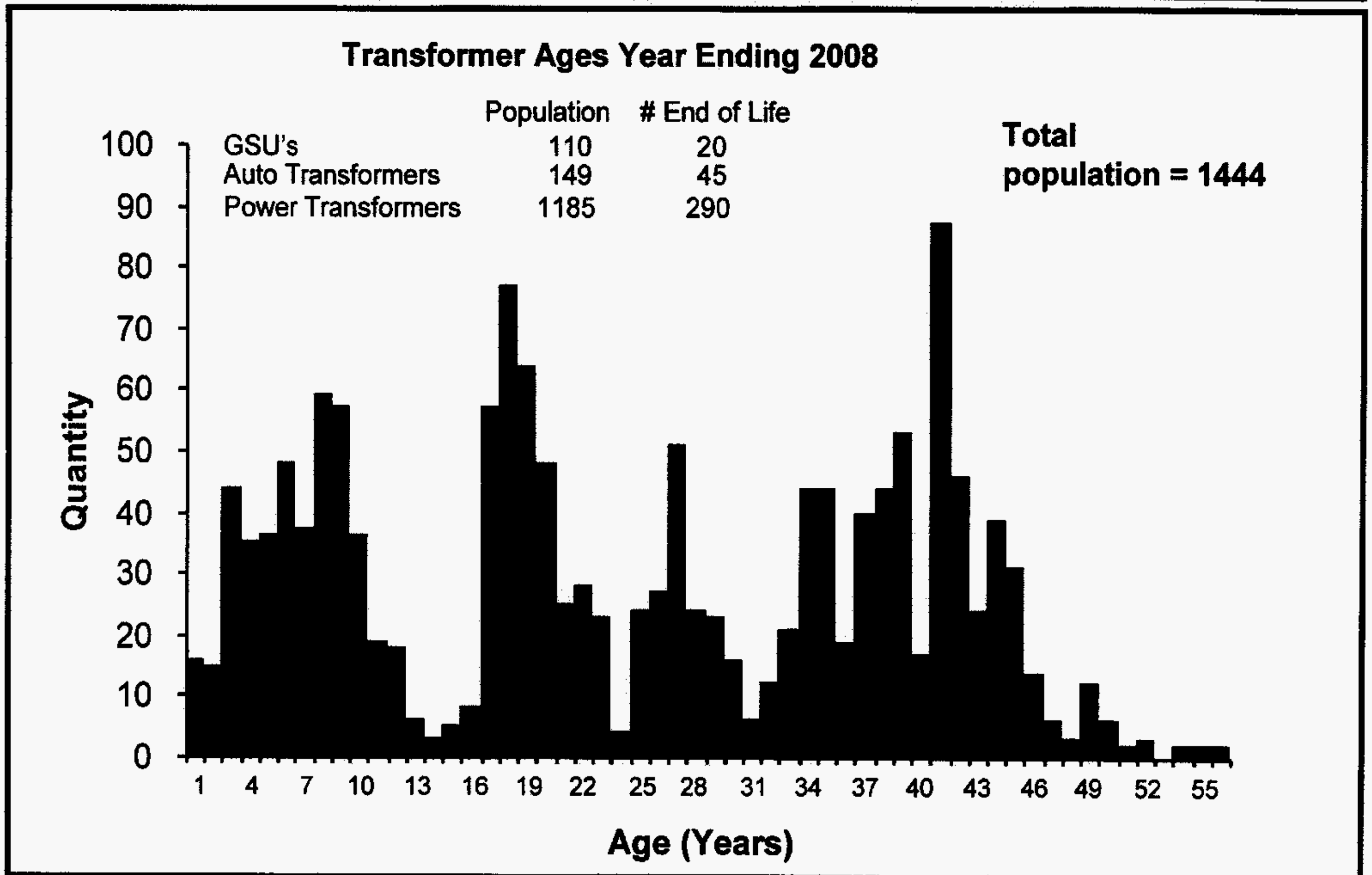
DOCKET NO. 080677-EI & 090130-EI **EXHIBIT** 102

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS James A. Keener (JAK-5)

DATE 09/02/09

FPL must replace or refurbish its aging fleet of transformers to minimize customer interruptions.



For transformers, additional end-of-life drivers besides age include water, moisture, temperature, through faults and over-excitation.

Docket No. 080677-EI
Transformer Ages Year Ending 2008
Exhibit JAK-5, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

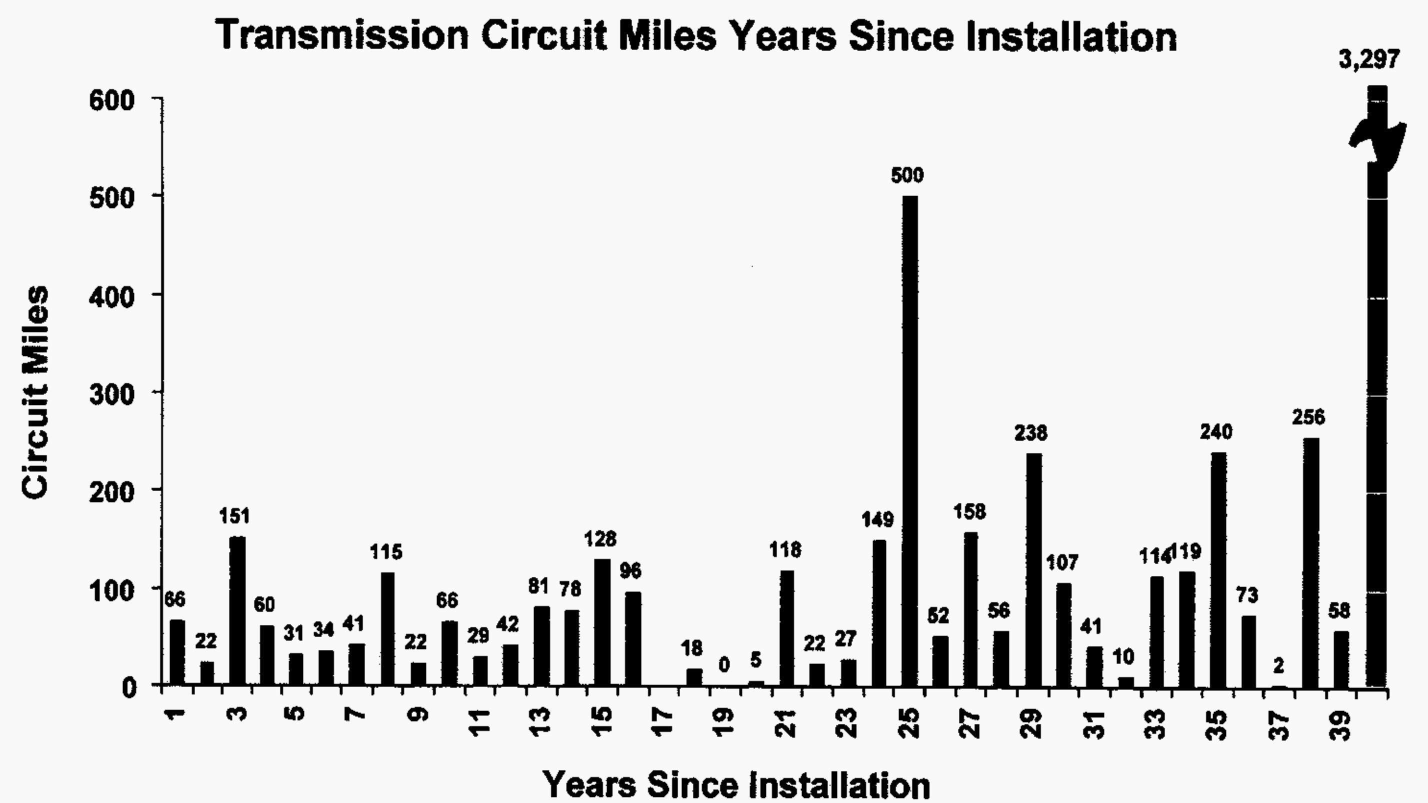
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 103

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS James A. Keener (JAK-6)

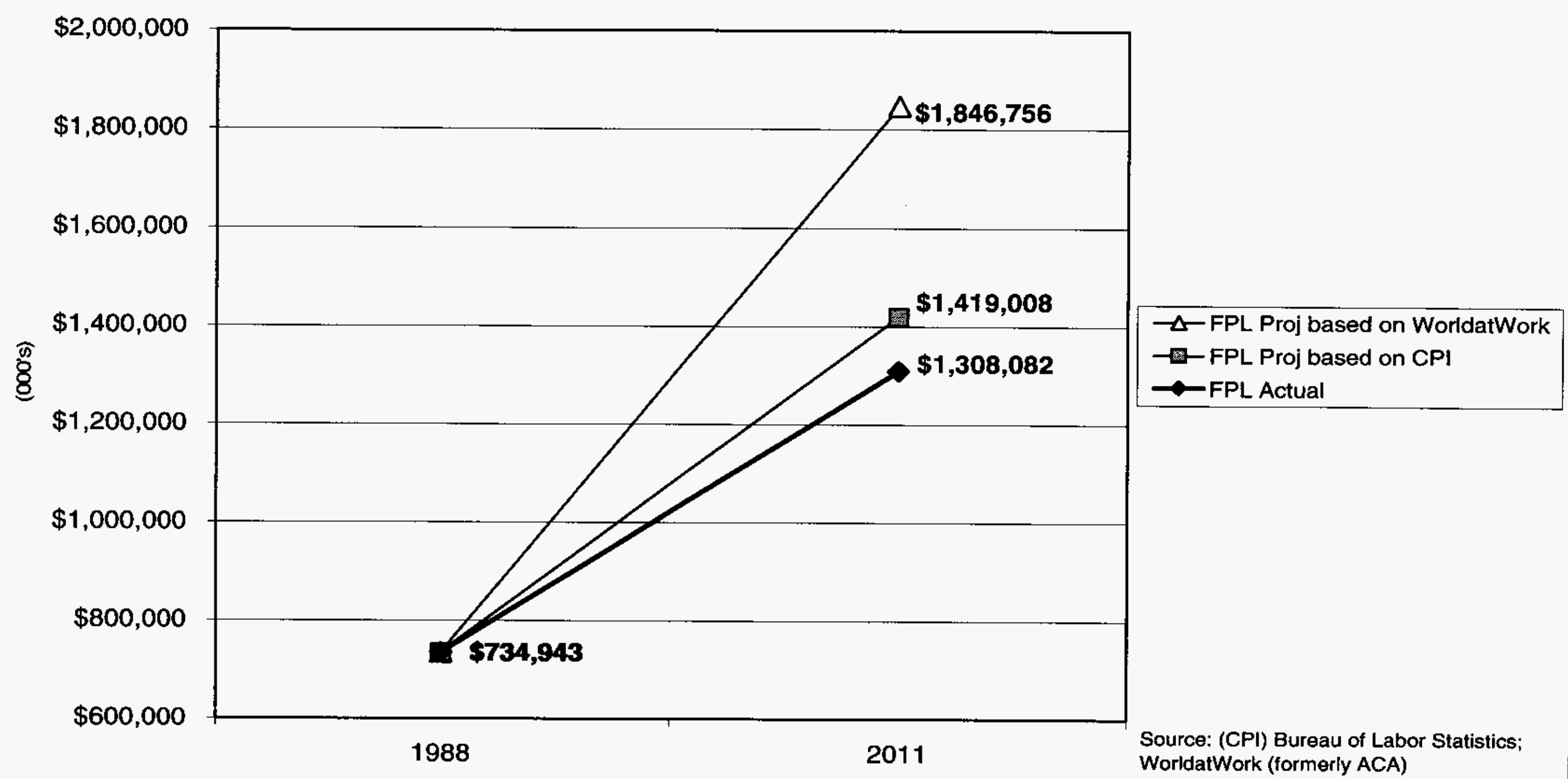
DATE 09/02/09

FPL's aging transmission infrastructure requires refurbishment to maintain current high levels of service reliability.



Approximately 60 percent of FPL's transmission lines are 30 years of age or older.

Projected Total Payroll & Benefits Costs Based on Escalation of 1988 Actuals 1988 Through 2011



Source: (CPI) Bureau of Labor Statistics; WorldatWork (formerly ACA)

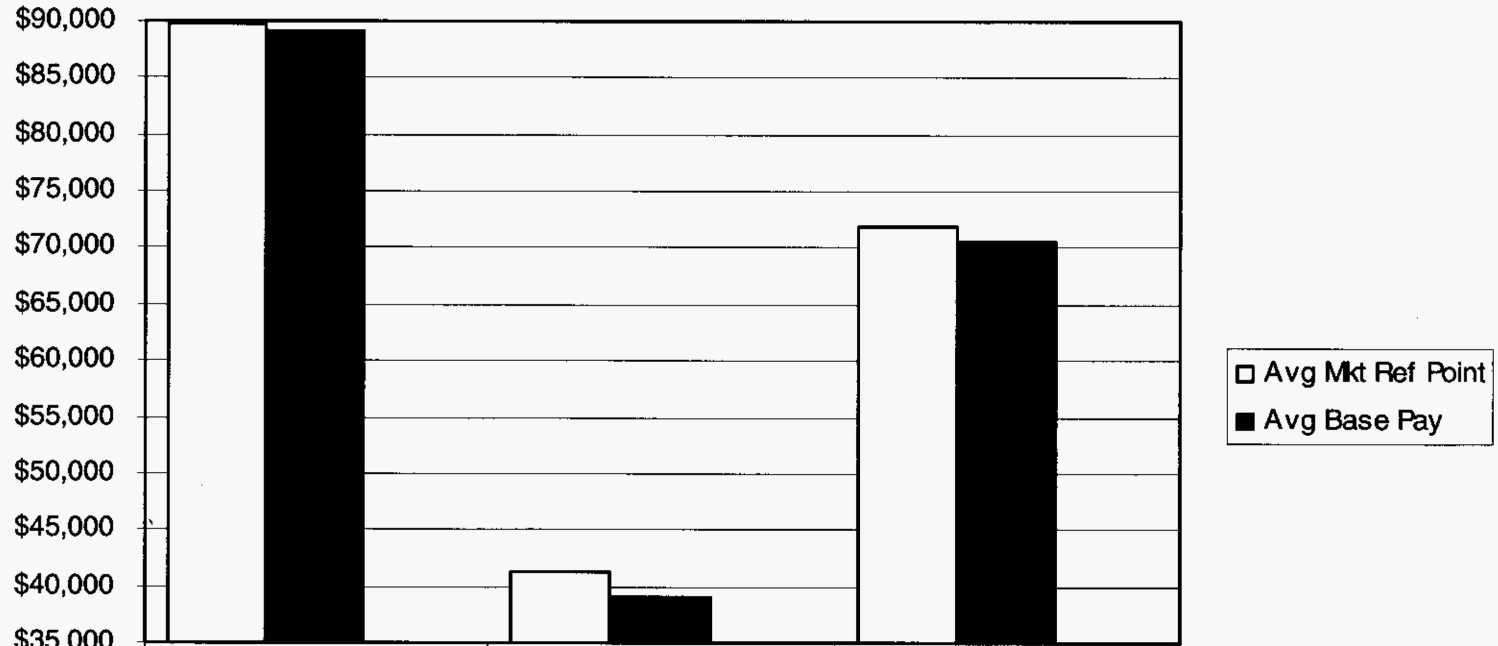
FPL has managed growth of total payroll and benefits costs below CPI and key inflation indices over the past 20 years.

Docket No. 080677_EI
Projected Total Payroll & Benefits Costs
Based on Escalation of 1988 Actuals
1988 Through 2011
Exhibit KS-1, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 104
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Kathleen M. Slattery (KS-1)
DATE 10/21/09

Docket No. 080677_EI
Position to Market (2008 Base Pay)
Exhibit KS-2, Page 1 of 1

Position to Market (2008 Base Pay)



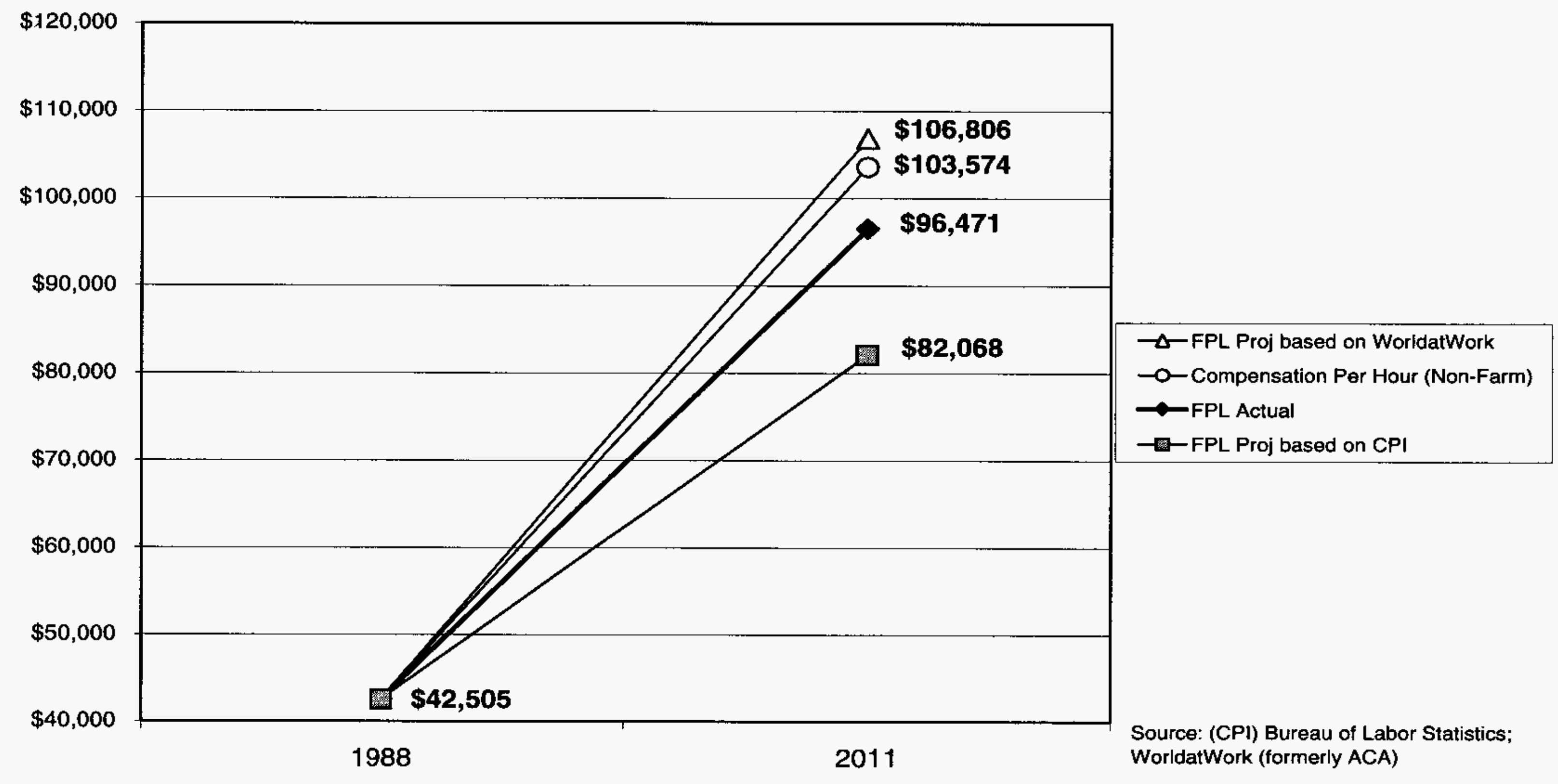
	Exempt	Non Exempt	Org Wide
Avg Mkt Ref Point	$89,851	$41,250	$71,846
Avg Base Pay	$89,086	$38,982	$70,524
Pos to Mkt	-0.9%	-5.5%	-1.8%

Market reference points are determined via benchmarking conducted internally utilizing current industry survey sources including Towers Perrin, Mercer and Watson Wyatt.

FPL's average base pay for exempt and non-exempt jobs is below market.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 105
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Kathleen M. Slattery (KS-2)
DATE 10/21/09

Projected Total Cash Compensation per Employee
Based on Escalation of 1988 Actuals
1988 Through 2011

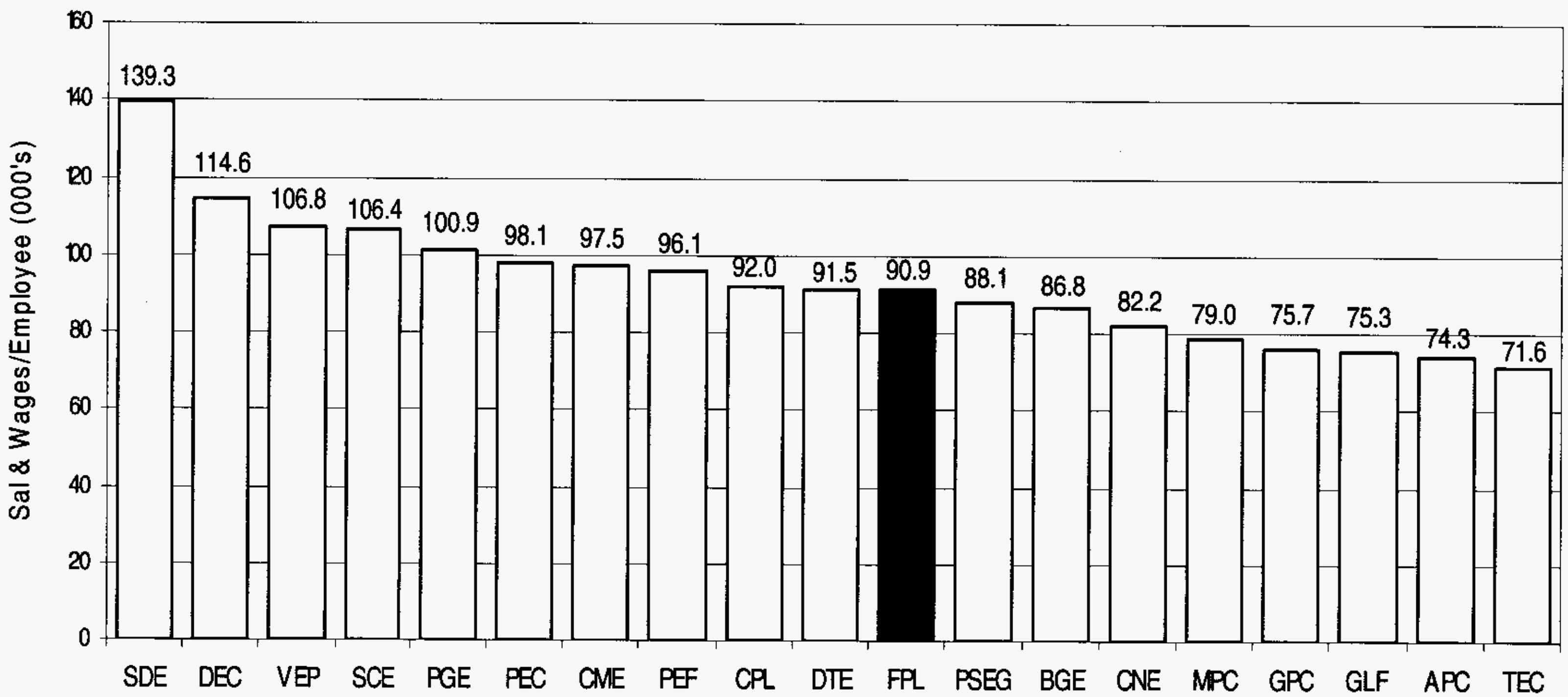


Docket No. 080677_EI
Projected Total Cash Compensation per
Employee Based on Escalation of 1988 Actuals
1988 Through 2011
Exhibit KS-3, Page 1 of 1

Growth of FPL's total compensation cost is below key wage inflation indices over the past 20 years.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 106
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Kathleen M. Slattery (KS-3)
DATE 10/21/09

FERC Total Salaries & Wages per Employee 2007



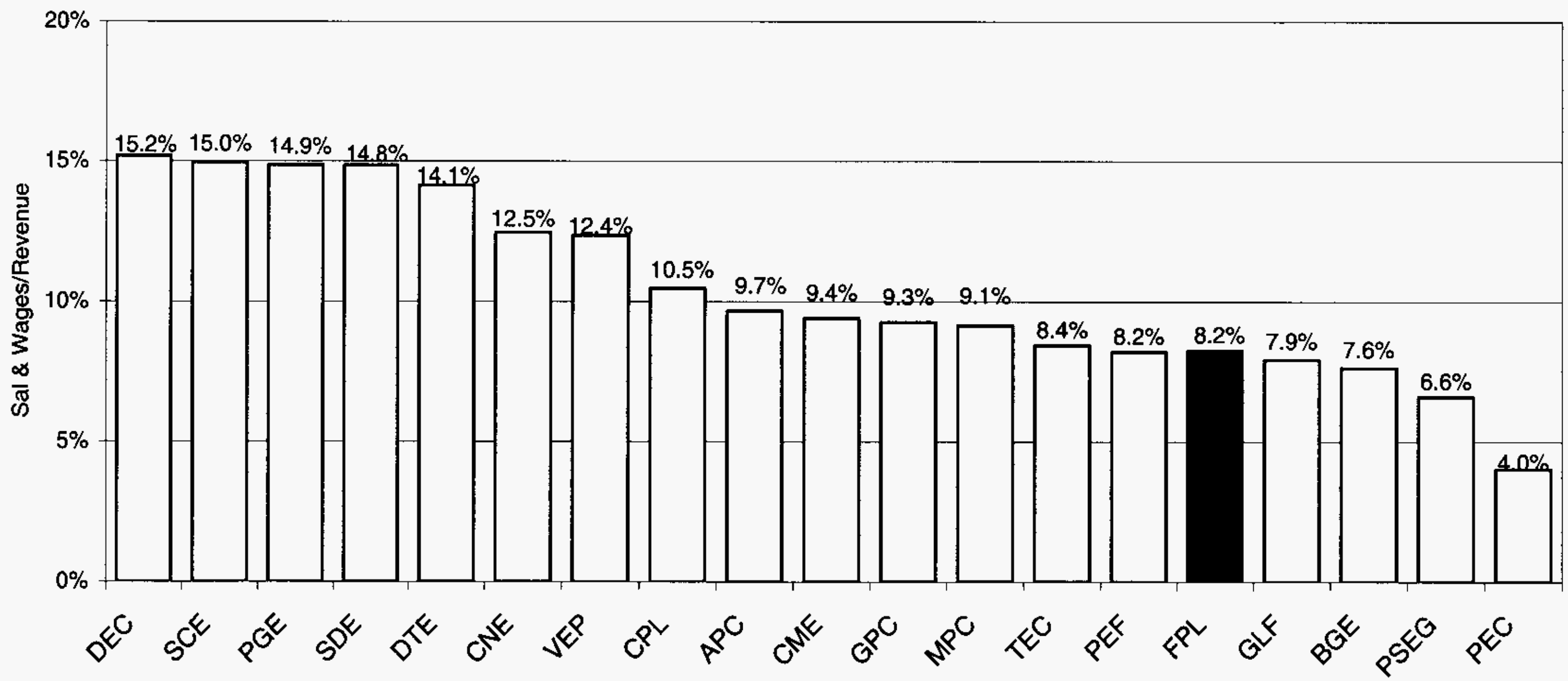
Source: FERC Form 1

APC	Alabama Power	MPC	Mississippi Power
BGE	Baltimore Gas & Electric	PGE	Pacific Gas & Electric
CPL	Carolina Power & Light	PEC	PECO Energy
CME	Commonwealth Edison	PEF	Progress Energy Florida
CNE	Consolidated Edison	PSEG	Public Service Electric & Gas
DTE	Detroit Edison	SDE	San Diego Gas & Electric
DEC	Duke Energy Corp	SCE	Southern California Edison
FPL	Florida Power & Light	TEC	Tampa Electric
GPC	Georgia Power	VEP	Virginia Electric & Power
GLF	Gulf Power		

FPL's total salaries and wages per employee is below the average of comparable utilities.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 107
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Kathleen M. Slattery (KS-4)
DATE 10/21/09

FERC Total Salaries & Wages per Operating Revenue 2007



Source: FERC Form 1

APC	Alabama Power	MPC	Mississippi Power
BGE	Baltimore Gas & Electric	PGE	Pacific Gas & Electric
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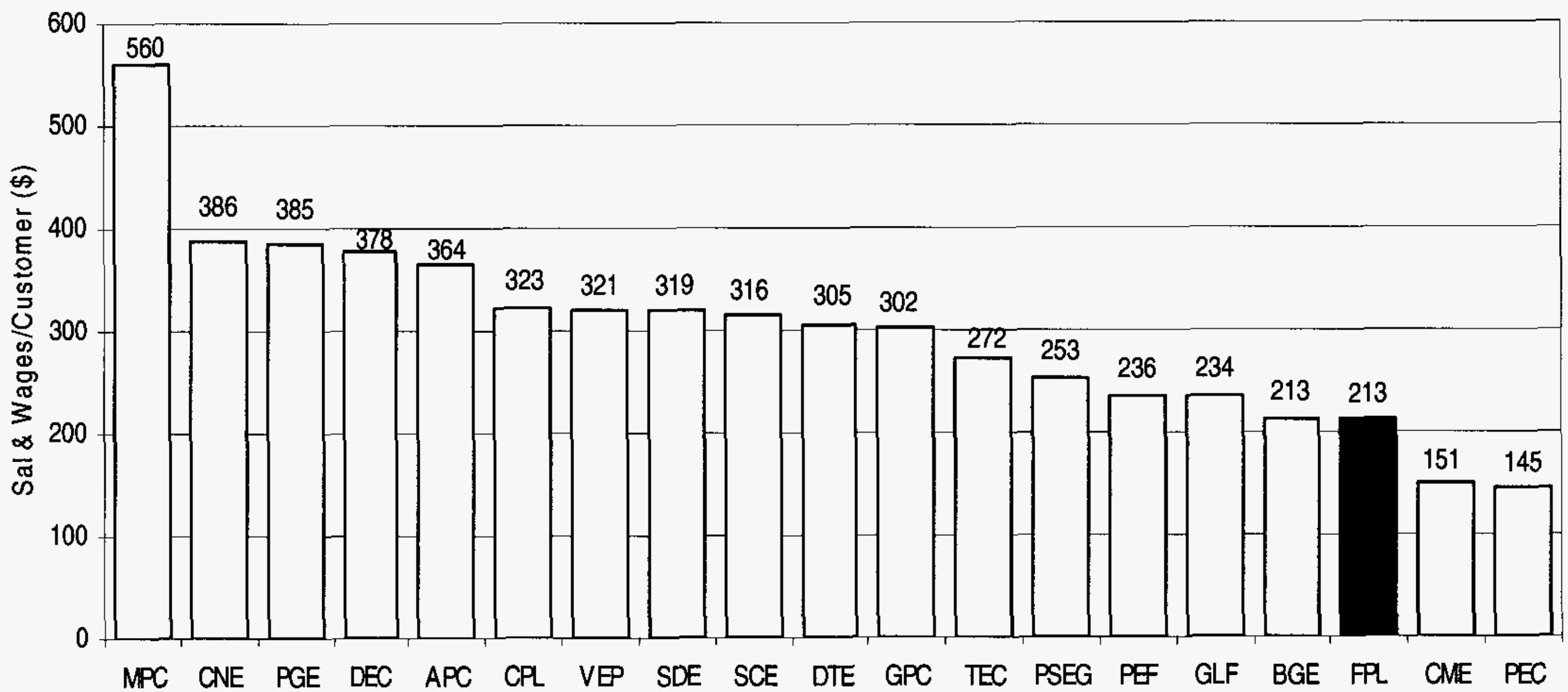
DEC	Duke Energy Corp	SCE	Southern California Edison
FPL	Florida Power & Light	TEC	Tampa Electric
GPC	Georgia Power	VEP	Virginia Electric & Power
GLF	Gulf Power		

FPL's total salaries and wages as a percent of operating revenue is considerably below comparable utilities.

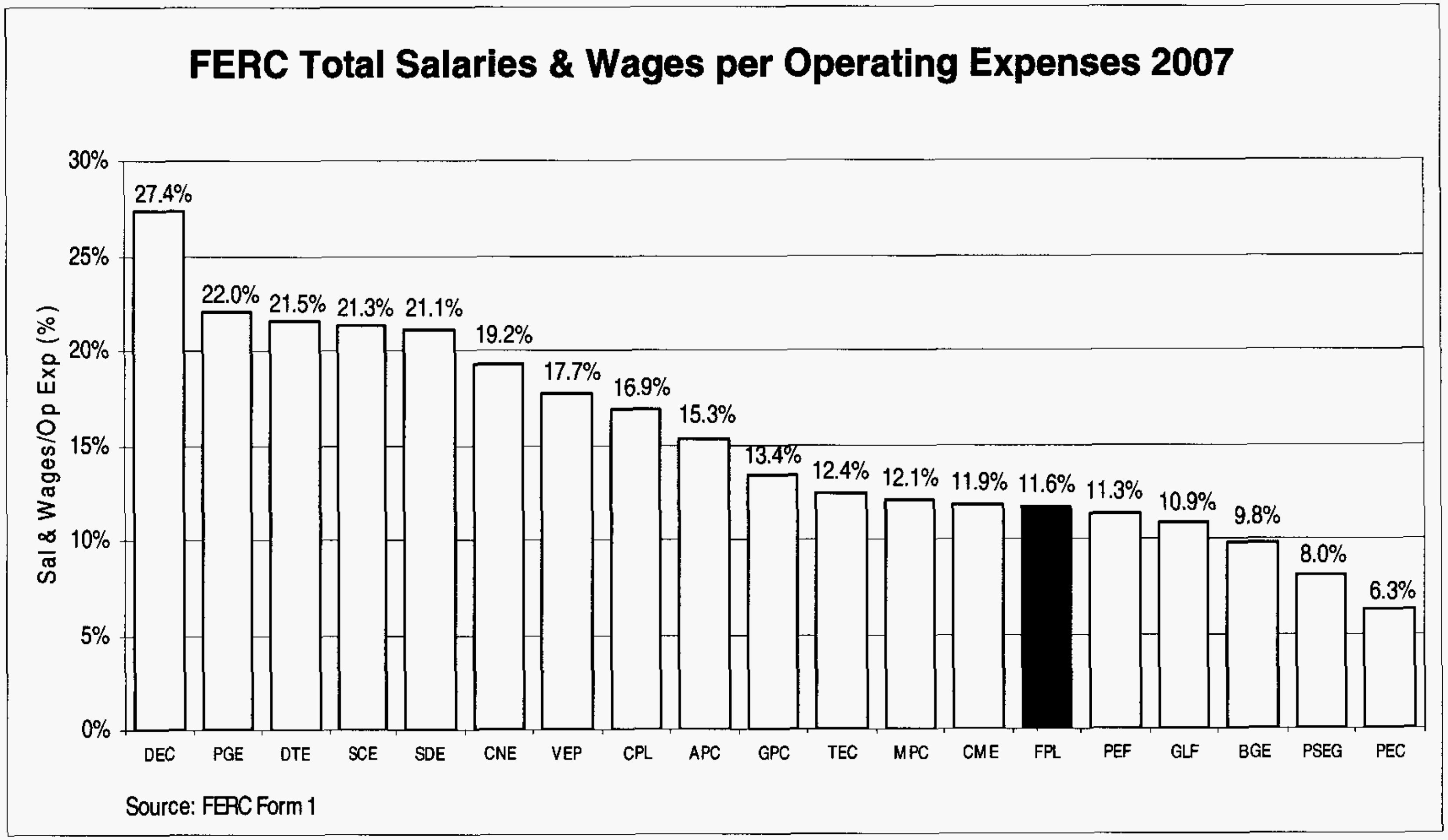
FERC Total Salaries & Wages per Customer 2007



Source: FERC Form 1

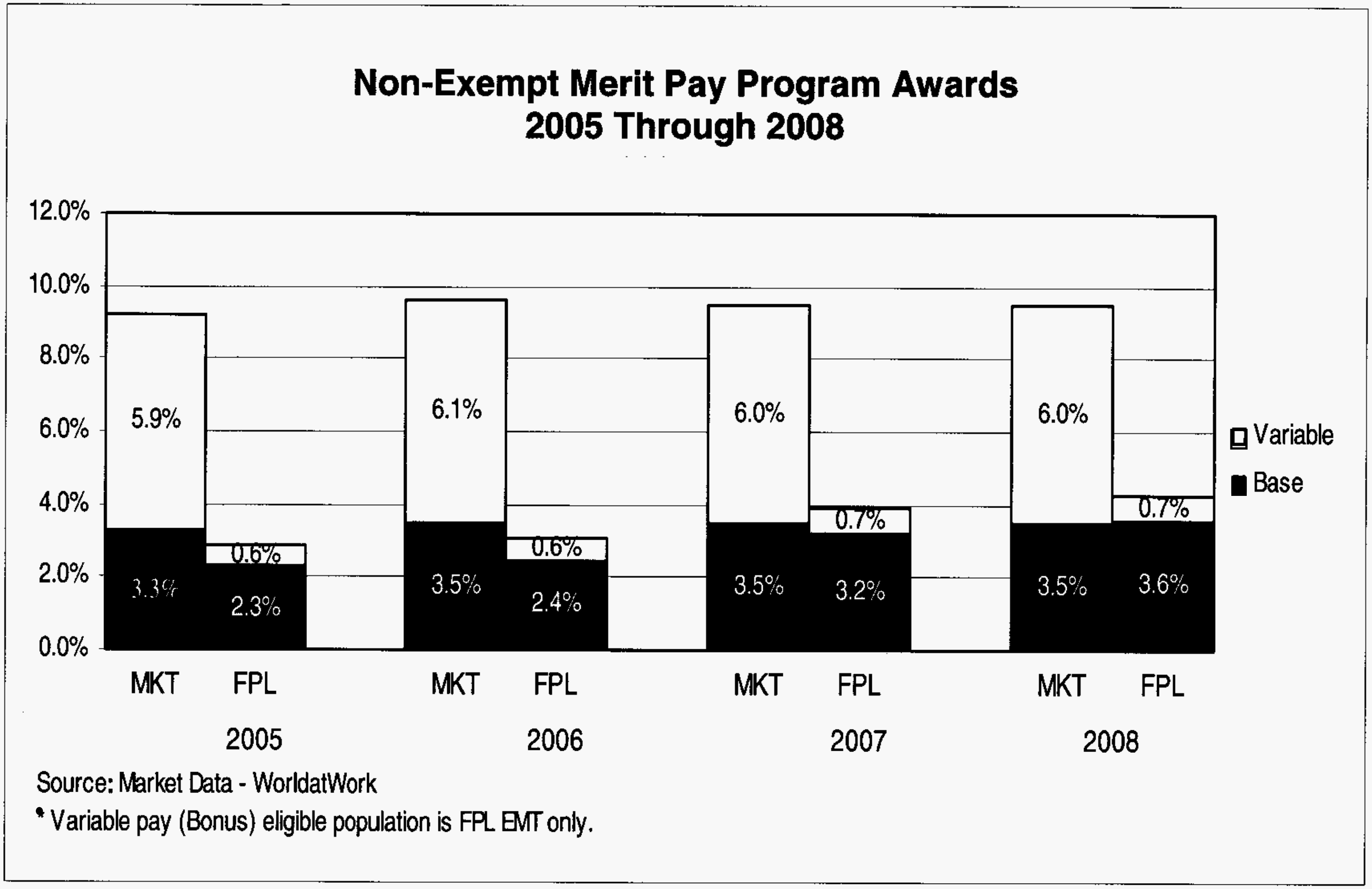
APC	Alabama Power	MPC	Mississippi Power
BGE	Baltimore Gas & Electric	PGE	Pacific Gas & Electric
CPL	Carolina Power & Light	PEC	PECO Energy
CME	Commonwealth Edison	PEF	Progress Energy Florida
CNE	Consolidated Edison	PSEG	Public Service Electric & Gas
DTE	Detroit Edison	SDE	San Diego Gas & Electric
DEC	Duke Energy Corp	SCE	Southern California Edison
FPL	Florida Power & Light	TEC	Tampa Electric
GPC	Georgia Power	VEP	Virginia Electric & Power
GLF	Gulf Power		

FPL's total salaries and wages per customer is among the lowest of comparable utilities.



APC	Alabama Power	MPC	Mississippi Power
BGE	Baltimore Gas & Electric	PGE	Pacific Gas & Electric
CPL	Carolina Power & Light	PEC	PECO Energy
CME	Commonwealth Edison	PEF	Progress Energy Florida
CNE	Consolidated Edison	PSEG	Public Service Electric & Gas
DTE	Detroit Edison	SDE	San Diego Gas & Electric
DEC	Duke Energy Corp	SCE	Southern California Edison
FPL	Florida Power & Light	TEC	Tampa Electric
GPC	Georgia Power	VEP	Virginia Electric & Power
GLF	Gulf Power		

FPL's total salaries and wages as a percent of operating expenses is considerably below the average of comparable utilities.

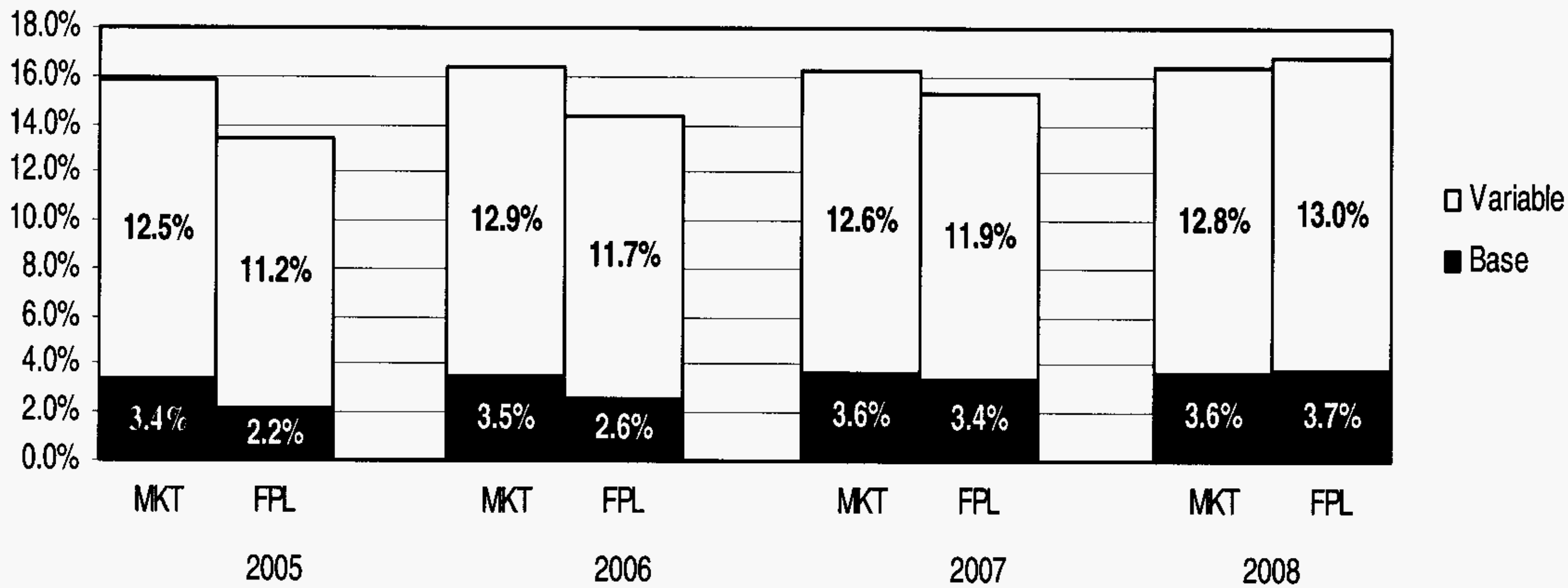


FPL's non-exempt pay program awards have been consistently below market.

Docket No. 080677_EI
Non-Exempt Merit Pay Program Awards
2005 Through 2008
Exhibit KS-5, Page 1 of 2

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 108
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Kathleen M. Slattery (KS-5)
DATE 10/21/09

Exempt Merit Pay Program Awards
2005 Through 2008

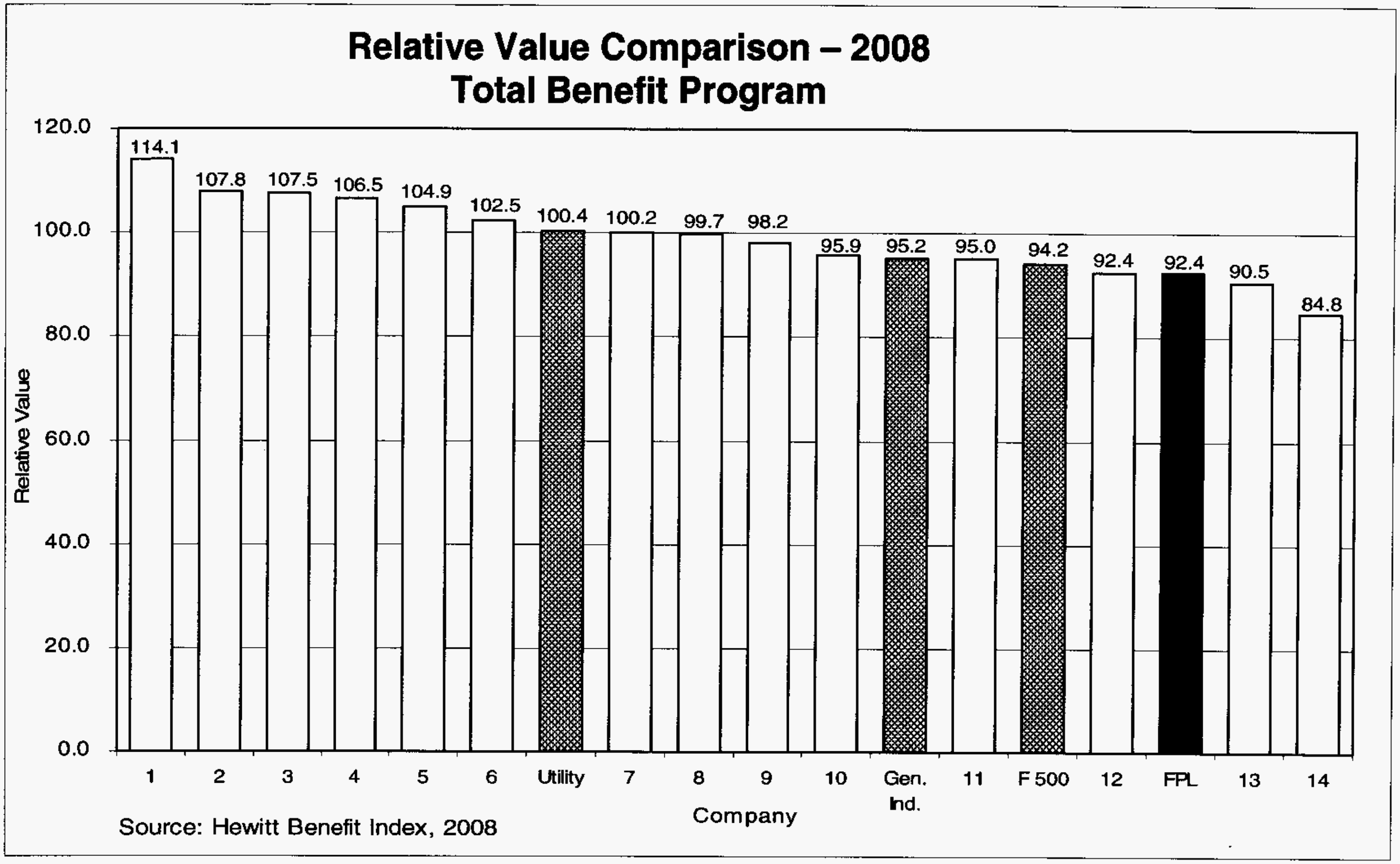


Source: Market Data - WorldatWork

FPL's exempt pay program awards have been consistently at or below market.

Docket No. 080677_EI
Exempt Merit Pay Program Awards
2005 Through 2008
Exhibit KS-5, Page 2 of 2

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI **EXHIBIT** 109
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Kathleen M. Slattery (KS-6)
DATE 10/21/09



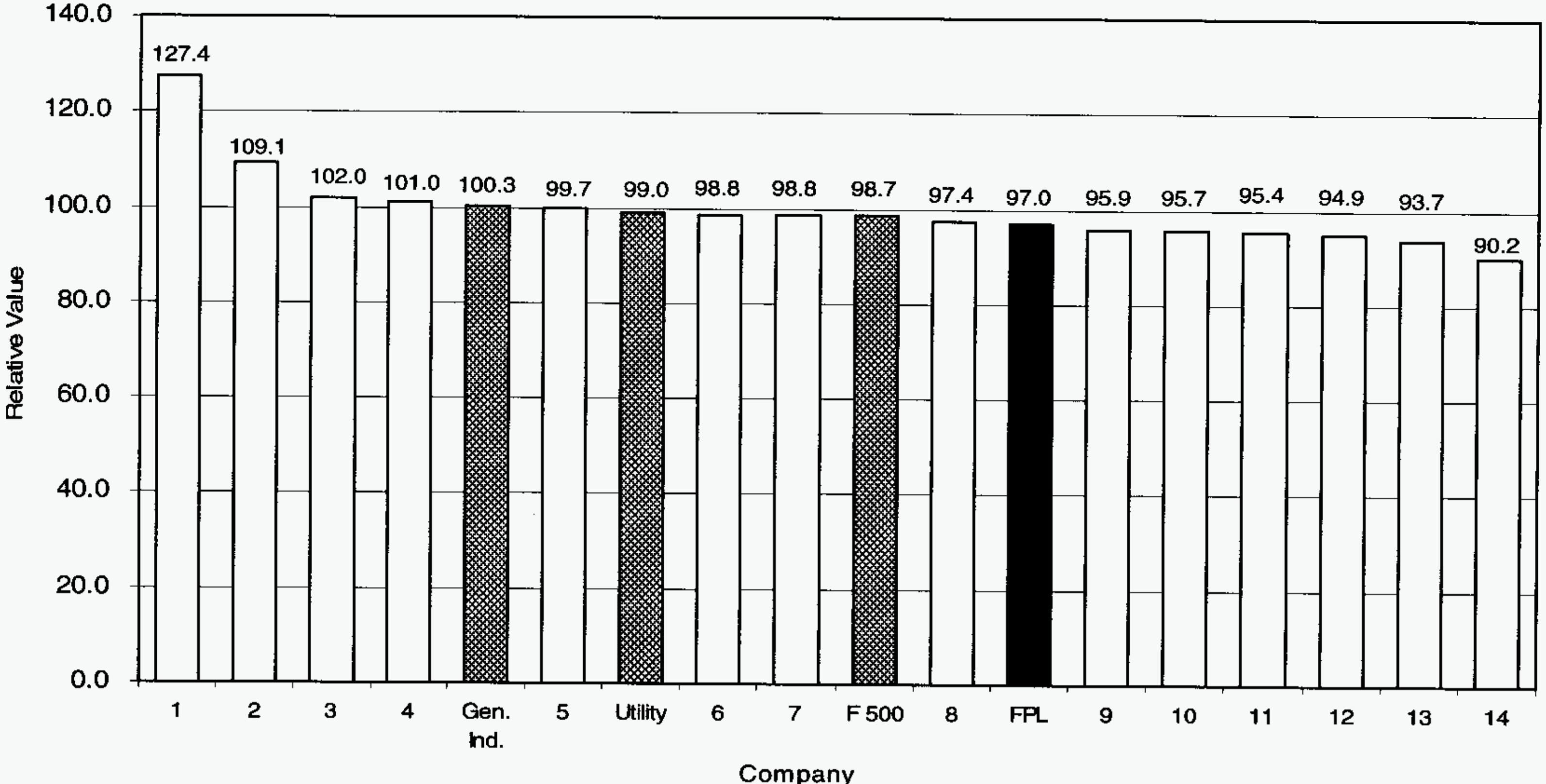
- Comparison includes Company Contributions to determine "value" within the Benefit Index Methodology.

- Comparator Group Average = 100. Companies Included in Comparator Group: American Electric Power, Consolidated Edison, Constellation Energy, Dominion Resources, Duke Energy, Energy Future Holdings, Entergy, Exelon, FirstEnergy, PG&E, Progress Energy, Public Service Enterprise, Reliant Energy, Southern Company

The relative value of FPL's benefit programs is below those of comparable utility, general industry, and Fortune 500 companies.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 110
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Kathleen M. Slattery (KS-7)
DATE 10/21/09

Relative Value Comparison – 2008
Active Employee Medical Plan



Source: Hewitt Benefit Index, 2008

- Comparison includes Company Contributions to determine "value" within the Benefit Index Methodology.
- Comparator Group Average = 100. Companies Included in Comparator Group: American Electric Power, Consolidated Edison, Constellation Energy, Dominion Resources, Duke Energy, Energy Future Holdings, Entergy, Exelon, FirstEnergy, PG&E, Progress Energy, Public Service Enterprise, Reliant Energy, Southern Company

The relative value of FPL's medical plan is below those of comparable utility, general industry, and Fortune 500 companies.

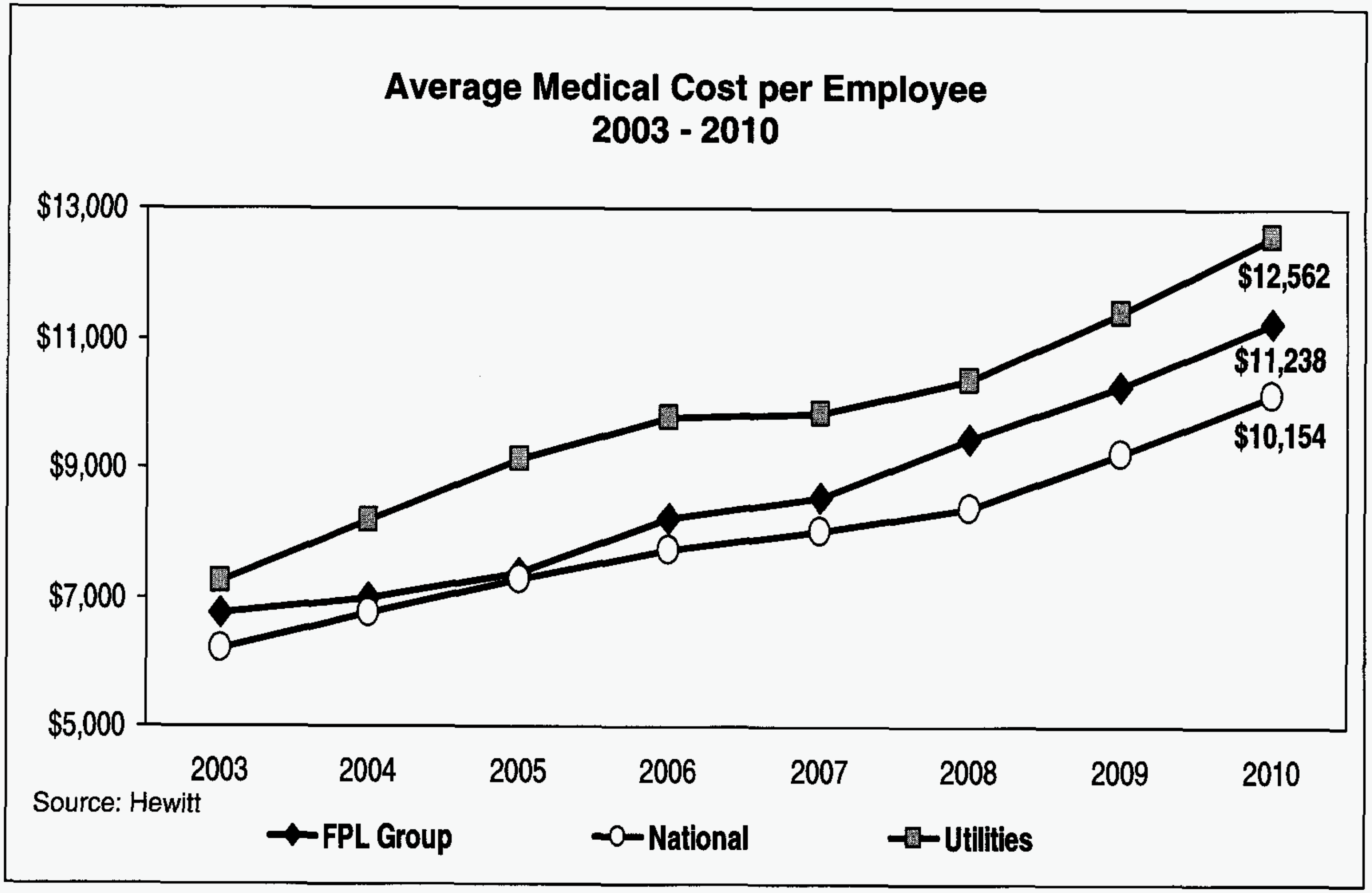
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080677-EI & 090130-EI EXHIBIT 111

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS Kathleen M. Slattery (KS-8)

DATE 10/21/09

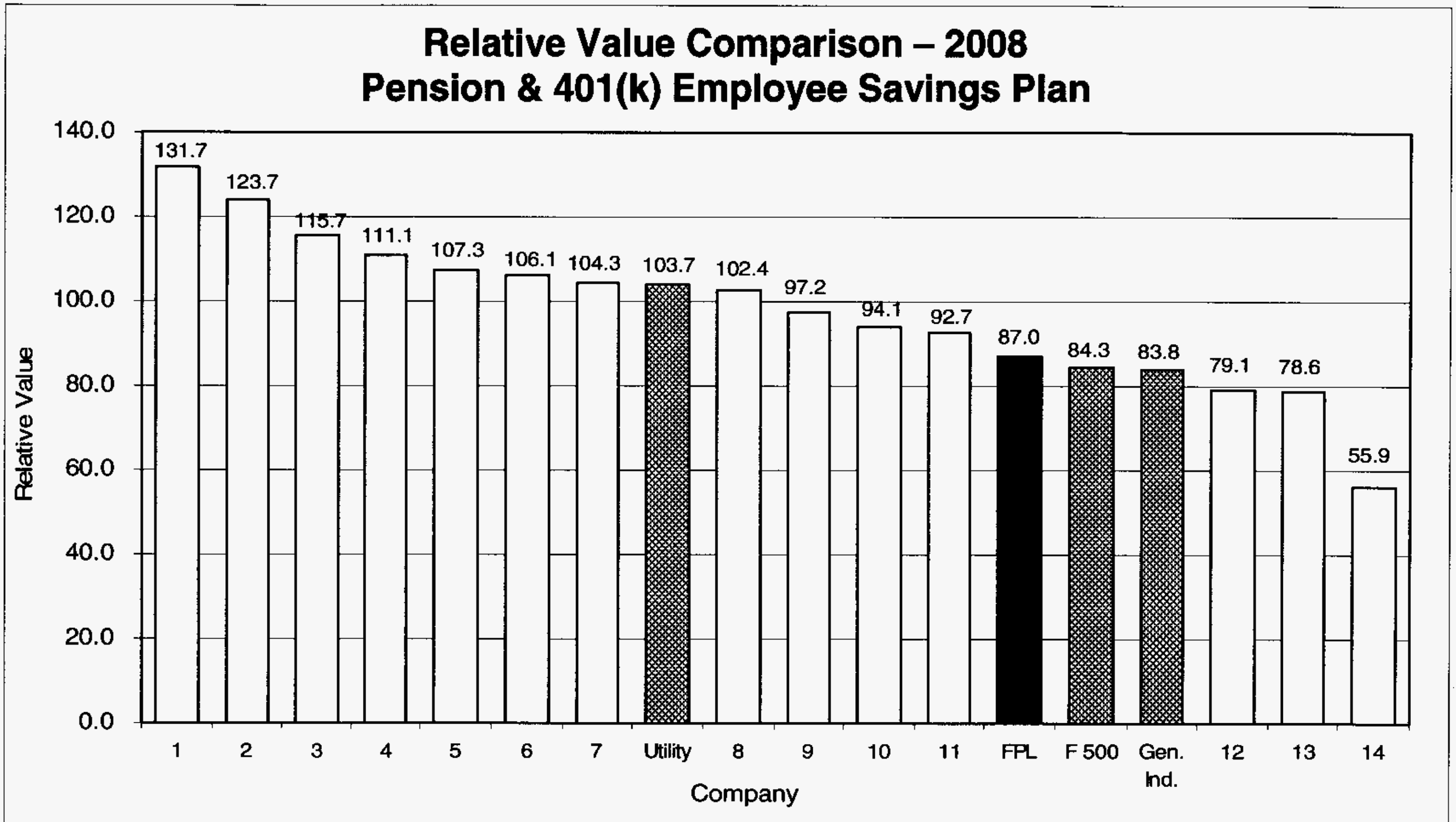


FPL's medical plan cost per employee has been consistently below utility industry benchmarks.

Docket No. 080677_EI
Average Medical Cost per Employee
2003-2010
Exhibit KS-8, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 112
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Kathleen M. Slattery (KS-9)
DATE 10/21/09

Docket No. 080677_EI
Relative Value Comparison – 2008
Pension & 401(k) Employee Savings Plan
Exhibit KS-9, Page 1 of 1



Source: Hewitt Benefit Index, 2008

- Comparison includes Company Contributions to determine "value" within the Benefit Index Methodology.
- Comparator Group Average = 100. Companies Included in Comparator Group: American Electric Power, Consolidated Edison, Constellation Energy, Dominion Resources, Duke Energy, Energy Future Holdings, Entergy, Exelon, FirstEnergy, PG&E, Progress Energy, Public Service Enterprise, Reliant Energy, Southern Company

The relative value of FPL's retirement plans is well below those of other utilities and comparable to those of general industry and Fortune 500 companies.

FLORIDA PUBLIC SERVICE COMMISSION

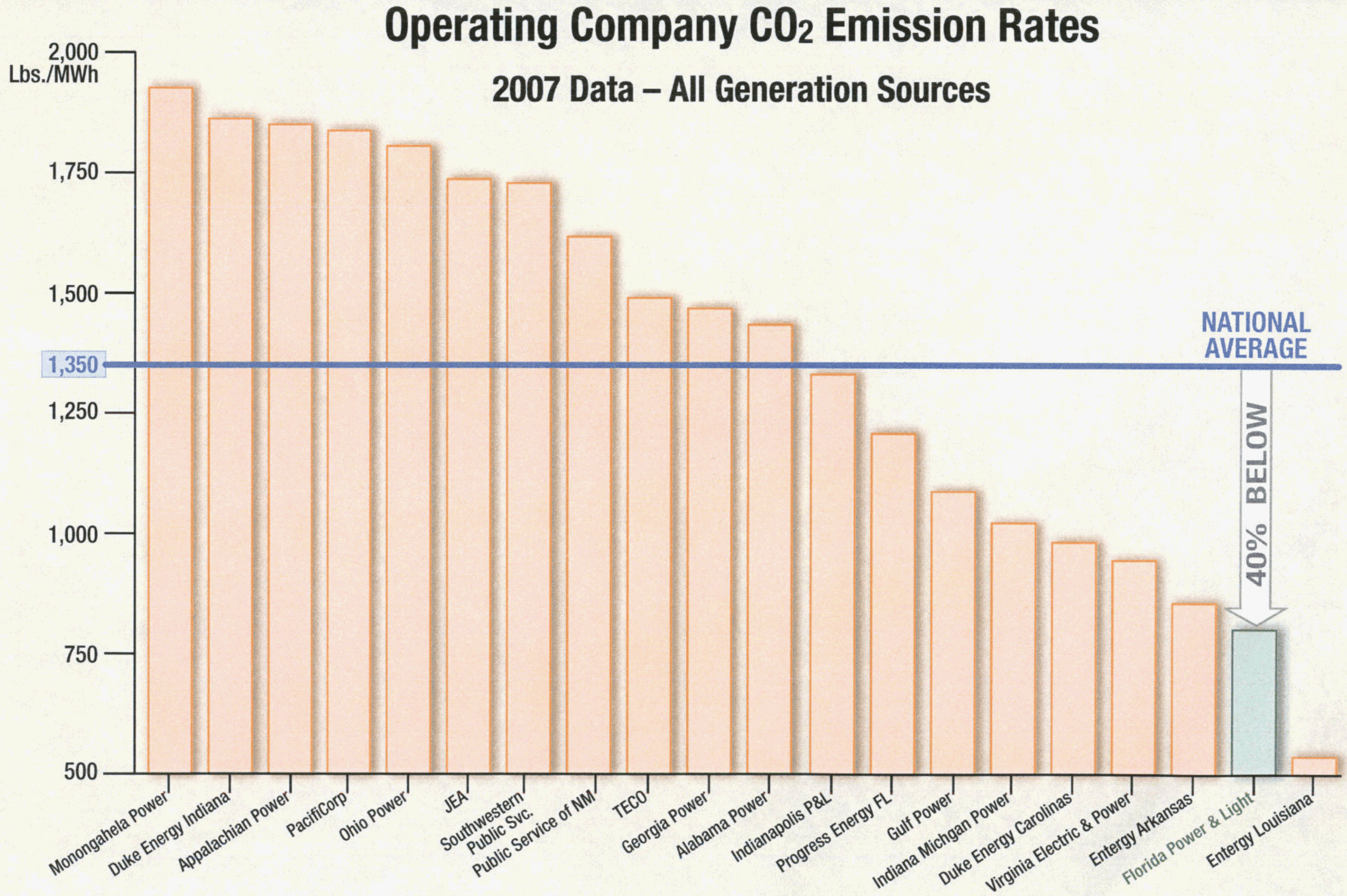
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 113

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS Christopher A. Bennett (CAB-1)

DATE 09/03/09

FPL's CO_2 Emission Rates Among Lowest in Nation



Source: 2007 DOE EIA forms 906 & 920

Docket No. 080677-EI
Operating Company CO_2
Emissions Rates
Exhibit CAB-1, Page 1 of 1

Six Sigma DMAIC Process Map

DEFINE	MEASURE	ANALYZE	IMPROVE	CONTROL
Project Scope & Problem Validation	Refine the Project	Failure Modes & Effects Analysis	Design & Execute and Experiment	Optimize & Refine Solutions
Problem Statement	Process Maps & Simplification	ID Variation: Graphical Analysis	Define Y = f(x)	Control X's & Monitor Y's
Project Metrics	Cause & Effect for Variable Reduction	ID Variation: Statistical Analysis	Recommend Changes	Close & Hand-Off Project
Objective Statement(s)	Measurement Capability	Plan For Design of Experiments		
Team Members	Data Collection Systems			
	Process Capability			

Docket No. 080677-EI
Six Sigma DMAIC Process Map
Exhibit CAB-2, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 114
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Christopher A. Bennett (CAB-2)
DATE 09/03/09

FLORIDA POWER & LIGHT COMPANY

JUNO BEACH, FLORIDA

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS

RELATED TO ELECTRIC PLANT

AS OF DECEMBER 31, 2009

Note: Filed on March 17, 2009, due to Commission timing requirements for this study and not duplicated separately due to volume.

Gannett Fleming
Valuation and Rate Division

Harrisburg, Pennsylvania   Calgary, Alberta   Valley Forge, Pennsylvania

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 115
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS C. Richard Clarke (CRC-1)
DATE 09/03/09

LIST OF CASES IN WHICH RICHARD CLARKE SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
1.	1981	FERC	ER 81-177	Southern California Edison	Depreciation
2.	1982	FERC	ER 82-427	Southern California Edison	Depreciation
3.	1982	Ca. PUC	82-02-040	Southern California Edison	Nuclear Plant Investment
4.	1984	FERC	ER 84-075	Southern California Edison	Depreciation and Decommissioning
5.	1985	Ca. PUC	85-05-144	Southern California Edison	Nuclear Plant Investment
6.	1985	Ca. PUC	85-05-008	Southern California Edison	SONGS Nuclear Plant Recovery
7.	1986	Ca. PUC	86-12-047	Southern California Edison	Depreciation and Decommissioning
8.	1989	Ca. PUC	89-03-026	Southern California Edison	Transmission Plant Recovery
9.	1990	Ca. PUC	90-12-018	Southern California Edison	Depreciation and Rate Base
10.	1993	Ca. PUC	93-12-025	Southern California Edison	Depreciation and Rate Base
11.	1993	Ca. PUC	93-12-029	Southern California Edison	Performance Based Ratemaking
12.	1996	Ca. PUC	96-08-007	Southern California Edison	Generation Sunk Costs
13.	1997	Ca. PUC	97-10-024	Southern California Edison	1996 Capital Additions Recovery
14.	1997	Ca. PUC	97-08-056	Southern California Edison	Cost Separation
15.	1999	Ca. PUC	99-04-024	Southern California Edison	1997-98 Capital Addition Recovery
16.	2002	Ca. PUC	02-03-039	Southern California Edison	Nuclear Decommissioning Costs
17.	2002	Ca. PUC	02-05-004	Southern California Edison	Depreciation and Rate Base
18.	2005	FERC	EL00-105-007	Southern California Edison	Accounting
19.	2006	Nv. PUC	05-10003	Sierra Pacific Power Co.	Depreciation of Electric Plant
20.	2006	Nv. PUC	05-10005	Sierra Pacific Power Co.	Depreciation of Gas Plant
21.	2007	Nv. PUC	06-11023	Nevada Power Company	Depreciation of Electric Plant
22	2008	Nv. PUC	07-09030	Southwest Gas Company	Depreciation of Gas Property
23	2008	WUTC	072300	Puget Sound Energy	Depreciation of Electric & Gas Property

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 116
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS C. Richard Clarke (CRC-2)
DATE 09/03/09

MFRs AND SCHEDULES SPONSORED AND CO-SPONSORED BY KIM OUSDAHL

MFR #	PERIOD	TITLE
SOLE SPONSORSHIP:		
B-1	2008 Historic 2009 Prior 2010 Test	ADJUSTED RATE BASE
B-3	2008 Historic	13-MONTH AVERAGE BALANCE SHEET – SYSTEM BASIS
B-4	2008 Historic	TWO YEAR HISTORICAL BALANCE SHEET
B-18	2008 Historic	FUEL INVENTORY BY PLANT
B-19	2010 Test	MISCELLANEOUS DEFERRED DEBITS
B-20	2010 Test	OTHER DEFERRED CREDITS
B-21	2008 Historic	ACCUMULATED PROVISION ACCOUNTS – 228.1, 228.2 AND 228.4
B-25	2010 Test & 2009 Prior	ACCOUNTING POLICY CHANGES AFFECTING RATE BASE
C-1	2008 Historic 2009 Prior 2010 Test	ADJUSTED JURISDICTIONAL NET OPERATING INCOME
C-2	2008 Historic 2009 Prior 2010 Test	NET OPERATING INCOME ADJUSTMENTS
C-3	2008 Historic 2009 Prior 2010 Test	JURISDICTIONAL NET OPERATING INCOME ADJUSTMENTS
C-7	2010 Test	OPERATION AND MAINTENANCE EXPENSES
C-9	2008 Historic	FIVE YEAR ANALYSIS-CHANGE IN COST
C-13	2008 Historic	MISCELLANEOUS GENERAL EXPENSES
C-15	2008 Historic	INDUSTRY ASSOCIATION DUES
C-18	2008 Historic	LOBBYING EXPENSES, OTHER POLITICAL EXPENSES AND CIVIC/CHARITABLE CONTRIBUTIONS
C-20	2008 Historic	TAXES OTHER THAN INCOME TAXES
C-22	2008 Historic 2010 Test	STATE AND FEDERAL INCOME TAX CALCULATION

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 117
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Kim Ousdahl (KO-1)
DATE 09/04/09

MFRs AND SCHEDULES SPONSORED AND CO-SPONSORED BY KIM OUSDAHL

MFR #	Period	TITLE
SOLE SPONSORSHIP:		
C-24	2008 Historic 2010 Test	PARENT(S) DEBT INFORMATION
C-25	2010 Test, 2009 Prior, 2008 Historic	DEFERRED TAX ADJUSTMENT
C-26	2008 Historic	INCOME TAX RETURNS
C-27	2010 Test	CONSOLIDATED TAX INFORMATION
C-28	2008 Historic	MISCELLANEOUS TAX INFORMATION
C-30	2010 Test	TRANSACTIONS WITH AFFILIATED COMPANIES
C-31	2010 Test & 2008 Historic	AFFILIATED COMPANY RELATIONSHIPS
C-32	2010 Test & 2008 Historic	NON-UTILITY OPERATIONS UTILIZING UTILITY ASSETS
C-38	2010 Test	O&M ADJUSTMENTS BY FUNCTION
C-39	2008 Historic	BENCHMARK YEAR RECOVERABLE O&M EXPENSES BY FUNCTION
C-44	2010 Test	REVENUE EXPANSION FACTOR
D-1b	2010 Test, 2009 Prior, 2008 Historic	COST OF CAPITAL – ADJUSTMENTS
D-4a	2008 Historic	LONG-TERM DEBT OUTSTANDING
F-1	2008 Historic	ANNUAL AND QUARTERLY REPORT TO SHAREHOLDERS
F-2	2008 Historic	SEC REPORTS
JOINT OR CO-SPONSORSHIP:		
A-1	2010 Test	FULL REV REQUIREMENTS INCREASE REQUESTED
B-2	2008 Historic 2009 Prior 2010 Test	RATE BASE ADJUSTMENTS
B-6	2008 Historic 2010 Test	JURSIDICTIONAL SEPARATION FACTORS – RATE BASE
B-15	2010 Test & 2009 Prior	PROPERTY HELD FOR FUTURE USE – 13 MONTH AVG

MFRs AND SCHEDULES SPONSORED AND CO-SPONSORED BY KIM OUSDAHL

MFR #	Period	TITLE
JOINT OR CO-SPONSORSHIP:		
B-17	2010 Test & 2009 Prior	WORKING CAPITAL – 13 MONTH AVG
B-22	2010 Test & 2008 Historic	TOTAL ACCUMULATED DEFERRED INCOME TAXES
B-23	2010 Test, 2009 Prior, 2008 Historic	INVESTMENT TAX CREDITS – ANNUAL ANALYSIS
C-4	2008 Historic 2010 Test	JURISDICTIONAL SEPARATION FACTORS – NET OPERATING INCOME
C-8	2010 Test & 2009 Prior	DETAIL OF CHANGES IN EXPENSES
C-6	2010 Test, 2009 Prior, 2008 Historic	BUDGETED VERSUS ACTUAL OPERATING REVENUES AND EXPENSES
C-10	2010 Test	DETAIL OF RATE CASE EXPENSES FOR OUTSIDE CONSULTANTS
C-12	2010 Test & 2008 Historic	ADMINISTRATIVE EXPENSES
C-16	2008 Historic	OUTSIDE PROFESSIONAL SERVICES
C-17	2010 Test & 2008 Historic	PENSION COST
C-18	2010 Test	LOBBYING EXPENSES, OTHER POLITICAL EXPENSES AND CIVIC/CHARITABLE CONTRIBUTIONS
C-21	2010 Test, 2009 Prior, 2008 Historic	REVENUE TAXES
C-23	2010 Test & 2008 Historic	INTEREST IN TAX EXPENSE CALCULATION
C-29	2010 Test, 2009 Prior, 2008 Historic	GAINS AND LOSSES ON DISPOSITION OF PLANT AND PROPERTY
C-33	2010 Test, 2009 Prior, 2008 Historic	PERFORMANCE INDICES
C-36	2010 Test, 2009 Prior, 2008 Historic	NON-FUEL OPERATION AND MAINTENANCE EXPENSE COMPARED TO CPI
C-37	2010 Test	O&M BENCHMARK COMPARISON BY FUNCTION
C-41	2010 Test	O&M BENCHMARK VARIANCE BY FUNCTION
C-42	2010 Test, 2009 Prior, 2008 Historic	HEDGING COSTS

MFRs AND SCHEDULES SPONSORED AND CO-SPONSORED BY KIM OUSDAHL

MFR #	Period	TITLE
JOINT OR CO-SPONSORSHIP:		
C-43	2010 Test, 2009 Prior, 2008 Historic	SECURITY COSTS
D-1a	2008 Historical 2009 Prior 2010 Test	COST OF CAPITAL – 13 MONTH AVG
D-4b	2010 Test & 2009 Prior	REACQUIRED BONDS
F-5	2010 Test	FORECASTING MODELS
F-8	2010 Test	ASSUMPTIONS

	Period	TITLE
2011 WEST COUNTY UNIT 3 SPONSORED OR CO-SPONSORED:		
A-1	2011 West County Unit 3	FULL REV REQUIREMENTS INCREASE REQUESTED
B-1	2011 West County Unit 3	ADJUSTED RATE BASE
B-6	2011 West County Unit 3	JURISDICTIONAL SEPARATION FACTORS – RATE BASE
C-1	2011 West County Unit 3	ADJUSTED JURISDICTIONAL NET OPERATING INCOME
C-4	2011 West County Unit 3	JURISDICTIONAL SEPARATION FACTORS – NET OPERATING INCOME
C-22	2011 West County Unit 3	STATE AND FEDERAL INCOME TAX CALCULATION
C-23	2011 West County Unit 3	INTEREST IN TAX EXPENSE CALCULATION
C-44	2011 West County Unit 3	REVENUE EXPANSION FACTOR
D-1a	2011 West County Unit 3	COST OF CAPITAL – 13 MONTH AVG

MFRs AND SCHEDULES SPONSORED AND CO-SPONSORED BY KIM OUSDAHL

	Period	TITLE
FPL'S 2011 SUBSEQUENT YEAR ADJUSTMENT SCHEDULES SPONSORED OR CO-SPONSORED:		
A-1	FPL's 2011 Subsequent Year Adjustment	FPL's 2011 SUBSEQUENT YEAR ADJUSTMENT REVENUE REQUIREMENTS AND RATES OF RETURN CALCULATIONS
B-1	FPL's 2011 Subsequent Year Adjustment	ADJUSTED RATE BASE
B-2	FPL's 2011 Subsequent Year Adjustment	RATE BASE ADJUSTMENTS
B-6	FPL's 2011 Subsequent Year Adjustment	JURISDICTIONAL SEPARATION FACTORS – RATE BASE
B-15	FPL's 2011 Subsequent Year Adjustment	PROPERTY HELD FOR FUTURE USE – 13 MONTH AVG
B-17	FPL's 2011 Subsequent Year Adjustment	WORKING CAPITAL – 13 MONTH AVG
B-19	FPL's 2011 Subsequent Year Adjustment	MISCELLANEOUS DEFERRED DEBITS
B-20	FPL's 2011 Subsequent Year Adjustment	OTHER DEFERRED CREDITS
B-22	FPL's 2011 Subsequent Year Adjustment	TOTAL ACCUMULATED DEFERRED INCOME TAXES
B-23	FPL's 2011 Subsequent Year Adjustment	INVESTMENT TAX CREDITS – ANNUAL ANALYSIS
B-25	FPL's 2011 Subsequent Year Adjustment	ACCOUNTING POLICY CHANGES AFFECTING RATE BASE
C-1	FPL's 2011 Subsequent Year Adjustment	ADJUSTED JURISDICTIONAL NET OPERATING INCOME
C-2	FPL's 2011 Subsequent Year Adjustment	NET OPERATING INCOME ADJUSTMENTS
C-3	FPL's 2011 Subsequent Year Adjustment	JURISDICTIONAL NET OPERATING INCOME ADJUSTMENTS
C-4	FPL's 2011 Subsequent Year Adjustment	JURISDICTIONAL SEPARATION FACTORS – NET OPERATING INCOME
C-6	FPL's 2011 Subsequent Year Adjustment	BUDGETED VERSUS ACTUAL OPERATING REVENUES AND EXPENSES
C-7	FPL's 2011 Subsequent Year Adjustment	OPERATION AND MAINTENANCE EXPENSES

MFRs AND SCHEDULES SPONSORED AND CO-SPONSORED BY KIM OUSDAHL

MFR #	Period	TITLE
JOINT OR CO-SPONSORSHIP:		
C-8	FPL's 2011 Subsequent Year Adjustment	DETAIL OF CHANGES IN EXPENSES
C-10	FPL's 2011 Subsequent Year Adjustment	DETAIL OF RATE CASE EXPENSES FOR OUTSIDE CONSULTANTS
C-12	FPL's 2011 Subsequent Year Adjustment	ADMINISTRATIVE EXPENSES
C-17	FPL's 2011 Subsequent Year Adjustment	PENSION COST
C-18	FPL's 2011 Subsequent Year Adjustment	LOBBYING EXPENSES, OTHER POLITICAL EXPENSES AND CIVIC/CHARITABLE CONTRIBUTIONS
C-22	FPL's 2011 Subsequent Year Adjustment	STATE AND FEDERAL INCOME TAX CALCULATION
C-23	FPL's 2011 Subsequent Year Adjustment	INTEREST IN TAX EXPENSE CALCULATION
C-24	FPL's 2011 Subsequent Year Adjustment	PARENT(S) DEBT INFORMATION
C-25	FPL's 2011 Subsequent Year Adjustment	DEFERRED TAX ADJUSTMENT
C-27	FPL's 2011 Subsequent Year Adjustment	CONSOLIDATED TAX INFORMATION
C-29	FPL's 2011 Subsequent Year Adjustment	GAINS AND LOSSES ON DISPOSITION OF PLANT AND PROPERTY
C-30	FPL's 2011 Subsequent Year Adjustment	TRANSACTIONS WITH AFFILIATED COMPANIES
C-31	FPL's 2011 Subsequent Year Adjustment	AFFILIATED COMPANY RELATIONSHIPS
C-32	FPL's 2011 Subsequent Year Adjustment	NON-UTILITY OPERATIONS UTILIZING UTILITY ASSETS
C-33	FPL's 2011 Subsequent Year Adjustment	PERFORMANCE INDICES
C-36	FPL's 2011 Subsequent Year Adjustment	NON-FUEL OPERATION AND MAINTENANCE EXPENSE COMPARED TO CPI
C-37	FPL's 2011 Subsequent Year Adjustment	O&M BENCHMARK COMPARISON BY FUNCTION
C-38	FPL's 2011 Subsequent Year Adjustment	O&M ADJUSTMENTS BY FUNCTION
C-41	FPL's 2011 Subsequent Year Adjustment	O&M BENCHMARK VARIANCE BY FUNCTION

MFRs AND SCHEDULES SPONSORED AND CO-SPONSORED BY KIM OUSDAHL

	Period	TITLE
FPL'S 2011 SUBSEQUENT YEAR ADJUSTMENT SCHEDULES SPONSORED OR CO-SPONSORED:		
C-42	FPL's 2011 Subsequent Year Adjustment	HEDGING COSTS
C-43	FPL's 2011 Subsequent Year Adjustment	SECURITY COSTS
C-44	FPL's 2011 Subsequent Year Adjustment	REVENUE EXPANSION FACTOR
D-1a	FPL's 2011 Subsequent Year Adjustment	COST OF CAPITAL – 13 MONTH AVG
D-1b	FPL's 2011 Subsequent Year Adjustment	COST OF CAPITAL – ADJUSTMENTS
D-4b	FPL's 2011 Subsequent Year Adjustment	REACQUIRED BONDS
F-5	FPL's 2011 Subsequent Year Adjustment	FORECASTING MODELS
F-8	FPL's 2011 Subsequent Year Adjustment	ASSUMPTIONS

	Period	TITLE
2009 SUPPLEMENTAL MFR SCHEDULES SPONSORED OR CO-SPONSORED:		
B-04	2009 Supplemental MFR Schedule	Two Year Historical Balance Sheet
B-06	2009 Supplemental MFR Schedule	Jurisdictional Separation Factors - Rate Base
B-19	2009 Supplemental MFR Schedule	Miscellaneous Deferred Debits
B-20	2009 Supplemental MFR Schedule	Other Deferred Credits
C-04	2009 Supplemental MFR Schedule	Jurisdictional Separation Factors – NOI
C-09	2009 Supplemental MFR Schedule	Five Year Analysis - Change In Cost
C-10	2009 Supplemental MFR Schedule	Detail Of Rate Case Expenses For Outside Consultants
C-12	2009 Supplemental MFR Schedule	Administrative Expenses
C-17	2009 Supplemental MFR Schedule	Pension Cost
C-18	2009 Supplemental MFR Schedule	Lobbying Expenses, Other Political Expenses And Civic/Charitable Contributions
C-30	2009 Supplemental MFR Schedule	Transactions With Affiliated Companies
C-31	2009 Supplemental MFR Schedule	Affiliated Company Relationships

MFRs AND SCHEDULES SPONSORED AND CO-SPONSORED BY KIM OUSDAHL

	Period	TITLE
2009 SUPPLEMENTAL MFR SCHEDULES SPONSORED OR CO-SPONSORED:		
C-37	2009 Supplemental MFR Schedule	O&M Benchmark Comparison By Function
C-38	2009 Supplemental MFR Schedule	O&M Adjustments By Function
C-39	2009 Supplemental MFR Schedule	Benchmark Year Recoverable O&M Expenses By Function
C-41	2009 Supplemental MFR Schedule	O&M Benchmark Variance By Function
C-44	2009 Supplemental MFR Schedule	Revenue Expansion Factor
F-01	2009 Supplemental MFR Schedule	Annual And Quarterly Report To Shareholders
F-02	2009 Supplemental MFR Schedule	SEC Reports
F-05	2009 Supplemental MFR Schedule	Forecasting Models
F-08	2009 Supplemental MFR Schedule	Assumptions

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

EXPLANATION: PROVIDE THE CALCULATION OF THE REQUESTED FULL REVENUE REQUIREMENTS INCREASE

TYPE OF DATA SHOWN:
X PROJECTED TEST YEAR ENDED 12/31/10
___ PRIOR YEAR ENDED 12/31/09
___ HISTORICAL TEST YEAR ENDED 12/31/08
___ PROJ. SUBSEQUENT YR ENDED 12/31/11

DOCKET NO. 080677-EI

WITNESS: Kim Ousdahl, Armando Pimentel

(1) DESCRIPTION	(2) SOURCE	(3) AMOUNT ($000)
JURISDICTIONAL ADJUSTED RATE BASE	SCHEDULE B-1	$ 17,063,586
RATE OF RETURN ON RATE BASE REQUESTED	SCHEDULE D-1A	x 8.00%
JURISDICTIONAL NET OPERATING INCOME REQUESTED	LINE 2 X LINE 4	$ 1,364,748
JURISDICTIONAL ADJUSTED NET OPERATING INCOME	SCHEDULE C-1	725,883
NET OPERATING INCOME DEFICIENCY (EXCESS)	LINE 6 - LINE 8	$ 638,865
EARNED RATE OF RETURN	LINE 8 / LINE 2	4.25%
NET OPERATING INCOME MULTIPLIER	SCHEDULE C-44	x 1.633420
REVENUE INCREASE (DECREASE) REQUESTED	LINE 10 X LINE 14	$ 1,043,535

NOTE 1: TOTALS MAY NOT ADD DUE TO ROUNDING.
NOTE 2: TOTAL REQUESTED INCREASE, EXCLUDING THE EFFECT OF PROPOSED COMPANY ADJUSTMENTS RELATED TO COST RECOVERY CLAUSES SHOWN ON MFR C-2, IS $1,121.4 MILLION.

SUPPORTING SCHEDULES: B-1, C-1, D-1a, C-44

RECAP SCHEDULES:

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 118
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Kim Ousdahl (KO-2)
DATE 09/04/09

Docket No. 080677-EI
MFR A-1 for the 2010 Test Year
Exhibit KO-2, Page 1 of 1

2010 Test Year

MFR #	MFR Description	Comment(s)
A-1	Full Revenue Requirements Increase Requested	Derivation and calculation of our full revenue requirement increase requested of $1.044 Billion and resulting jurisdictional rate of return at December 31, 2010
B-1	Adjusted Rate Base	Projected December 31, 2010 thirteen month average jurisdictional adjusted rate base of $17.1 Billion
B-2	Rate Base Adjustments	Includes those necessary, in the opinion of the company, to fairly present rate base and working capital
B-17	Working Capital - 13 Month Average	Adjusted working capital calculation using the balance sheet approach approved by the FPSC (adjustments are explained on MFR B-2)
C-1	Adjusted Jurisdictional Net Operating Income	Projected adjusted net operating income of $726 Million for the year ended December 31, 2010
C-2	Net Operating Income Adjustments	Explanations are on MFR C-3. Includes details of net operating income adjustments on MFR C-1.
C-3	Jurisdictional Net Operating Income Adjustments	Explanations of net operating income adjustments found on MFR C-2
C-44	Revenue Expansion Factor	Calculation of the factor used for the 2010 revenue requirement calculation. The factor as of December 31, 2010 is 1.63342.
D-1a	Cost of Capital - 13 Month Average	Includes Jurisdictional Capital Structure and Required Rate of Return by Class of Capital. The overall rate of return and requested ROE as of December 31, 2010 is 8.0% and 12.5%, respectively.
D-1b	Cost of Capital - Adjustments	Includes Details for Cost of Capital Adjustments listed on MFR D-1A

2011 Subsequent Year Adjustment Schedules

MFR #	MFR Description	Comment(s)
A-1	Full Revenue Requirements Increase Requested	Derivation and calculation of our full revenue requirement increase requested of $247.4 Million and resulting jurisdictional rate of return at December 31, 2011
B-1	Adjusted Rate Base	Projected December 31, 2011 thirteen month average jurisdictional adjusted rate base of $17.9 Billion
B-2	Rate Base Adjustments	Includes those necessary, in the opinion of the company, to fairly present rate base and working capital
B-17	Working Capital - 13 Month Average	Adjusted working capital calculation using the balance sheet approach approved by the FPSC (adjustments are explained on MFR B-2)
C-1	Adjusted Jurisdictional Net Operating Income	Projected adjusted net operating income of $662.8 Million for the year ended December 31, 2011
C-2	Net Operating Income Adjustments	Explanations are on MFR C-3. Includes details of net operating income adjustments on MFR C-1.
C-3	Jurisdictional Net Operating Income Adjustments	Explanations of net operating income adjustments found on MFR C-2
C-44	Revenue Expansion Factor	Calculation of the factor used for the 2011 revenue requirement calculation. The factor as of December 31, 2011 is 1.63256.
D-1a	Cost of Capital - 13 Month Average	Includes Jurisdictional Capital Structure and Required Rate of Return by Class of Capital. The overall rate of return and requested ROE as of December 31, 2011 is 8.2% and 12.5%, respectively.
D-1b	Cost of Capital - Adjustments	Includes Details for Cost of Capital Adjustments listed on MFR D-1A

Docket No. 080677-EI
2010 and 2011 ROE Calculation
Without Rate Relief
Exhibit KO-4, Page 1 of 1

2010 AND 2011 RETURN ON EQUITY CALCULATION
WITHOUT RATE RELIEF

Line No.		MFR Reference	2010	2011 (A)	2011 (B)
1	Adjusted Jurisdictional Net Operating Income	C-1	$ 725,883	$ 662,776	$ 1,311,376
2	Adjusted Jurisdictional Rate Base	B-1	17,063,586	17,880,402	17,880,402
3	**Estimated Earned Rate of Return (Line 1 / Line 2)**		4.25%	3.71%	7.33%
4					
5	Adjusted Jurisdictional Non-Equity Component of Weighted Average Cost of Capital	D-1a	2.01%	2.21%	2.21%
6	**Earnings Available for Common (Lines 3 - 5)**		2.25%	1.50%	5.13%
7					
8	Adjusted Jurisdictional Common Equity Ratio	D-1a	47.93%	47.80%	47.80%
9					
10	**Jurisdictional Return on Common Equity (Line 6 / Line 8)**		4.69%	3.14%	10.73%

Notes:
(A) Calculation assumes FPL's base rate increase for 2010 is not granted.
(B) Calculation assumes FPL's base rate increase for 2010 is granted.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 120
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Kim Ousdahl (KO-4)
DATE 09/04/09

FULL REVENUE REQUIREMENTS INCREASE REQUESTED

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO. 080677-EI

EXPLANATION: PROVIDE THE CALCULATION OF THE REQUESTED FULL REVENUE REQUIREMENTS INCREASE

TYPE OF DATA SHOWN:
___ PROJECTED TEST YEAR ENDED 12/31/10
___ PRIOR YEAR ENDED 12/31/09
___ HISTORICAL YEAR ENDED 12/31/08
X PROJ. SUBSEQUENT YR ENDED 12/31/11

WITNESS: Kim Ousdahl, Armando Pimentel

LINE NO.	(1) DESCRIPTION	(2) SOURCE	(3) AMOUNT
1			
2	JURISDICTIONAL ADJUSTED RATE BASE	SCHEDULE B-1	$ 17,880,402
3			
4	RATE OF RETURN ON RATE BASE REQUESTED	SCHEDULE D-1A	x 8.18%
5			
6	JURISDICTIONAL NET OPERATING INCOME REQUESTED	LINE 2 X LINE 4	$ 1,462,895
7			
8	JURISDICTIONAL ADJUSTED NET OPERATING INCOME	SCHEDULE C-1	662,776
9			
10	NET OPERATING INCOME DEFICIENCY (EXCESS)	LINE 6 - LINE 8	$ 800,119
11			
12	EARNED RATE OF RETURN	LINE 8 / LINE 2	3.71%
13			
14	NET OPERATING INCOME MULTIPLIER	SCHEDULE C-44	x 1.632560
15			
16	REVENUE REQUIREMENT (NO 2010 RATE RELIEF)	LINE 10 X LINE 14	$ 1,306,243
17			
18	2010 REVENUE INCREASE REQUESTED	SEE NOTE 1	$ 1,058,876
19			
20	RATE INCREASE REQUESTED (AFTER FULL 2010 RATE INCREASE)	LINE 16 - LINE 18	$ 247,367
21			
22			
23			
24	NOTE 1: 2010 REVENUE INCREASE REQUESTED ON TEST YEAR MFR A-1, $1,043,535,000 ADJUSTED FOR 2011 SALES GROWTH.		
25			
26			
27			
28	NOTE: TOTALS MAY NOT ADD DUE TO ROUNDING.		
29			

SUPPORTING SCHEDULES: B-1, C-1, D-1a, C-44

RECAP SCHEDULES:

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 121
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Kim Ousdahl (KO-5)
DATE 09/04/09

Docket No. 080677-EI
MFR A-1 for the 2011 Subsequent Year
Exhibit KO-5, Page 1 of 1

Docket No. 080677-EI
Base Rate Recovery Formula
for Nuclear Uprates
Exhibit KO-6, Page 1 of 1

BASE RATE RECOVERY FORMULA
FOR
ST. LUCIE AND TURKEY POINT NUCLEAR UPRATES

Line No.		Formula		Base Rate Rev Req Calc Example (B)
1	Plant-in-Service	Insert Value	$	5,000,000
2	Accumulated Depreciation	(1.2% of Line 1) / 2		(30,000)
3	**Net Plant-in-Service (C)**	**Lines 1 + 2**	**$**	**4,970,000**
4				
5	Cost of Capital (D)	11.7765%		11.7765%
6	**Return on Investment**	**Lines 3 * 5**	**$**	**585,292**
7				
8	Operations & Maintenance Expenses	Insert Value	$	-
9	Property Insurance Expense (A)	0.37% of Line 1		18,500
10	Depreciation Expense (A)	1.2% of Line 1		60,000
11	Property Taxes (A)	2.0% of Line 1		100,000
12	**Total Expenses**	**Sum of Lines 8 - 11**	**$**	**178,500**
13				
14	**Total System Revenue Requirements**	**Lines 6 + 12**	**$**	**763,792**
15	Separation Factor (E)	98.8182%		98.8182%
16	**Total Jurisdictional Revenue Requirements (F)**	**Lines 14 * 15**	**$**	**754,766**

Notes:

(A) Percentages in formula are same as what was used to estimate expenses for St. Lucie Unit 2 nuclear uprate forecast in this filing. The following percentages would need to be changed if base rate recovery is for a plant other than St. Lucie 2:
- St. Lucie Unit 1 - Depreciation Rate 1.6%
- Turkey Point Unit 3 - Property Tax Rate 1.8%
- Turkey Point Unit 4 - Depreciation Rate 1.4%, Property Tax Rate 1.8%

(B) Base rate revenue requirement calculation example if $5 million in capital costs at St. Lucie Unit 2 are determined non-recoverable through Nuclear Cost Recovery by the FPSC.

(C) Based on a 13-month average.

(D) Represents pre-tax cost of capital used for the 2010 Test Year in this filing. The rate applicable to 2011 is 11.9759%.

(E) Represents the nuclear separation factor used for the 2010 Test Year in this filing. The factor applicable to 2011 is 98.8108%.

(F) Does not take into account gross up for bad debt or regulatory assessment fee.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 122
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Kim Ousdahl (KO-6)
DATE 09/04/09

Docket No. 080677-EI
Depreciation Expense Reconciliation
from Forecast to Proposed Amount
Exhibit KO-7, Page 1 of 2

DEPRECIATION RECONCILIATION FROM FPL'S 2010 FORECAST TO PROPOSED DEPRECIATION EXPENSE
($000)

Line No.	Function	2010 Forecast (1)	2010 Depreciation Expense Related to Clauses (2)	Subtotal (1) + (2) = (3)	2010 Calculated Expense Using Proposed Rates (4)	2010 Expense From Capital Recovery Schedules (5)	2010 Total Expense (4) + (5) = (6)	2010 Company Adjustment (6) - (3) = (7)
1	INTANGIBLE	$ 26,011	$ (1,142)	$ 24,869	$ 22,067	$ -	$ 22,067	$ (2,802)
2								
3	STEAM	82,402	(16,140)	66,262	88,945	11,227	100,172	33,911
4								
5	NUCLEAR	66,936	(1,281)	65,655	103,428	42,059	145,487	79,831
6								
7	OTHER PRODUCTION	296,012	(7,895)	288,117	284,302	-	284,302	(3,815)
8								
9	TRANSMISSION	94,420	(284)	94,135	97,622	-	97,622	3,486
10								
11	DISTRIBUTION	389,015	(7,167)	381,848	357,266	25,270	382,536	688
12								
13	GENERAL	48,188	(1,647)	46,542	30,353	-	30,353	(16,188)
14								
15	TOTAL	$ 1,002,984	$ (35,555)	$ 967,429	$ 983,983	$ 78,556	$ 1,062,539	$ 95,111
		(A)	(B)		(C)	(D)	(E)	(F)

Notes:

(A) Excludes amounts related to asset retirement obligations, acquisition adjustment, dismantlement, and FPL-NED, which are included in the total amount forecasted for depreciation expense.
(B) Includes forecasted depreciation related to nuclear uprates since it is recovered through the nuclear cost recovery mechanism.
(C) Calculated amounts are based on FPL's proposed depreciation rates included in its 2009 depreciation study.
The amounts also include expense related to amortizable property.
(D) Capital Recovery Schedules are for the recovery of the net book cost over a four year period:
Steam: Cape Canaveral and Riviera Plant modernizations (recovery of net book cost of existing facilities)
Nuclear: St. Lucie and Turkey Point Plant uprates (recovery of net book cost of retirements and associated removal costs)
Distribution: Automated Meter Infrastructure (recovery of net book cost of meters being replaced and associated removal costs)
(E) Total expense is based on FPL's proposed depreciation rates and capital recovery schedules included in its 2009 depreciation study. The amounts also include expense related to amortizable property.
(F) Included in depreciation company adjustment shown on MFR C-3.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 123
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Kim Ousdahl (KO-7)
DATE 09/04/09

Docket No. 080677-EI
Depreciation Expense Reconciliation
from Forecast to Proposed Amount
Exhibit KO-7, Page 2 of 2

DEPRECIATION RECONCILIATION FROM FPL'S 2011 FORECAST TO PROPOSED DEPRECIATION EXPENSE
($000)

Line No.	Function	2011 Forecast (1)	2011 Depreciation Expense Related to Clauses (2)	Subtotal (1) + (2) = (3)	2011 Calculated Expense Using Proposed Rates (4)	2011 Expense From Capital Recovery Schedules (5)	2011 Total Expense (4) + (5) = (6)	2011 Company Adjustment (6) - (3) = (7)
1	INTANGIBLE	$ 37,739	$ (1,527)	$ 36,211	$ 31,953	$ -	$ 31,953	$ (4,258)
2								
3	STEAM	85,355	(17,993)	67,362	90,815	11,227	102,042	34,680
4								
5	NUCLEAR	75,687	(7,072)	68,616	114,820	42,059	156,879	88,264
6								
7	OTHER PRODUCTION	323,792	(24,033)	299,760	292,014	-	292,014	(7,745)
8								
9	TRANSMISSION	98,152	(564)	97,587	101,219	-	101,219	3,631
10								
11	DISTRIBUTION	412,201	(8,539)	403,662	383,153	25,270	408,423	4,761
12								
13	GENERAL	56,189	(3,418)	52,771	34,629	-	34,629	(18,142)
14								
15	TOTAL	$ 1,089,115	$ (63,146)	$ 1,025,970	$ 1,048,603	$ 78,556	$ 1,127,159	$ 101,191
		(A)	(B)		(C)	(D)	(E)	(F)

Notes:
(A) Excludes amounts related to asset retirement obligations, acquisition adjustment, dismantlement, FPL-NED, and West County Unit 3, which amount forecasted for depreciation expense.
(B) Includes forecasted depreciation related to nuclear uprates since it is recovered through the nuclear cost recovery mechanism.
(C) Calculated amounts are based on FPL's proposed depreciation rates included in its 2009 depreciation study. The amounts also include expense related to amortizable property.
(D) Capital Recovery Schedules are for the recovery of the net book cost over a four year period:
Steam: Cape Canaveral and Riviera Plant modernizations (recovery of net book cost of existing facilities)
Nuclear: St. Lucie and Turkey Point Plant uprates (recovery of net book cost of retirements and associated removal costs)
Distribution: Automated Meter Infrastructure (recovery of net book cost of meters being replaced and associated removal costs)
(E) Total expense is based on FPL's proposed depreciation rates and capital recovery schedules included in its 2009 depreciation study. The amounts also include expense related to amortizable property.
(F) Included in depreciation company adjustment shown on MFR C-3.

Florida Power & Light Company

Fossil Dismantlement Studies

Cape Canaveral
Cutler
DeSoto Solar
Fort Lauderdale
Fort Myers
Manatee
Martin
Port Everglades
Putnam
Riviera
Sanford
Scherer
St Johns River
Turkey Point
St. Lucie Wind
West County

Note: Filed on March 17, 2009, due to Commission timing requirements for this study and not duplicated separately due to volume.

2009 Filing

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COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Kim Ousdahl (KO-8)
DATE 09/04/09

Cost Measurement & Allocation Department
Cost Accounting Manual
Updated December 2008

BACKGROUND

Market Rate Disclosure

Florida Power & Light Company (FPL) supports affiliate operations through direct project activities and shared administrative functions. Direct activities are charged to affiliates through specific work orders. Shared administrative functions are allocated through five (5) management fees.

All services provided to affiliates, either direct or allocated, are transferred at fully loaded rates. Payroll is transferred by using the employee job role reference point plus adders, which covers benefits, and administrative costs; thus fully loaded rates reflect market rates. Therefore, FPL believes that the rates it charges Affiliates for services it provides are in compliance with its policy to charge at the higher of cost or market.

Description of the five (5) management fees:

1. Affiliate Management Fee (AMF) - FPL Corporate Staff infrastructure that benefits Affiliates are transferred at fully loaded rates. This management fee is based on a cost pool of shared services, which is allocated based on specific drivers (where available), or the Massachusetts formula, which is the weighted average of Revenue, Payroll, and average Property, Plant, and Equipment. The Fee is billed monthly based on budget, and trued-up to year-end actuals during the last quarter of the current year and then again during the first quarter of the subsequent year. The fee may be revised during the year to reflect significant changes such as merger and acquisition activities. Examples of services provided include:

- Payroll Processing
- Tax Accounting
- Accounting / Auditing
- Environmental
- Information Management
- Human Resources
- Corporate Communications
- Finance / Treasury
- General Counsel

2. FPL's Power Generation Division (PGD - Direct Charge Method) - provides fleet team common and direct plant specific support to FPL Energy; Inc. (FPLE). Fully loaded costs are charged to the Affiliate based on budgeted dollars with a year-end true-up based on actual accumulated dollars via specific work-orders. The fee may be revised during the year to reflect significant changes such as level of service, and/or merger and acquisition activities.

3. Energy Marketing & Trading Business Unit (EMT – Specific Allocations) - provides Back-Office (Risk Management and Systems) support. Costs are allocated to the Affiliate based on time studies or specific analysis by function. Fully loaded costs are also charged to the Affiliate based on budgeted dollars with a periodic true-up to actual dollars, including one at year-end. The fee may be revised during the year to reflect significant changes such as level of service, and / or merger and acquisition activities. In addition, the Affiliate is charged a facilities usage fee.

4. Nuclear Division (NUC – Generating Units) – provides nuclear operations, fuels, management team and assurance support to FPLE nuclear plants. Fully loaded costs are allocated to the Affiliate based on number of generating units and budgeted dollars with periodic true-up to actual dollars, including one at year-end.

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The fee may be revised during the year to reflect significant changes such as level of service, and / or merger and acquisition activities.

5. Information Management Nuclear Support (IMNUC – Systems or Generating Units) – provides Passport system support, IM management team, data services and infrastructure support to FPLE nuclear plants. Fully loaded costs are allocated to the Affiliate based on either number of Passport systems or number of generating units and budgeted dollars with periodic true-up to actual dollars, including one at year-end. The fee may be revised during the year to reflect significant changes such as level of service, and / or merger and acquisition activities.

An Introduction

This Cost Allocation Manual was prepared for the use of FPL Group's regulated utility subsidiary, FPL, to document cost allocation policies and practices, and to provide guidelines to employees regarding the use of those policies for both Inter-Company and Intra-Utility transactions.

Outside vendors doing work for the affiliates should be instructed to bill affiliates directly for work performed and not process payments through FPL. This eliminates duplicate invoice processing and provides Affiliates with a clear approval of work performed.

Whenever practical, FPL employees should direct charge for services to the benefiting Affiliate. This manual describes processes to direct charge those costs, as well as the allocation processes used when direct charging is not practical.

Cost Accounting Concepts

This manual is based on the premise that all costs will be apportioned between regulated and non-regulated activities. Apportionment is defined as any distribution of costs to the benefiting regulated or non-regulated activities. Additionally, corporate center costs remaining in FPL (regulated), which provide a direct benefit to the operating business units, will be apportioned to the benefiting operating business units. Consistent with the foregoing premise and definition, costs are apportioned based on three cost characteristics:

- **Direct** - Costs of resources used exclusively for the provision of services that are readily identifiable to an activity. An example of Inter-Company direct costs would be the salary of an engineer working on a non-regulated Affiliate's power plant. Direct is also used to indicate work done within FPL (regulated) directly benefiting a Business Unit other than the provider. An example of Intra-FPL direct costs (regulated) would be Human Resources charging the operating Business Units for specific recruiting activities.

- **Assigned** – Costs of resources used jointly in the provision of both regulated and non-regulated activities that are apportioned using direct measures of cost causation. The square footage cost of office space used by non-regulated activities would be an example of assignable costs.

- **Unattributable (Management Fee)** – Cost of resources shared by both regulated and non-regulated activities for which no causal relationship exists. These costs are accumulated and allocated to both regulated and non-regulated activities through the use of the AMF for Inter-Company transactions. The costs associated with FPL Group's board of directors is an example of unattributable costs allocated using the Affiliate Management Fee. (See Affiliate Management Fee section for more details on unattributable charges.)

Inter-Company Transactions - Between Regulated and Non-Regulated Entities

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This manual is designed to document the processes used to apportion costs between regulated and non-regulated activities. The prevailing premise is that resources shared between regulated and non-regulated activities should not result in subsidization by either entity. This manual describes the standard services provided between regulated and non-regulated entities, FPL's (regulated) inter-company process for charging direct and indirect costs, AMF, and other apportionment methods. The costing concepts and principles described herein are applied consistently to all subsidiaries.

Purchase Orders

When Affiliates procure goods from common vendors of FPL (regulated), they should do so directly under separate Affiliate purchase orders. This ensures invoicing and product delivery will be processed directly to the Affiliate, and the Affiliate will not be billed for FPL's (regulated) loading costs. It also ensures that the contract terms (warranties and liabilities) of the purchase order(s) are placed with the Affiliate, not with FPL (regulated).

Transfer of Assets

When an asset used in FPL's regulated operations is transferred to a non-regulated Affiliate, FPL will charge the Affiliate the greater of market price or net book value. Except, FPL may charge the Affiliate either the market price or net book value if documentation is maintained to support and justify that such a transaction benefits regulated operations. When an asset that is to be used in FPL's regulated operations is transferred from a non-regulated Affiliate, the asset must be recorded at the lower of market price or net book value. On certain occasions, FPL may record the asset at either market price or net book value if it maintains documentation to support and justify that such a transaction benefits regulated operations. An independent appraiser must verify the market value of a transferred asset with a net book value greater than $1,000,000.

REGULATORY REPORTING

Diversification Report

In addition to the FERC Form No. 1, Annual Report of Major Electric Utilities, Licenses and Others, the FPSC requires the Utility to file an Annual Diversification Report. This report contains:

- Summary of changes to the corporate structure,
- Updated organizational charts of parent and affiliates,
- Summary of new or amended contracts with affiliates,
- All transactions between regulatory and non-regulatory activities
- Detail reports of all individual transactions over $500,000 between affiliates
- Summary of asset transfers between affiliates,
- Employee transfers between affiliates,
- Analysis of non-tariffed services and products provided by the Utility.

FERC Accounting

The Uniform System of Accounts (USOA), as prescribed by the Federal Energy Regulatory Commission (FERC), and adopted by the Florida Public Service Commission (FPSC), is found in the Code of Federal Regulations, Title 18, Subchapter C, Part 101 states the following:

- Inter-company transactions are to be recorded in account 146.XXX (See sub account listing at the <u>ER 99 Reporting</u> section).
- Intra-Utility direct charge transactions are to be recorded in the appropriate account(s) within the operational function receiving the goods or services.

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- Intra-Utility allocations of corporate center costs for business unit financial reporting are to be recorded in the administrative and general (A&G) range of accounts. Administrative and general accounts should contain charges not chargeable directly to a particular operating function.
- Based on the USOA guidelines, functional accounts should be charged for corporate center charges when the work benefits only one business unit. If the work is allocated to several business units for financial reporting purposes, the costs should remain in the A&G range of accounts (920.XXX - 935.XXX).

FPSC Rule

The Florida Public Service Commission has adopted rules concerning cost allocation and affiliate transactions. The purpose of this rule is to establish cost allocation requirements to ensure proper accounting for affiliate transactions and non-regulated utility activities in order for these transactions and activities to not be subsidized by FPL (regulated) customers. This cost allocation manual addresses all processes for compliance under this rule.

SFAS 131

FPL Group and its subsidiaries are subject to the provisions and required disclosures of Statement of Financial Accounting Standards (SFAS) No. 131, Disclosures about Segments of an Enterprise and Related Information. SFAS 131 only requires disclosure for business operations that exceed 10% of the total business operations. FPL Group has three reportable segments, FP&L (regulated operations), FPL Energy (unregulated operations – Independent Power Producer) and Corporate & Other.

INTER-COMPANY BILLING PROCESS

Billings from Affiliates to FPL

Billings from affiliates to FPL are based on the lower of cost or market. When these billings occur, notification must be given to Cost Measurement and Allocation to ensure proper reporting of these transactions as required by FERC and FPSC. The Cost Measurement and Allocation Department records these transactions. If a Business Unit elects to pay such invoices themselves, they are required to forward copies of all transactions to Cost Measurement and Allocation. All inter-company billings through the CARMS account receivable system are reconciled to the general ledger on a monthly basis.

Approval for Affiliate Direct Charges

When working directly for an Affiliate, FPL employees must first obtain approval from the Affiliate and obtain a corresponding ER 99 work order. This applies to both payroll and non-payroll transactions. For payroll transactions the employee must also verify that their payroll location/section is valid for the stated work order. Validation of work orders can be checked through the system (GA30) or by calling IM-Financial Systems at (305) 552-3567. When providing services to a specific Affiliate, the employee is responsible to ensure that the appropriate ER 99 work order is recorded on their time sheet and/or cash vouchers.

Use the following contacts to obtain approval to charge affiliate work orders:

Affiliate	Contact	Phone Number
FPL Energy	Grace Wynter Cathy Gibson	(561) 304-5269 (561) 691-7467
FPL Energy Services	Kenneth Frantz	(305) 552-3239
FPL FiberNet	Lourdes Caballero	(305) 552-2018
FPL Group Capital	Peaches Libkie	(561) 694-4853

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ER 99 Function

FPL uses the Expenditure Requisition (ER) code 99 in the account key structure to designate work orders used exclusively for inter-company billings. A work order is a combination of ER, work order (WO), location and section (Example WO 4300 ER 99 Loc 0009 Sec 21). Each work order has a unique translation to FPL general ledger accounts.
All ER 99 work orders translate to receivable accounts from Affiliates. Below is a list of our current Affiliate receivable accounts:

Affiliate	Account
Alandco	146.400
Duane Arnold	146.430
Fibernet	146.610
FPL Energy, Inc.	146.880
FPL Energy Maine	146.890
FPL Energy – Seabrook	146.856
FPL Energy Services (NE Gas)	146.905
FPL Energy Services, Inc.	146.906
FPL Group	146.300
FPL Group Capital	146.800
FPL Group International	146.370
FPL New England Division	146.320
FPL Readi-Power LLC	146.612
FPLE Power Marketing	146.860
FPLE Project Management	146.870
Palms Insurance	146.310
Point Beach	146.440
N. American Power Systems	146.380
Seabrook Station	146.855

Charges to the ER 99 work orders are accumulated each month and billed by the 15th of the following month. Included in these charges are payroll charges which are billed based on standard rates by classification (standard rates are described in the next section.) All payroll related overhead charges are included in the standard rates. Also included in the billable charges are non-payroll charges that do not contain any loadings. To facilitate proper supporting documentation for the invoices, Cost Measurement and Allocation maintains special reporting from the ER 99 transactions. These reports provide the detail transactions for each bill and are broken down by payroll and non-payroll transactions. These reports contain the description fields for the account key structure that identifies the charging location, employee name, and EAC description.

For payroll transactions, the ER 99 process cross-references the last five digits of the employee's social security number and the last five digits of the last name to the employee's job classification. The job classification is then matched to the standard billing rate table to obtain the hourly-billing rate. Cost Measurement & Allocation reviews all transactions to ensure the employee name is listed on the billing support documentation. Each month some payroll transactions are not matched to standard rates due to transfers, new employee, etc. These transactions appear on the Payroll Exception Report, which are then manually researched, and then the transactions are billed. Cost Measurement and Allocation ensures employee names are included on all Payroll Exception Reports transactions as

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well. Affiliates are required to pay all invoices within 15 days of invoice date. Any corrections required based on the review by the Affiliate Project Managers are included in the subsequent month's billing.

GA 30 Access Instructions

Step	Action
1	Logon to PCICS
2	Type GA30, hit <Enter>
3	Select BUCS option 4 <Enter>. There are 8 options on this screen
4	To determine if your location section is valid for ER 99 select Option 8 Work Order Translation <Enter>
5	Type the Work Order, ER 99, your location section <Enter>
6	If your location section is valid it will show the account translation. If your location section is not valid, it will skip to the next valid location.

Long Term Assignment Rates

When FPL employees are used exclusively for Affiliate activities for extended periods of time, they should not be charged out at the standard rates but at a reduced Long-Term Loading Rate. This is due to two factors. First, their non-productive time (sick, vacation, holiday) is already included in the salary being allocated since it is expected that a full year's salary is allocated. If their time were also loaded for non-productive time, the Affiliate would be receiving a duplicate charge. Secondly, the Affiliate will be providing the necessary A&G support, such as supervision, office equipment, supplies, etc. Therefore, A&G expenses should not be included in the loading rate.

The 2008 Long-term Loading Rate is 15.19%, which includes Taxes & Insurance of 7.83% and Pension & Welfare of 7.36%. To qualify for reduced loading, the employee must reasonably expect to charge their time to ER 99 work orders for one full year, and be physically located at the Affiliate. If an employee's charges during the year fall below 75% they must be removed from the Long-Term loading rate.

Employees meeting the above requirements should forward their social security number, payroll location, business unit name and immediate supervisor's name to the Cost Measurement & Allocation department. The social security number will then be entered into the ER 99 billing program to facilitate this exception handling. The employee is responsible to ensure that their time is charged to the ER 99 work orders including all non-productive time such as vacation, holiday, sick, jury duty, etc. It is recommended that employees set up their Fixed Distribution with ER 99 work orders to accomplish this. Since the Long-Term rates are based on actual payroll, any bonus and/or incentives paid during the year will also be passed on to the Affiliate. Additionally, all Affiliate non-payroll related expenses should be charged at 100%.

Standard Hourly Payroll Rates

The standard hourly rates are determined by taking each job classification's Market Reference Point (MRP), applying the common cost loading rate, and dividing by 2080 hours. The common cost rate loads payroll for benefits and A&G costs related to the employee.

Loadings, computed annually by the Cost Measurement and Allocation section of Regulatory Accounting, are incorporated into the 2008 Standard Billing Rates (commonly referred to as the "Short Term Rate"):

Loading	Feb 2007 – Rate	Feb 2008 – Rate
Non-Productive Payroll	21.47%	21.74%

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Administrative and General Payroll *	13.84%	14.26%
Taxes and Insurance**	11.24%	10.64%
Pension & Welfare**	11.28%	10.02%
Administrative and General Expense *	15.02%	13.46%
Total	**72.86%**	**70.13%**
Note: Rates above are compounded, except Non-Productive Payroll. * Applied to the total of Productive and Non-Productive Payroll ** Applied to the total of Productive, Non-Productive and A & G Payroll		

Market Reference Points

FPL employees working for the subsidiaries are billed out at their job role's Market Reference Point (MRP) which began back in June 2005. There are approximately 224 MRP's in existence and when an employee charges an ER 99 work order, the system automatically performs a table lookup based on their last 5 digits of their social security number and first 5 digits of their last name to locate the employee's job role and apply the appropriate MRP and loader. It should be noted that the MRP in the billing rate column on the Affiliate billing ERTRAN reports is unloaded; however, the dollars under the "Amount" column are loaded.

MANAGEMENT FEES

Affiliate Management Fee

When FPL Group started diversifying into non-regulated activities, FPL developed an Inter-Company accounting policy to address the transfer of goods and services between the regulated (FPL) and non-regulated (Affiliate) activities. This process uses FPL's ER 99 work orders to capture charges directly benefiting Affiliates. As the non-regulated activities expanded, a shared service concept called the Affiliate Management Fee was implemented to address Corporate Staff shared services and capital benefiting both FPL and its Affiliates.

Cost Pool - Corporate Shared Services

The Shared Service cost pool is determined annually through an extensive review of shared services and capital provided by FPL's Corporate Staff Departments. The review is performed in conjunction with FPL's budget cycle and identifies products and services within each Budget Activity (BA), along with capital benefiting Affiliates. These budgeted costs and capital are combined to obtain an estimated shared cost pool for the year. For 2008, shared services are estimated at $199 million dollars (see listing of Shared Services included below). These shared costs are allocated to non-regulated Affiliates using specific drivers (where available) or the Massachusetts Formula (see below). These shared cost pools are trued up to actuals in the fourth quarter of the current year and again in the first quarter of the following year. The cost pools will also be trued up to actuals for any merger and acquisition activity.

Allocation - Massachusetts Formula

FPL reviewed options for allocation of the cost pool(s) where there were no specific driver(s) and elected to use the weighted average of Payroll, Revenues and average Gross Property Plant and Equipment. This methodology is named the "Massachusetts Formula" and has been an industry standard in other regulatory areas for years. The forecasted amounts for each of the three components mentioned are collected from FPL and Affiliates and given equal weight. A weighted average is then computed to yield a ratio of regulated and non-regulated activity. The Massachusetts Formula is updated for merger and acquisition activity as needed.

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FPL Group Capital is billed a monthly portion of the annual Affiliate Management Fee. The annual fee amount is determined by identifying the FPL Group executive costs and FPL corporate staff costs that benefit both FPL and Affiliates. Then the appropriate driver percentages (either specific drivers or the Massachusetts Formula) are applied to the respective cost pools. For 2008, the fee is estimated to be approximately $49 million dollars.

Corporate Shared Services and Capital

Below is a list of shared services determined to be beneficial to Affiliates and included in the Affiliate Management Fee. Shared services payroll dollars are loaded with Taxes & Insurance of 7.83% and Pension & Welfare of 7.36% prior to their allocation for 2008.

Allocation - Specific Drivers

The Information Management and Human Resources Corporate Staff group shared costs are allocated to the Affiliates by specific drivers. Other Corporate Services and certain Finance costs also have specific drivers to allocate shared costs to Affiliates.

- **Information Management** (Specific drivers relating to workstations, number of transactions, mainframe time, etc.)
  - Corporate Applications - HR Employee Information System, Procurement, Financial Data Base, Lotus Notes, Storehouse
  - Communications & Technology - Telecommunications (excluding Long Distance) and Fibernet
  - Distributed Systems -Workstation and LAN Support
  - Mainframe Operations - GO and JB Computer Centers
  - PC Services - Helpdesk and Workstation support
  - Amortization and ROI - Shared Capitalized Hardware and Software

- **Human Resources** (Specific drivers relating to FTE's)
  - Employee Relations - Safety Polices, Labor Relations Administration, and other employee related issues
  - Shared Services - Benefits Administration, Help Desk, Payroll, Educational Assistance, Recruiting, Equal Opportunity, Workforce Planning, Drug testing and Group University
  - Benefit Programs

- **Finance** (Specific drivers relating to square footage and capacity)
  - Security – Corporate and shared affiliate facility (JB and GO)
  - Business Unit Executive – Power Generation Division and Nuclear

- **Engineering, Construction and Corporate Services** (Specific drivers relating to FTE's)
  - Cafeteria Operations – Shared Affiliate Cafeteria Operations (JB, GO, LFO, CSE, PTN & PSL)

Allocation - Massachusetts Formula

- **Finance**
  - Executive – Salaries, Expenses, and Benefits
  - Corporate - Accounts Payable, Cash Management and Banking
  - Accounting - Cost Measurement & Allocation, Accounting Research & Financial Reporting
  - Corporate Tax

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- Finance and Trust Fund Investments
- Planning and Analysis
- Corporate Budgeting
- Annual Report
- Security Administration - Facility Security, Data Security
- Aircraft Operations - Fixed costs of Aircraft Operations only (Variable direct charged on a per flight basis)
- Amortization and ROI – Aviation

- **Corporate Communications**
  - Internal Communications - Inside FPL, FPL Today, FYI FAX
  - External Media
  - Executive Presentations
  - Mail Services – Courier and Mail Services (GO, JB, LFO)

- **General Counsel**
  - Shareholder Services
  - Environmental Services - Environmental Audits and Consulting

- **Engineering, Construction and Corporate Services**
  - Integrated Supply Chain – Administration of Corporate Travel and Integrated Supply Chain

- **Internal Auditing Management**

SERVICE FEES – Energy Marketing & Trading (EMT), Power Generation Division (PGD), Nuclear (NUC), and IM Nuclear (IMNUC)

Service fee charges are calculated by the Business Unit (Operating Business Unit or Staff Group) Budget Coordinators or Analysts and represent ongoing services provided or shared among Affiliates. The appropriate Standard Hourly Payroll Rate (see previous section with this title) is applied to payroll charges, and reduced by non-productive time if the payroll dollars are applied at 100%. In general, services provided by EMT include Systems support and Risk Management of the Back Office group and a Facilities Fee for Power Marketing, Inc. space. The Nuclear Fee is support to FPLE nuclear plants and the IM Nuclear fee relates to specific system support for FPLE nuclear plants. The Power Generation Division Fee provides central maintenance and/or technical services to FPLE fossil plants.

EMT Service Fee

The EMT Service Fee uses the annual budget to estimate the level of service to be provided and will true-up to actuals periodically or for year-end no later than January of the following year. There are two parts of this fee: 1. Back-Office, and 2. PMI Facilities Usage. There are two (2) groups within the Back-Office portion of the fee: 1. System Group for computer support, and 2. Risk Management. The Systems Group is allocated by specific drivers (i.e. number of devices), and Risk Management is allocated based on a time-study. The second part of the Fee is the PMI Facility Usage, which is allocated bases upon total head count applied to a developed facility rate. The EMT Service Fee includes the following shared services:

- Wholesale Operations Senior Management - Supervision of physical trading front office operations
- Operations and Administration - Support of EMT systems infrastructure
- Risk Management - Compliance with risk management policies and procedures
- Contracts and Regulatory - Contract execution and regulatory filing requirements

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- Corporate Loadings - Standard Hourly Payroll Rate applied to payroll
- Facilities Usage - Charge for FPLE employees using EMT facilities and equipment

Specific services not included in the Service Fee, which are direct charged to FPLE by EMT are:

- Services to Plants that are not operated by FPL Energy
- Front office trading and analysis

Nuclear Service Fee

The Nuclear Service Fee uses the annual budget to estimate the level of service to be provided and will true-up to actuals periodically or for year-end no later than January of the following year. The fee allocates costs using the number of generating units as the driver. The Nuclear Service Fee includes the following shared services:

- Nuclear Operations Support
- Nuclear Fuels Support
- Nuclear Management Team Support
- Nuclear Engineering Support
- Nuclear Assurance Support

Specific services not included in the Service Fee, which are direct charged to FPLE by Nuclear are:

- Due Diligence
- Construction Projects
- Transition Teams
- Support of FPL Energy Capital Projects
- Outage Support

Information Management Nuclear Service Fee

The Information Management Nuclear Service Fee uses the annual budget to estimate the level of service to be provided and will true-up to actuals periodically or for year-end no later than January of the following year. The fee allocates costs depending on the services provided. Costs for services that support the Passport system are allocated on the number of systems in place. Management and infrastructure services costs are allocated using the number of generating units as the driver. The Information Management Nuclear Service Fee includes the following shared services:

- Passport Support
- IM Management
- Data Services
- IMO Nuclear Lead (Infrastructure Support)

Power Generation Division (PGD) Service Fee

The PGD Service Fee is based on the direct charge methodology (as previously described). Initially, PGD uses budgeted costs for shared activities and an estimate of the services to be provided to FPLE. Actual costs for the services provided are accumulated in specific work orders. These costs are compared to the budgeted costs and trued-up periodically or for year-end no later than January of the following year.

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The PGD Service Fee includes the following shared services:

- Fleet Team Management – Production Assurance, Balance of Plant, Turbine Generator, Steam Generation, Central Maintenance, Electrical and Instrumentation & Controls, Lab Testing, Environmental, Water Management and Reliability
- Information Systems - support of PGD system infrastructure
- Corporate Overheads - Loadings for Payroll, Facilities, Equipment
- Business Planning, Resource Allocation and Administration
- Safety Programs

FACILITY AND EQUIPMENT CHARGES

Cost Measurement and Allocation is responsible for monthly entries through ER 99 work orders to bill the following activities:

Accounting Systems
The Affiliates use FPL's accounting systems on a limited basis for paying and issuing miscellaneous invoices. These systems are the Cash and Accounts Receivable Management (CARMS) and Customer Information System Plus (CIS Plus). The use of these systems is billed on a transactional basis. A cost study is performed by the Cost Measurement and Allocation department to determine the cost to FPL per transaction for these systems. The number of transactions are collected monthly and billed to the Affiliates at those rates.

Furniture and Computers
The Affiliates are billed monthly for office furniture and personal computers on a cost basis. The charges are based on the number of FPL owned equipment utilized by the Affiliates. The 2008 rates are:

Cubicle furniture rental rate	$1,448.00 annually per cubicle
Office furniture rental rate	$ 731.69 annually per office
Workstation computer rental rate	$ 473.23 annually per workstation
Laptop computer rental rate	$ 684.93 annually per laptop

Long Distance Telephone Charges
The Affiliates are billed monthly for their long distance service. This is tracked by telecommunications based on employee long distance IDs. Rates are based on actual contracted rates with the phone companies.

Office Space
Space is available to the Affiliates in FPL buildings only when vacancies exist. The Affiliates are charged for the square feet they occupy based on the higher of cost or a market rate. The market rate study is performed by Corporate Real Estate. Currently, FPL Energy, FPL Energy Services and Fibernet occupy space in FPL buildings, primarily the General Office and the Juno Beach Office.

AVIATION POLICY

FPL aviation equipment is available to FPL and Affiliates employees on a business priority basis. Inter-Company flights are charged back to the Affiliates. Intra-FPL flights are not charged back to the business unit.

Fixed Costs
Fixed costs include salaries, hangar expenses, and maintenance which are included in the Affiliate Management Fee.

Variable Costs

Cost Measurement & Allocation Department
Cost Accounting Manual
Updated December 2008

The variable cost has been determined using an industry standard analysis. The items comprising the variable cost are fuel, fuel additives, landing & parking fees, crew expenses, and small supplies & catering. These costs are charged out on a per flight basis as follows for 2008:

- Helicopter $267.58 per flight hour (1/1/08-6/30/08) and $329.58 (7/1/08 - 12/31/08)
- Airplanes either $2.80 per statutory mile or $2.29 per statutory mile (1/1/08-6/30/08) and either $3.32 or $2.74 (7/1/08-12/31/08), depending on the type of plane used.

DEFINITIONS

Affiliates – Companies that are related to each other due to common ownership or control.

Cost Allocators – The methods or ratios used to apportion costs. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators).

Common Costs – Cost associated with services or products that are of joint benefit to both regulated and non-regulated business units.

Cost Driver – A measurable event or quantity which influences the level of costs incurred and which can be directly traced to an origin of the costs themselves.

Fully Allocated – Services or products bear the sum of the cost drivers plus an appropriate share of the indirect costs.

Incremental – Pricing services or products on a basis of only the incremental costs added by their operations while one or more pre-existing services, or products, support the fixed costs.

Non-regulated – Refers to services or products not subject to regulation by regulatory authorities.

Prevailing Market Rate – A generally accepted market value that can be substantiated by clearly comparable transactions, auction or appraisal.

Regulated – Refers to services or products subject to regulation by regulatory authorities.

Subsidization – The recovery of costs from one class of customers, business unit or entity, that are attributable to another.

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080677-EI & 090130-EI EXHIBIT 126

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS Kim Ousdahl (KO-10)

DATE 09/04/09

Guidelines for Cost Allocations and Affiliate Transactions:

The following Guidelines for Cost Allocations and Affiliate Transactions (Guidelines) are intended to provide guidance to jurisdictional regulatory authorities and regulated utilities and their affiliates in the development of procedures and recording of transactions for services and products between a regulated entity and affiliates. The prevailing premise of these Guidelines is that allocation methods should not result in subsidization of non-regulated services or products by regulated entities unless authorized by the jurisdictional regulatory authority. These Guidelines are not intended to be rules or regulations prescribing how cost allocations and affiliate transactions are to be handled. They are intended to provide a framework for regulated entities and regulatory authorities in the development of their own policies and procedures for cost allocations and affiliated transactions. Variation in regulatory environment may justify different cost allocation methods than those embodied in the Guidelines.

The Guidelines acknowledge and reference the use of several different practices and methods. It is intended that there be latitude in the application of these guidelines, subject to regulatory oversight. The implementation and compliance with these cost allocations and affiliate transaction guidelines, by regulated utilities under the authority of jurisdictional regulatory commissions, is subject to Federal and state law. Each state or Federal regulatory commission may have unique situations and circumstances that govern affiliate transactions, cost allocations, and/or service or product pricing standards. For example, The Public Utility Holding Company Act of 1935 requires registered holding company systems to price "at cost" the sale of goods and services and the undertaking of construction contracts between affiliate companies.

The Guidelines were developed by the NARUC Staff Subcommittee on Accounts in compliance with the Resolution passed on March 3, 1998 entitled "Resolution Regarding Cost Allocation for the Energy Industry" which directed the Staff Subcommittee on Accounts together with the Staff Subcommittees on Strategic Issues and Gas to prepare for NARUC's consideration, "Guidelines for Energy Cost Allocations." In addition, input was requested from other industry parties. Various levels of input were obtained in the development of the Guidelines from the Edison Electric Institute, American Gas Association, Securities and Exchange Commission, the Federal Energy Regulatory Commission, Rural Utilities Service and the National Rural Electric Cooperatives Association as well as staff of various state public utility commissions.

In some instances, non-structural safeguards as contained in these guidelines may not be sufficient to prevent market power problems in strategic markets such as the generation market. Problems arise when a firm has the ability to raise prices above market for a sustained period and/or impede output of a product or service. Such concerns have led some states to develop codes of conduct to govern relationships between the regulated utility and its non-regulated affiliates. Consideration should be given to any "unique" advantages an incumbent utility would have over competitors in an emerging market such as the retail energy market. A code of conduct should be used in conjunction with guidelines on cost allocations and affiliate transactions.

A. DEFINITIONS

1. Affiliates - companies that are related to each other due to common ownership or control.

2. Attestation Engagement - one in which a certified public accountant who is in the practice of public accounting is contracted to issue a written communication that expresses a conclusion about the reliability of a written assertion that is the responsibility of another party.

3. Cost Allocation Manual (CAM) - an indexed compilation and documentation of a company's cost allocation policies and related procedures.

4. Cost Allocations - the methods or ratios used to apportion costs. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators).

5. Common Costs - costs associated with services or products that are of joint benefit between regulated and non-regulated business units.

6. Cost Driver - a measurable event or quantity which influences the level of costs incurred and which can be directly traced to the origin of the costs themselves.

7. Direct Costs - costs which can be specifically identified with a particular service or product.

8. Fully Allocated costs - the sum of the direct costs plus an appropriate share of indirect costs.

9. Incremental pricing - pricing services or products on a basis of only the additional costs added by their operations while one or more pre-existing services or products support the fixed costs.

10. Indirect Costs - costs that cannot be identified with a particular service or product. This includes but not limited to overhead costs, administrative and general, and taxes.

11. Non-regulated - that which is not subject to regulation by regulatory authorities.

12. Prevailing Market Pricing - a generally accepted market value that can be substantiated by clearly comparable transactions, auction or appraisal.

13. Regulated - that which is subject to regulation by regulatory authorities.

14. Subsidization - the recovery of costs from one class of customers or business unit that are attributable to another.

B. COST ALLOCATION PRINCIPLES

The following allocation principles should be used whenever products or services are provided between a regulated utility and its non-regulated affiliate or division.

1. To the maximum extent practicable, in consideration of administrative costs, costs should be collected and classified on a direct basis for each asset, service or product provided.

2. The general method for charging indirect costs should be on a fully allocated cost basis. Under appropriate circumstances, regulatory authorities may consider incremental cost, prevailing market pricing or other methods for allocating costs and pricing transactions among affiliates.

3. To the extent possible, all direct and allocated costs between regulated and non-regulated services and products should be traceable on the books of the applicable regulated utility to the applicable Uniform System of Accounts. Documentation should be made available to the appropriate regulatory authority upon request regarding transactions between the regulated utility and its affiliates.

4. The allocation methods should apply to the regulated entity's affiliates in order to prevent

subsidization from, and ensure equitable cost sharing among the regulated entity and its affiliates, and vice versa.

5. All costs should be classified to services or products which, by their very nature, are either regulated, non-regulated, or common to both.

6. The primary cost driver of common costs, or a relevant proxy in the absence of a primary cost driver, should be identified and used to allocate the cost between regulated and non-regulated services or products.

7. The indirect costs of each business unit, including the allocated costs of shared services, should be spread to the services or products to which they relate using relevant cost allocators.

C. COST ALLOCATION MANUAL (NOT TARIFFED)

Each entity that provides both regulated and non-regulated services or products should maintain a cost allocation manual (CAM) or its equivalent and notify the jurisdictional regulatory authorities of the CAM's existence. The determination of what, if any, information should be held confidential should be based on the statutes and rules of the regulatory agency that requires the information. Any entity required to provide notification of a CAM(s) should make arrangements as necessary and appropriate to ensure competitively sensitive information derived therefrom be kept confidential by the regulator. At a minimum, the CAM should contain the following:

1. An organization chart of the holding company, depicting all affiliates, and regulated entities.

2. A description of all assets, services and products provided to and from the regulated entity and each of its affiliates.

3. A description of all assets, services and products provided by the regulated entity to non-affiliates.

4. A description of the cost allocators and methods used by the regulated entity and the cost allocators and methods used by its affiliates related to the regulated services and products provided to the regulated entity.

D. AFFILIATE TRANSACTIONS (NOT TARIFFED)

The affiliate transactions pricing guidelines are based on two assumptions. First, affiliate transactions raise the concern of self-dealing where market forces do not necessarily drive prices. Second, utilities have a natural business incentive to shift costs from non-regulated competitive operations to regulated monopoly operations since recovery is more certain with captive ratepayers. Too much flexibility will lead to subsidization. However, if the affiliate transaction pricing guidelines are too rigid, economic transactions may be discouraged.

The objective of the affiliate transactions' guidelines is to lessen the possibility of subsidization in order to protect monopoly ratepayers and to help establish and preserve competition in the electric generation and the electric and gas supply markets. It provides ample flexibility to accommodate exceptions where the outcome is in the best interest of the utility, its ratepayers and competition. As with any transactions, the burden of proof for any exception from the general rule rests with the proponent of the exception.

1. Generally, the price for services, products and the use of assets provided by a regulated entity to its non-regulated affiliates should be at the higher of fully allocated costs or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

2. Generally, the price for services, products and the use of assets provided by a non-regulated affiliate to a regulated affiliate should be at the lower of fully allocated cost or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

3. Generally, transfer of a capital asset from the utility to its non-regulated affiliate should be at the greater of prevailing market price or net book value, except as otherwise required by law or regulation. Generally, transfer of assets from an affiliate to the utility should be at the lower of prevailing market price or net book value, except as otherwise required by law or regulation. To determine prevailing market value, an appraisal should be required at certain value thresholds as determined by regulators.

4. Entities should maintain all information underlying affiliate transactions with the affiliated utility for a minimum of three years, or as required by law or regulation.

E. AUDIT REQUIREMENTS

1. An audit trail should exist with respect to all transactions between the regulated entity and its affiliates that relate to regulated services and products. The regulator should have complete access to all affiliate records necessary to ensure that cost allocations and affiliate transactions are conducted in accordance with the guidelines. Regulators should have complete access to affiliate records, consistent with state statutes, to ensure that the regulator has access to all relevant information necessary to evaluate whether subsidization exists. The auditors, not the audited utilities, should determine what information is relevant for a particular audit objective. Limitations on access would compromise the audit process and impair audit independence.

2. Each regulated entity's cost allocation documentation should be made available to the company's internal auditors for periodic review of the allocation policy and process and to any jurisdictional regulatory authority when appropriate and upon request.

3. Any jurisdictional regulatory authority may request an independent attestation engagement of the CAM. The cost of any independent attestation engagement associated with the CAM, should be shared between regulated and non-regulated operations consistent with the allocation of similar common costs.

4. Any audit of the CAM should not otherwise limit or restrict the authority of state regulatory authorities to have access to the books and records of and audit the operations of jurisdictional utilities.

5. Any entity required to provide access to its books and records should make arrangements as necessary and appropriate to ensure that competitively sensitive information derived therefrom be kept confidential by the regulator.

F. REPORTING REQUIREMENTS

1. The regulated entity should report annually the dollar amount of non-tariffed transactions

associated with the provision of each service or product and the use or sale of each asset for the following:

a. Those provided to each non-regulated affiliate.

b. Those received from each non-regulated affiliate.

c. Those provided to non-affiliated entities.

2. Any additional information needed to assure compliance with these Guidelines, such as cost of service data necessary to evaluate subsidization issues, should be provided.

ABS Consulting

Florida Power & Light

Storm Loss and Reserve Performance Analysis

February 2009

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 127
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Steven P. Harris (SPH-1)
DATE 09/03/09

FPL

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Risk Profile

The following is a summary description of storm risk profile performed for Florida Power & Light (FPL) by ABS Consulting. This document is based on FPL data and is intended to be used solely, by FPL, for estimation of potential future storm losses and probabilities.

INSURED	**Florida Power & Light**	
ASSETS	Transmission and Distribution (T&D) System consisting of: Transmission towers, and conductors; Distribution poles, transformers, conductors, lighting and other miscellaneous assets. General property and NEIL insured property.	
LOCATION	All T&D assets located within State of Florida	
ASSET VALUE	Normal T&D replacement value is estimated to be approximately $20.2 billion, of which approximately 18% is transmission and 82% is distribution.	
LOSS PERILS	Hurricanes, Category 1 to 5, and Tropical Storms losses to T&D. Deductible losses to insured general property and NEIL insured property from hurricanes.	
EXPECTED ANNUAL LOSS	$153.3 million	
5% AGGREGATE DAMAGE EXCEEDANCE VALUE	$683 million	
1% AGGREGATE DAMAGE EXCEEDANCE VALUE	$2,028 million	
	Reserve Performance	
Reserve Analysis Cases $215 m initial balance	**Expected balance at 5 years**	**Probability of negative balance within 5 years**
$100 million Annual Accrual	($117 million)	42%
$150 million Annual Accrual	$138 million	33%
$175 million Annual Accrual	$266 million	30%

1. Storm Loss Analysis

FPL's T&D systems and other property assets are exposed to and in the past have sustained damage from storms. The exposure of these assets to storm damage is described and potential losses are quantified in this report. Loss analyses were performed by ABS Consulting, using a computer model simulation program USWIND ™developed by EQECAT, an ABS Group Company. All results which are presented here have been calculated using USWIND, and the asset portfolio data provided by FPL.

The hurricane exposure is analyzed from probabilistic approach, which considers the full range of potential storm characteristics and corresponding losses. Probabilistic analyses identify the probability of damage exceeding a specific dollar amount. Damage to T&D assets is defined as the cost associated with repair and/or replacement of T&D assets necessary to promptly restore service in a post hurricane environment. This cost is typically larger than the costs associated with scheduled repair and replacement.

Probabilistic Annual Damage & Loss is computed using the results of over 100,000 random variable storms. Annual damage and loss estimates are developed for each individual site and aggregated to overall portfolio damage and loss amounts. Damage is defined as the cost associated with repair and/or replacement of T&D assets necessary to promptly restore service in a post-storm environment. This cost is typically larger than the costs associated with scheduled repair and replacement programs.

Factors considered in the analyses of the T&D assets include the location of FPL's overhead and underground T&D assets, the probability of storms of different intensities and/or landfall points impacting those assets, the vulnerability of those assets to storm damage, and the costs to repair assets and restore electrical service.

FPL's non-T&D assets consist of fossil and nuclear power plants, buildings, substations and other miscellaneous assets and are also exposed to storm perils. These assets are covered by insurance policies with deductible retentions. The deductible exposures for these portfolios of assets were modeled to determine their loss expectancies and impacts on the reserve. Other non-recovered cost from storm staging were also modeled.

Loss Estimation Methodology

The basic components of the hurricane risk analysis include:

- **Assets at risk:** define and locate
- **Storm hazard**: apply probabilistic storm model for the region
- **Asset vulnerabilities:** severity (wind speed) versus damage
- **Portfolio Analysis:** probabilistic analysis - damage/loss

These analysis components are summarized herein.

2. Assets at Risk

2.1 Transmission and Distribution Assets

FPL's T&D System assets consist of:

- Transmission towers, and conductors,
- Distribution poles, transformers,
- Conductors, lighting and
- Other miscellaneous assets.

The total normal replacement value of these assets is approximately $20.2 billion, 18% of which is transmission and 82% distribution. Normal replacement value is the cost of replacing the assets under normal non-catastrophe conditions.

FPL's T&D assets are distributed unevenly across their Florida service territory, encompassing a large portion of the State. These assets are geo-located located in the USWIND™ Storm model by latitude and longitude to capture the spatial distribution and concentration of these assets at risk.

Table 2-1 shows the distribution values within Florida for the counties that make up 92% of the total, indicating a concentration of values in the southern portion of the state. Figure 2-1 shows a map of FPL's transmission structures while Figure 2-2 shows a map of the distribution values indicating a similar concentration of values in south Florida Counties.

2.2 Non-Transmission and Distribution Assets

FPL's non-T&D assets consist of fossil and nuclear power plants, buildings, substations and other miscellaneous assets. The total replacement value of these assets is approximately $30 billion.

The FPL general and nuclear plant asset (non-T&D) portfolio is insured for storm losses under two insurance policies, with two per-occurrence deductibles. The deductible amounts represent self-insured retentions by FPL and are modeled as exposures to the reserve. Nuclear Electric Insurance Ltd. (NEIL) provides power plant property insurance for Turkey Point Units 1 through 4 and St. Lucie Units 1 and 2. The policy has a deductible of $10 million per occurrence/per site with coinsurance of 10% of the claim above that deductible. The balance of FPL's general plant assets, buildings, fossil power plants and substations are insured and have an aggregate per-occurrence deductible of $25 million.

Table 2-3 below, shows the replacement values and the distribution of values between transmission, distribution, general plant, and nuclear plant assets.

Table 2-1-
Distribution Replacement Values by County, Largest Counties

DISTRIBUTION COUNTY	2008 Asset Value
Dade	$4,304,369,834
Palm Beach	$3,061,099,330
Broward	$2,610,321,143
Brevard	$911,659,656
Lee	$721,100,921
Sarasota	$693,055,167
Volusia	$584,870,148
St Lucie	$518,890,514
Collier	$449,725,596
Manatee	$433,038,006
Martin	$364,605,705
Charlotte	$337,414,463
St Johns	$233,098,294
Other Counties	$1,270,606,032
TOTALS	**$16,493,854,808**

Table 2-2

Transmission Asset Replacement Value

TRANSMISSION	2008 Asset Value
TOTALS	$3,658,138,339

Table 2-3

FPL Asset Replacement Values

	$(Thousands)	%
Distribution	$ 16,493,854	33%
Transmission	$ 3,658,138	7%
General Plant	$20,138,897	40%
Nuclear Power Plants	$ 9,840,000	20%
TOTAL	$50,130,890	100%

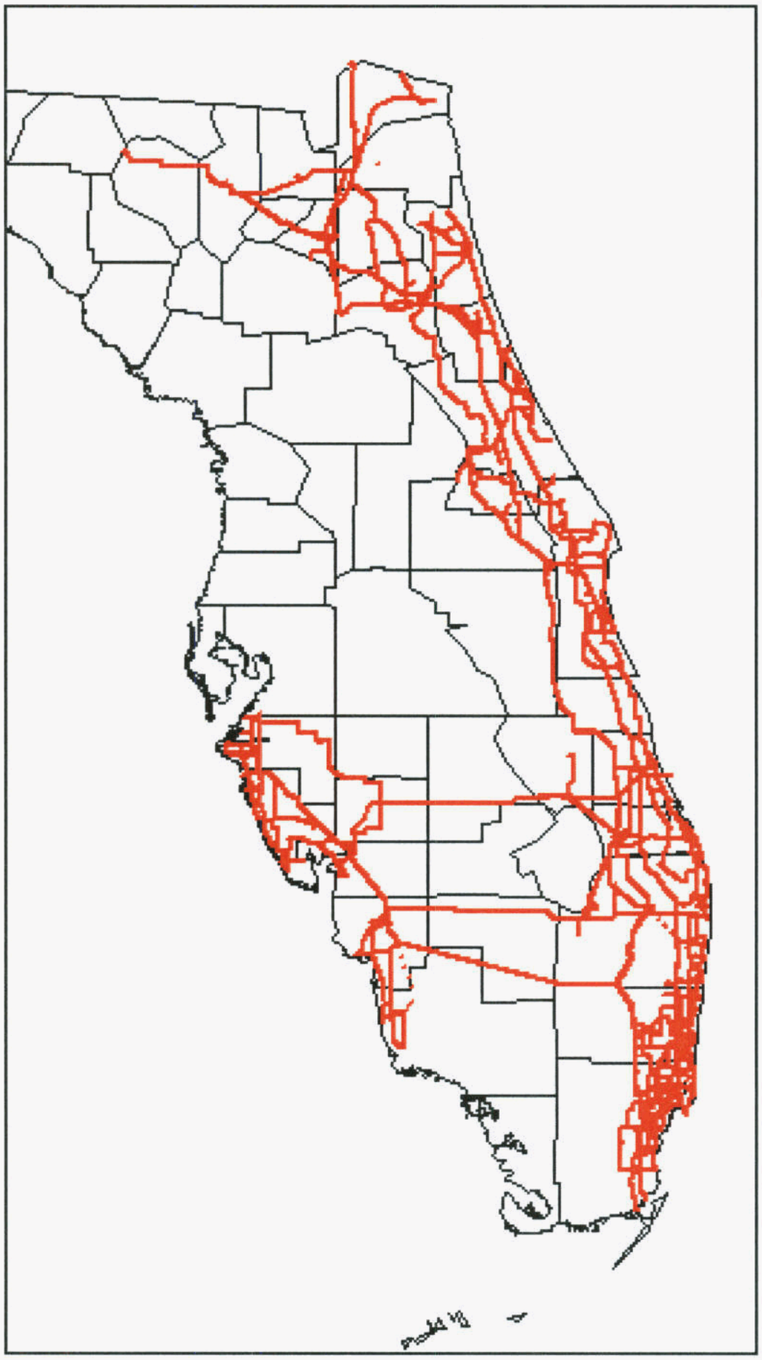

Figure 2-1: FPL Transmission Structures

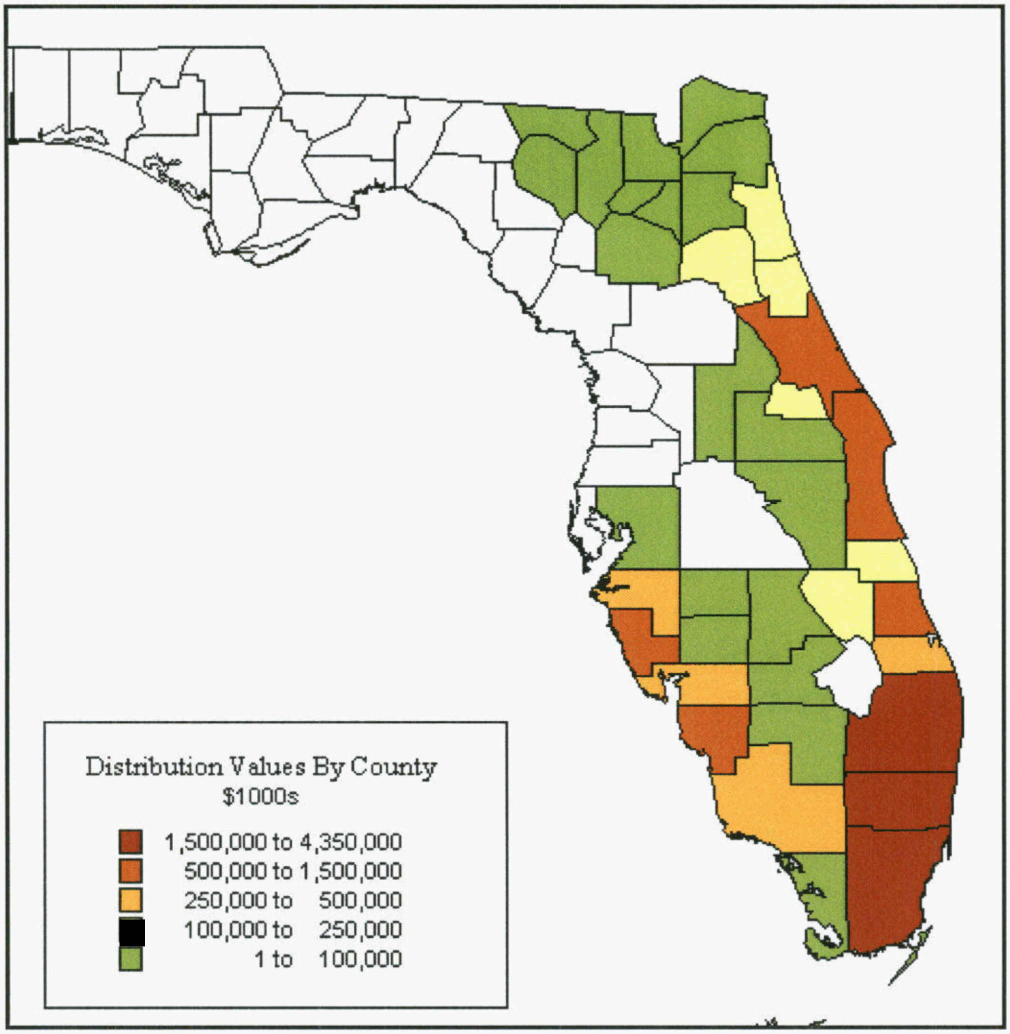

Figure 2-2: FPL Overhead Distribution Values

3. Windstorm Hazard in Florida

The historical record for hurricanes on the Gulf and Atlantic coasts of the United States consists of approximately 100 years for which reasonably accurate information is available. For example, since 1900, there have been over 60 hurricanes of Saffir-Simpson Intensity (SSI) 1 or greater (see Table 3-1 for description of the Saffir-Simpson Intensity scale) which have made landfall in the state of Florida. Going back further, written descriptions of storms are available, but it becomes increasingly difficult to estimate actual storm intensities and track locations in a reliable manner consistent with the later data. For this reason all hypothetical storms used in this analysis, as well as their corresponding frequencies, have been based only on hurricanes that have occurred since 1900.

Since the historical record is too sparse to simply extrapolate future hurricane landfall probabilities, a series of hypothetical storms was generated in the USWIND™ probabilistic storm data base, essentially "filling in" the gaps in the historical data. This provides an estimate of future potential storm locations (landfall), track, severity and frequency consistent with the observed historical data.

EQECAT developed its hurricane model (Reference 1), using the National Oceanic and Atmospheric Administration (NOAA) model as the base, to determine individual risk wind speeds. The NOAA model was designed to model only a few specific types of storms. While the eye of the hurricane follows the selected track, the EQECAT model uses up to a dozen different storm parameters to estimate wind speeds at all distances away from the eye. The version of USWIND currently certified by the Florida Commission on Hurricane Loss Projection Methodology (FCHLPM) is based in part on the FCHLPM's Official Storm Set, which includes hurricanes affecting Florida during the period 1900 through 2007.

The hurricane intensities used for the analyses conform to basic NOAA information regarding hurricane intensity recurrence relationships corresponding to locations along the coast. Much of FPL's service territory includes the coastal area where many of these hurricanes have made landfall.

Table 3-1

THE SAFFIR-SIMPSON INTENSITY SCALE
(NOTE THAT WINDSPEEDS GIVEN ARE 1-MINUTE SUSTAINED)

SSI	Central Pressure (mb)	Maximum Sustained Winds (mph)	Storm-Surge Height (ft)	Damage
1	≥ 980	74-95	4-5	Damage mainly to trees, shrubbery, and unanchored mobile homes
2	965-979	96-110	6-8	Some trees blown down; major damage to exposed mobile homes; some damage to roofs of buildings
3	945-964	111-130	9-12	Foliage removed from trees; large trees blown down; mobile homes destroyed; some structural damage to small buildings
4	920-944	131-155	13-18	All signs blown down; extensive damage to roofs, windows, and doors; complete destruction of mobile homes; flooding inland as far as 6 mi.; major damage to lower floors of structures near shore
5	< 920	> 155	> 18	Severe damage to windows and doors; extensive damage to roofs of homes and industrial buildings; small buildings overturned and blown away; major damage to lower floors of all structures less than 15 ft. above sea level within 500m of shore

3.2 Tropical Storm Hazard

In addition to storms strong enough to be classified as hurricanes, Florida is exposed to the threat of tropical storms (one-minute sustained wind speeds between 39 and 74 mph). The frequency of tropical storms in Florida is approximately equal to that of hurricanes (note that the wind speed range associated with hurricanes is much wider, i.e. 74 mph to well over 155 mph).

EQECAT's tropical storm model was developed using methods very similar to those used to develop the hurricane model, generating a series of hypothetical storms representing the full range of tropical storms in terms of landfall location and track, severity, and frequency consistent with the observed historical data.

3.3 Winter Storm Hazard

On average, about 15 mid-latitude storms a year bring high winds to Florida, mainly during the winter. Most of these storms have winds only in the 40 to 50 mph gust range and thus have little effect. The more severe events, however, can cause losses on the same scale as a tropical storm or weak hurricane.

In assessing this hazard, historical windstorm data for the past 45 years was obtained from the National Climatic Data Center. This data included gust wind speed observations for over 600 storms, at a network of over 300 stations.

4. Asset Vulnerabilities

Aerial T&D lines and structures have suffered damage in past hurricanes, tropical storms and winter storms. Damage patterns tend to be most severe in coastal areas. Damage to inland aerial lifelines tends to be less severe with greater contributions to damage from wind-borne debris. The types of wind-borne debris can include tree and tree limbs, and roofing materials as well as structure debris at higher wind speeds.

FPL aerial T&D structures are designed to sustain design-level hurricane winds. These design criteria specify design wind speeds for both T&D structures. Design criteria for transmission structures are microzoned, or segmented, into geographic areas that correspond to the expected wind hazard for the area. Distribution poles, on the other hand, are assumed to have one design standard for the entire service territory.

Vulnerability of T&D assets are based upon wind speeds and FPL provided storm cost data from hurricanes since 1992. Storm cost data has included consideration for Florida Public Service Commission Rule 25-6.0143 – Use of Accumulated Provision Accounts 228.1, 228.2 and 228.4 for historical storms from the 2004 through 2008 hurricane seasons. Other vulnerabilities were developed using FPL-provided data on hurricane, tropical storm, and winter storm damage data, FPL design standards, and engineering judgments of the relative performance of the structures and material types.

Vulnerabilities of non-T&D assets are modeled using standard classes of commercial buildings and specialized utility infrastructure vulnerabilities in USWIND.

5. Summary of Portfolio Analysis

ABS analyzed the FPL portfolio of T&D assets and other non-T&D assets subject to a suite of probabilistic storms using the proprietary computer program, USWIND. The probabilistic storm analyses provide non-exceedance probabilities over a range of loss levels while the scenario landfall storm series provides a damage distribution for selected storms at landfalls within the areas of FPL's highest asset concentrations.

5.1 Storm Probabilistic Analysis

The probabilistic loss analysis is performed using USWIND. The hurricane hazard uses the USWIND probabilistic database which models the coastline in 10 mile segments and models more than 1,500 hypothetical storms for each segment. The net result is a stochastic storm database of more than 500,000 events that represents possible hurricanes affecting the eastern United States, along both the Gulf and the Atlantic coasts. Each hurricane in the database has been defined by associating a central pressure with a unique storm track. In addition, each hurricane is assigned an annual frequency of occurrence, which depends on the storm track location and the storm intensity as measured by central pressure.

Tropical storms are modeled using a set of approximately 250,000 and additional events, representing the full range of potential storms affecting the Gulf and Atlantic coasts of the United States. As in the stochastic hurricane database, each tropical storm in the database has been defined by associating a central pressure with a unique storm track. In addition, each tropical storm is assigned an annual frequency of occurrence, which depends on the storm track location and the storm intensity as measured by central pressure. Loss expectancies from winter storms are based on the results from prior analyses adjusted for current asset valuation of distribution assets at risk. This exposure is included in estimates of the Expected Annual Losses below, but have not been included in the reserve performance analysis due to the small value.

For each location in the portfolio, the wind speed is calculated, and based on the type of asset, the degree of damage is estimated. The result for each asset location is an estimate of the mean damage.

5.2 Other Reserve Exposures

In addition to T&D storm losses and non-T&D deductible exposures discussed above, FPL's reserve may be called upon for payment of uninsured losses resulting from other causes. These include

- Storm staging costs
- Retrospective insurance assessment from industry nuclear accidents and
- Losses in excess of insurance coverage from nuclear accidents at FPL plants.

Staging Costs for Non-Landfalling Storms

FPL monitors hurricane forecasts and arranges for the pre-positioning of personnel and equipment, "staging", in anticipation of post hurricane storm restoration activities. These decisions are made in advance of hurricane landfall. On occasion, these staging decisions are taken and actual hurricane landfall occurs outside FPL's service territory. The central issue with staging costs is the probability that hurricane forecasts (where and at what intensity) may differ from actual hurricane landfalls.

A model for staging costs was developed using staging cost and decision information provided by FPL. The input parameters to the model are: forecasted landfall location (milepost), forecasted intensity (wind speed), actual landfall location (milepost), and actual intensity (wind speed). Staging costs are only calculated for situations in which the forecasted landfall is within FPL's service territory, and the actual landfall is not within FPL's service territory. For these situations, the staging costs are determined on the basis of the forecasted landfall location and intensity, based on staging cost information provided by FPL. For all other situations, the staging cost is assumed to be zero. The expected annual loss from staging is estimated to be $3.5 million per year.

Nuclear Exposures

FPL reserve exposures due to property damage and third party liabilities could arise from two sources:

- Nuclear accidents at FPL's four nuclear units located at Turkey Point and at St. Lucie and
- Nuclear accidents at plants in nuclear mutual insurance pools

Reserve obligations could result from these exposures as a result of mutual insurance obligation retrospective assessments ("Retros") or as a result of low probability events and losses in excess of insurance coverage. Potential financial exposures to the reserve were developed using nuclear industry studies that provide the frequency and severity of nuclear accidents. Estimates of the frequency and the expected annual losses from these events are very low in comparison with storm related exposures. These exposures are included in estimates of the Expected Annual Losses below, but have not been included in the performance analysis of reserve due to their small amounts.

Given the annual frequency and the portfolio loss for each asset class and peril, a probabilistic database of losses is developed. Using this database, various loss non-exceedance distributions are generated. The expected annual loss to FPL's reserve from these sources are shown below:

Table 5-1

Expected Annual Losses to Reserve

Expected Annual Losses	$ (Millions)	Comments
T&D Assets - Hurricane Peril and Tropical Storms	134.7	SSI 1 through 5 Sustained wind speeds of 39-74 Mph
Non T&D General Property Deductibles-Hurricane	9.8	Losses arising from payment of deductibles on insurance policies
NEIL Plant Deductibles - Hurricane	3.9	Losses arising from payment of deductibles on insurance policies
Storm Staging Costs	4.9	FPL Pre-storm mobilization
Distribution Assets - Winter Storms[1]	2	Gust wind speeds of 40-50 Mph
Retrospective Assessments from industry nuclear accidents [1]	1	Property and third-party liability assessments from mutual insurers
Losses in excess of insurance from FPL nuclear accidents [1]	1	Property losses to FPL nuclear plants in excess of insurance
Totals	$157.3	

Note 1: These losses are not included in the reserve performance analysis.

Aggregate Storm Damage Exceedance

Aggregate storm damage exceedance calculations are developed by keeping a running total of damage from ***all possible events*** in a given time period. At the end of each time period, the aggregate damage for all events is then determined by probabilistically summing the damage distribution from each event, taking into account the event frequency. The process considers the probability of having zero events, one event, two events, etc. during the time period.

A series of probabilistic analyses were performed, using the vulnerability curves derived for FPL assets and the computer program USWIND. A summary of the analysis is presented in Table 5-2, which shows the aggregate damage (i.e. deductible is “0”) exceedance probability layers between zero and over $2,000 million.

For each damage layer shown, the probability of damage exceeding a specified value is shown. For example, the probability of damage exceeding $1,000 million in one year is 3.0%. The analysis calculates the probability of direct T&D damage, deductible losses and storm staging costs from all storms and aggregates the total, resulting in increasing exceedance probabilities.

Table 5-2

FPL
AGGREGATE DAMAGE EXCEEDANCE PROBABILITIES

Damage Layer ($x1,000)	1 Year Exceedance Probability
> 500	78.2%
100,000	30.5%
200,000	18.0%
300,000	11.8%
400,000	8.59%
500,000	6.90%
600,000	5.60%
700,000	4.67%
800,000	4.04%
900,000	3.44%
1,000,000	3.00%
1,100,000	2.74%
1,200,000	2.44%
1,300,000	2.10%
1,400,000	1.88%
1,500,000	1.69%
1,600,000	1.53%
1,700,000	1.39%
1,800,000	1.28%
1,900,000	1.19%
2,000,000	1.03%

6. Hurricane Landfall Analyses for SSI Ranges

In order to provide further insight into FPL's risk profile, the full set of stochastic hurricane events were analyzed by landfall for five storm intensities, SSI 1 through 5. The storm series landfall locations begin in the areas of highest asset concentration, storm frequency and severity in south Florida. The landfall locations are at mile posts 1430 through 1770. Figure 6-1 illustrates the landfall locations. These mile posts extend north from Dade County at approximately 10 mile intervals.

The full set of stochastic storms within each SSI category was analyzed on FPL's T&D portfolio. For each milepost and SSI category, the frequency-weighted average damage was computed from all stochastic storms making landfall within 10 nautical miles of a given milepost and within that SSI category. Figures 6-2 through 6-6 provide these results graphically.

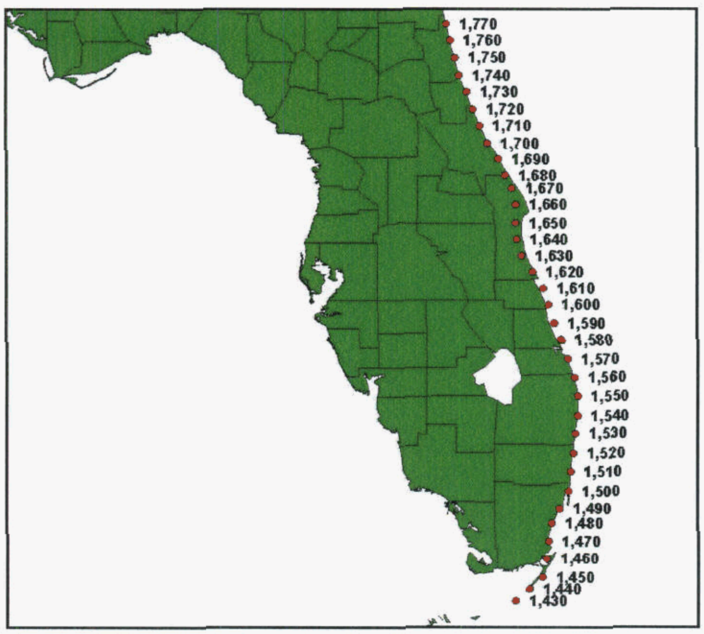

Figure 6-1: Storm Landfall Mile Posts

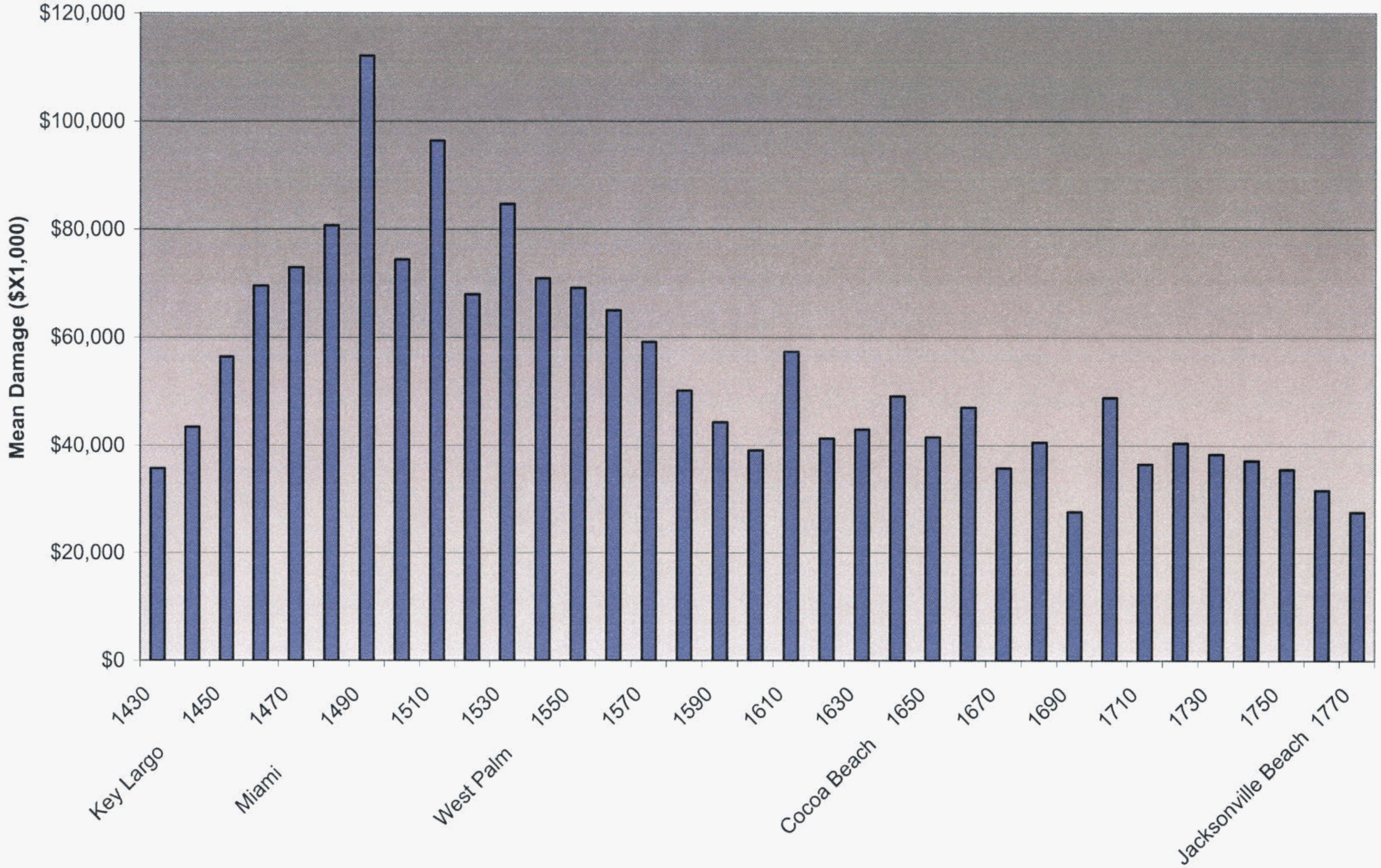

Figure 6-2: Frequency Weighted Average T&D Damage from SSI 1 Landfalls

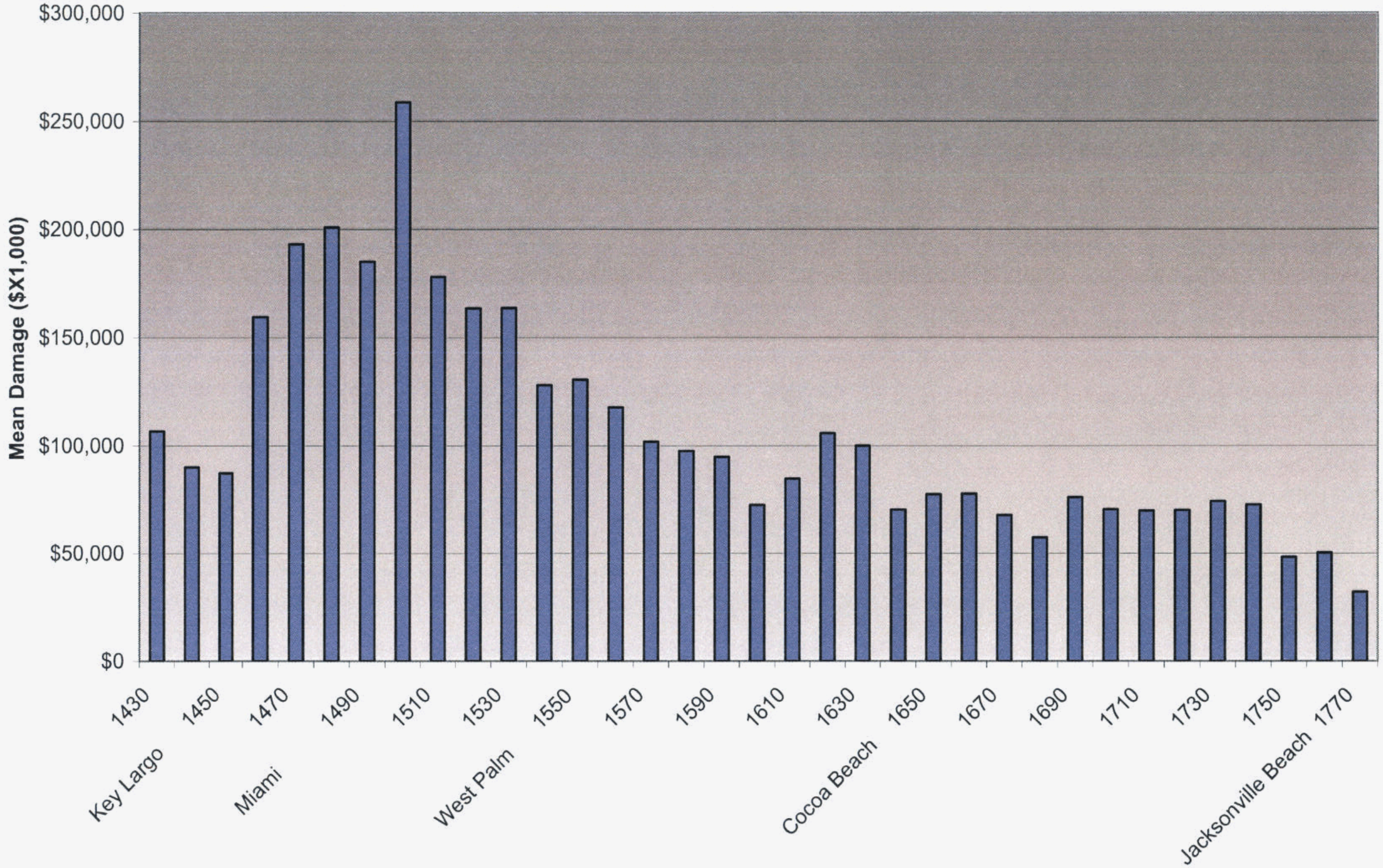

Figure 6-3: Frequency Weighted Average T&D Damage from SSI 2 Landfalls

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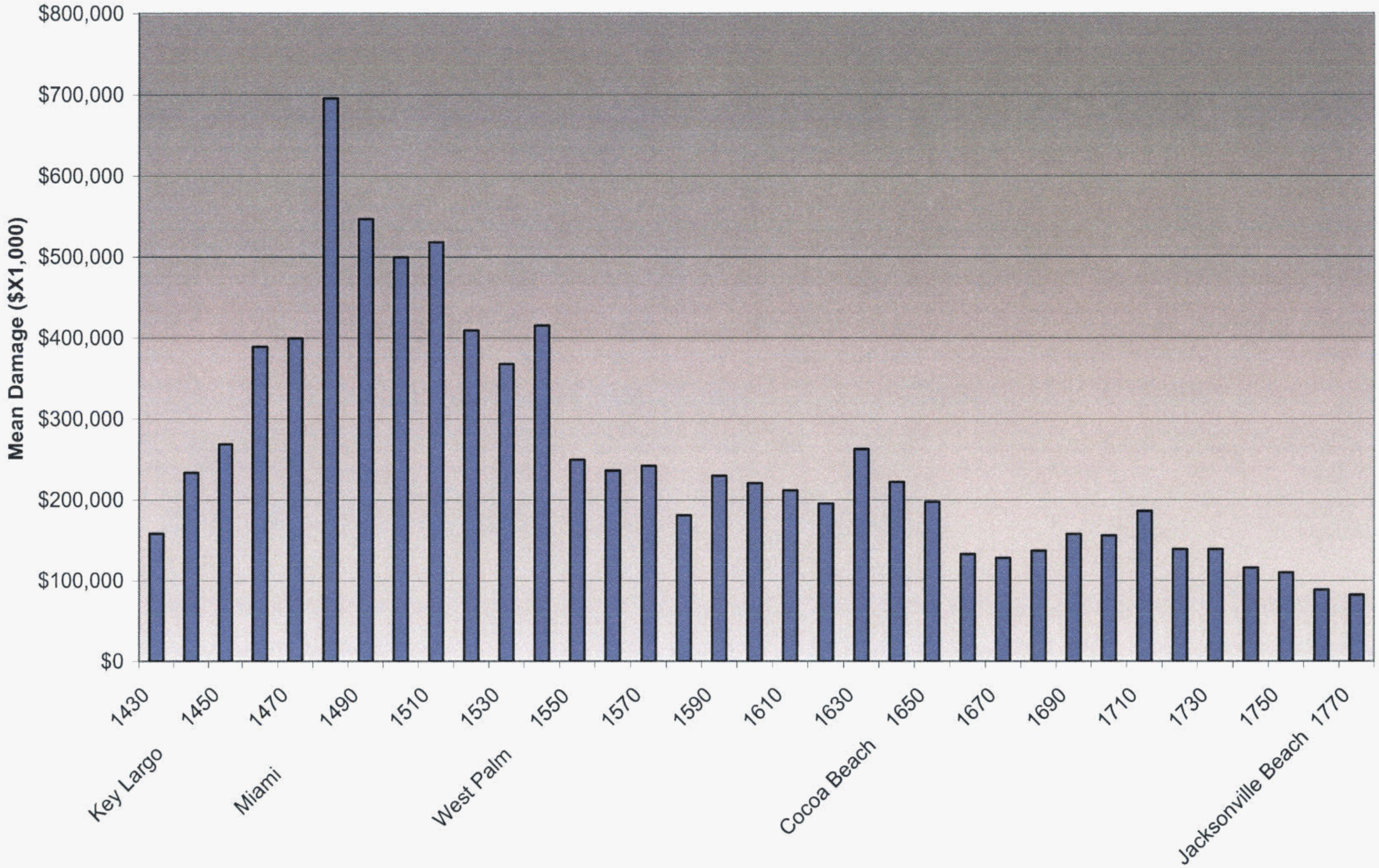

Figure 6-4: Frequency Weighted Average T&D Damage from SSI 3 Landfalls

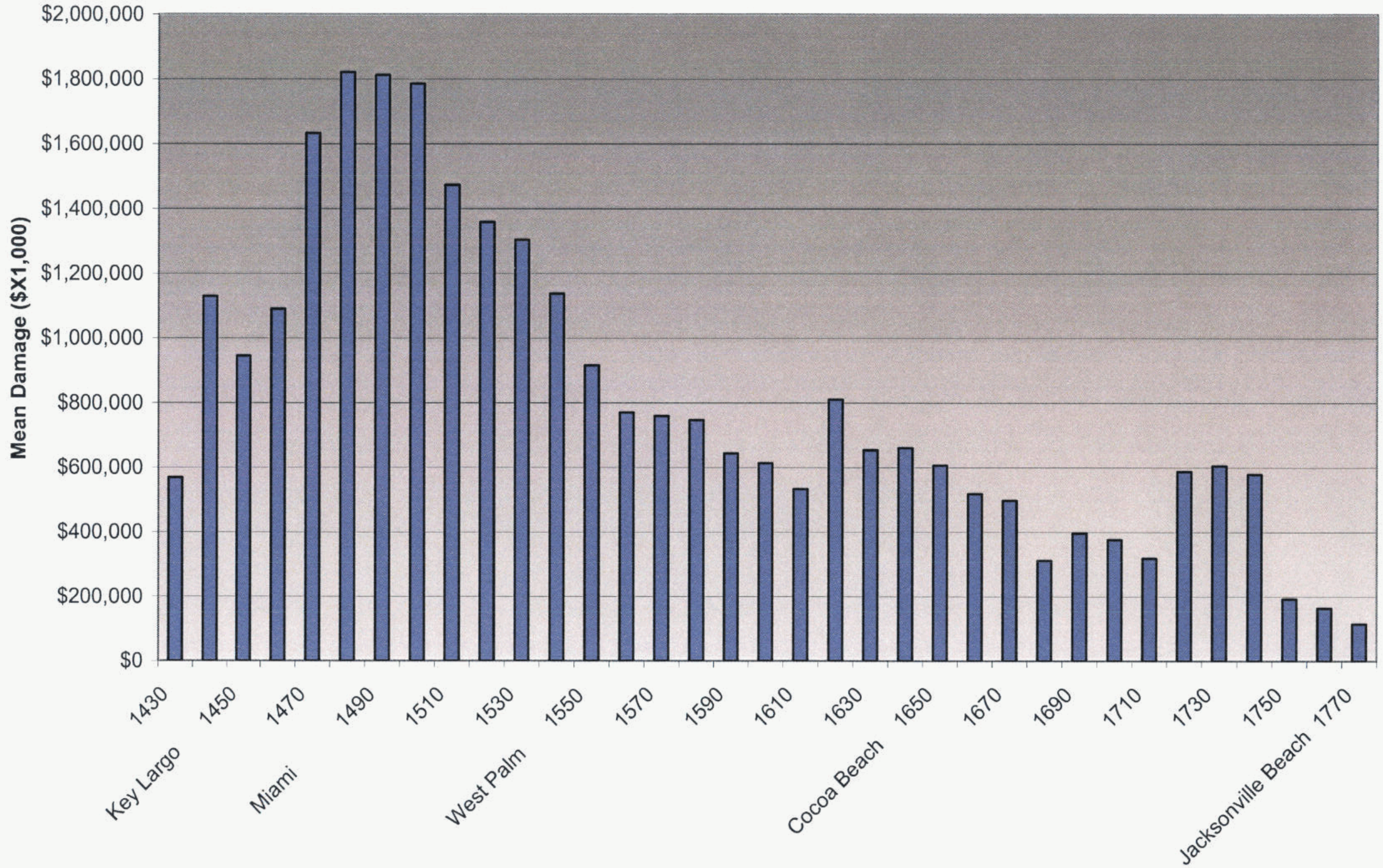

Figure 6-5: Frequency Weighted Average T&D Damage from SSI 4 Landfalls

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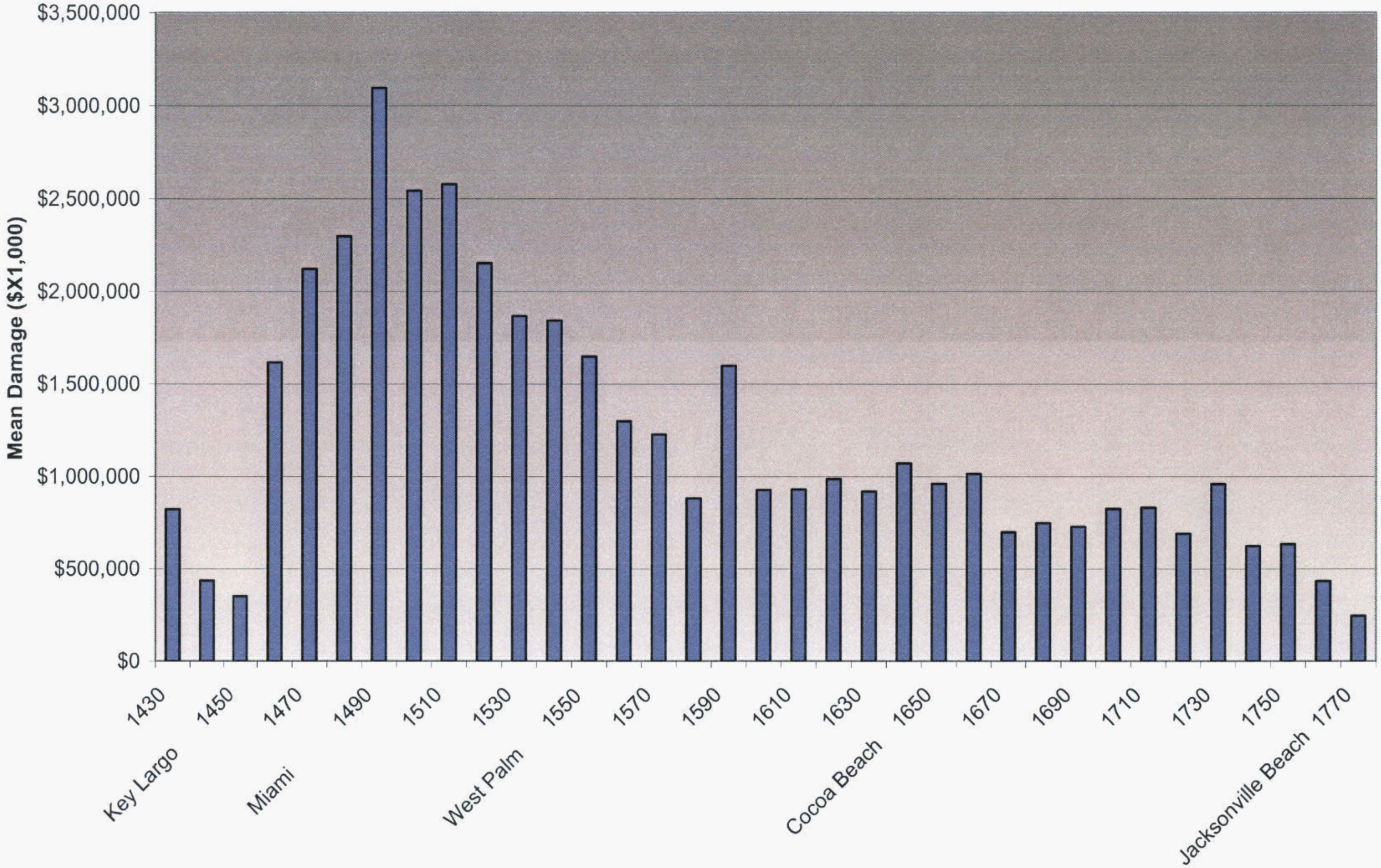

Figure 6-6: Frequency Weighted Average T&D Damage from SSI 5 Landfalls

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7. Reserve Performance Analysis

A probabilistic analysis of losses from storms was performed to determine their potential impact on FPL's reserve. The analysis included T&D losses, and insurance deductibles paid on non-T&D assets and storm staging costs. The expected annual loss analyzed in the reserve performance is $153.3 million, as described in the Loss Analysis Section.

The expected annual loss estimate represents the average annual cost associated with repair of hurricane damage and service restoration over a long period of time.

Analysis

The reserve performance analysis consisted of performing 10,000 iterations of hurricane loss simulations within the FPL service territory, each covering a 5-year period, to determine the effect of the charges for losses on the FPL reserve. Monte Carlo simulations were used to generate loss samples for the analysis. The analysis provides an estimate of the reserve assets in each year of the simulation, accounting for the annual accrual, investment income, expenses, and losses using a financial model.

Assumptions

The analysis performed included the following assumptions

- All computations were performed on an after tax basis.
- All results are shown in constant 2008 dollars.
- Asset values and storm losses were assumed to increase by 5% per year.

- Investment earnings were assumed to grow at an after tax rate of 3.45%.
- Negative reserve balances are assumed to be financed with an unlimited line of credit costing 4% after tax.

Analysis Results

The annual accrual cases of $100 million, $150 million, $175 million were analyzed with two assumptions for years in a simulation where the reserve balances becomes negative due to storm losses. The first assumes that the negative balances are recovered through a normal rate process, but are not recovered by the reserve. The second assumes that the negative balances are returned to the reserve through special assessments over a two year period. The two cases analyzed are:

1. No reserve fund recovery of negative balances occurs, and
2. Recovery of negative reserve fund balances occurs over two years.

In years when storm losses exceed the reserve fund balance, the fund has a negative balance. In cases where no recovery of these negative balances was assumed, the deficit was covered by borrowing funds (at a rate of 4.5%) and the annual year accruals are the only sources to pay down this debt and restore the fund to positive balances. The second cases analyzed assumes that in any year that the reserve became negative, the deficit is recovered by the reserve with special assessments over the following five-year period.

The analysis results for each of the accrual trials analyzed are shown in Figures 7-1 through 7-6 below. These results show the mean (expected) reserve fund balance as well as the 5th and 95th percentiles. All 10,000 Monte Carlo simulations assume an initial reserve balance of $215 million.

The mean values of these simulation results are shown in Table 7-1. The 95th percentile upper and 5th percentile lower bounds of the cases are shown and noted with their probability of hurricane losses exceeding this fund value. For the case with a $100 million annual accrual and no recoveries of negative balances, the mean reserve balance is negative ($117 million) and has about a 42% probability of losses less than zero in the five year time interval. The reserve has a 7% probability of having a balance greater than $650 million at the end of the five year simulation.

Similarly, for the case $175 million accrual case, the mean reserve balance is $266 million and has about a 30% probability of losses less than zero in the five year time interval. The reserve has a 55% probability of having a balance greater than $650 million at the end of the five year simulation.

Similar results are presented for cases with recoveries of negative balances over a two year period.

Table 8-1
FPL
RESERVE PERFORMANCE ANALYSIS RESULTS

Annual Accrual ($m)	Recovery of Deficits	Mean Reserve Balance ($m)	5th%ile Reserve Balance ($m)	95th%ile Reserve Balance ($m)	Probability Balance<$0	Probability Balance>$650m
$100	No Recovery	($117)	($2,220)	$673	42%	7%
$150	No Recovery	$138	($1,938)	$931	33%	41%
$175	No Recovery	$266	($1,812)	$1,065	30%	55%
$100	2 Year Recovery	$135	($828)	$666	42%	6%
$150	2 Year Recovery	$382	($602)	$930	33%	42%
$175	2 Year Recovery	$475	($602)	$1,063	30%	56%

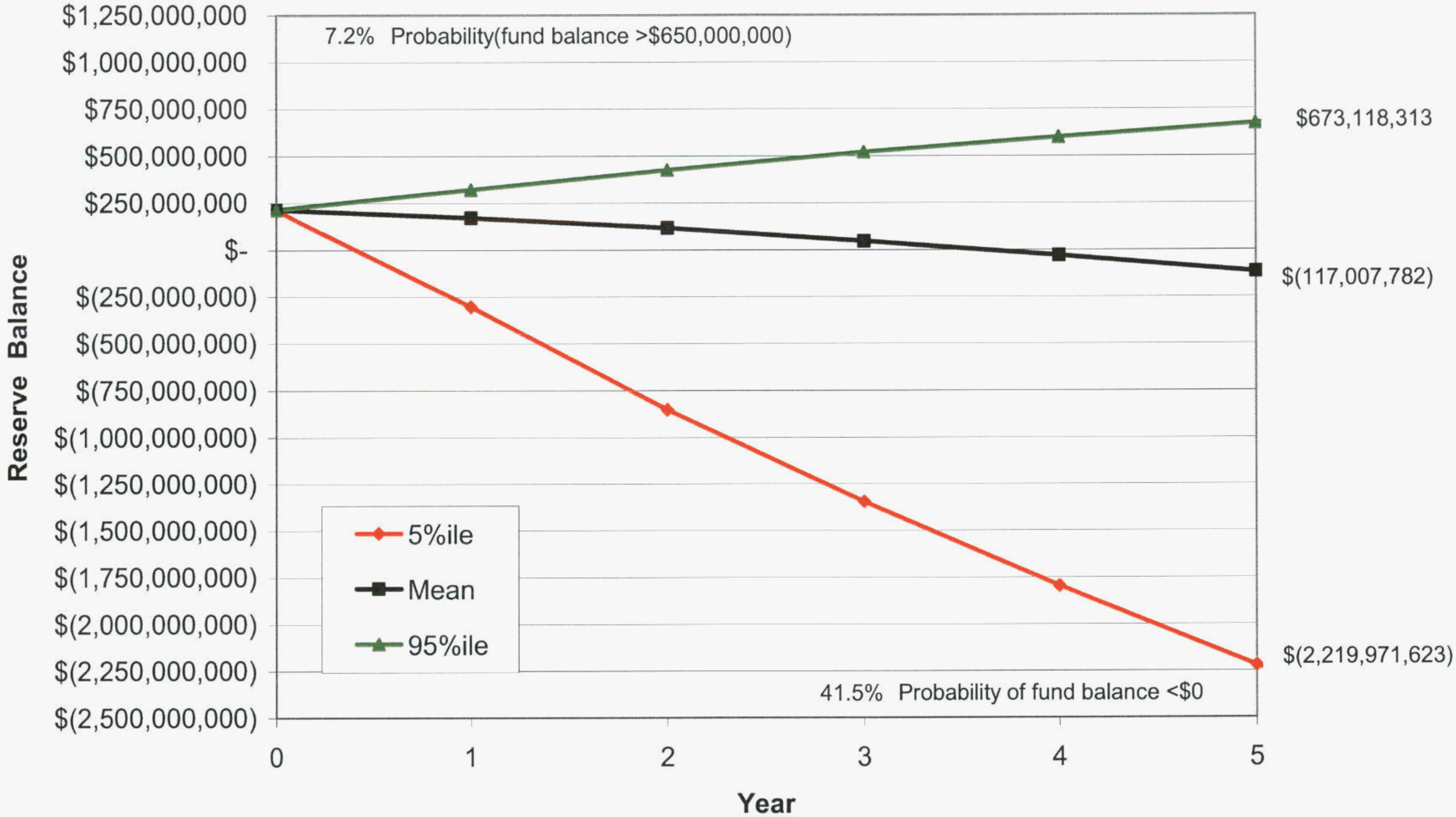

Figure 7-1: Reserve Performance Analyses: $100 million accrual

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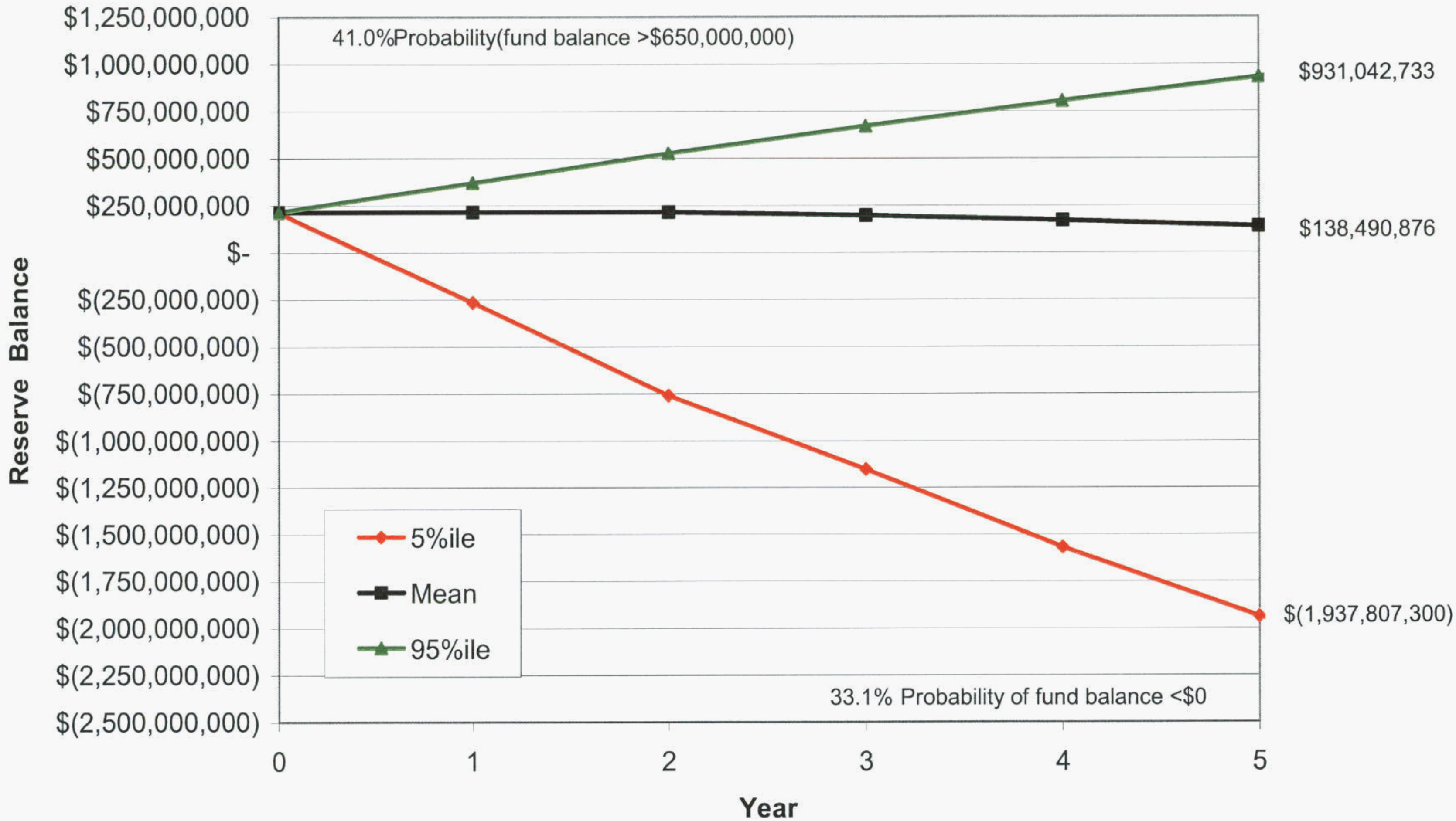

Figure 7-2: Reserve Performance Analyses: $150 million accrual

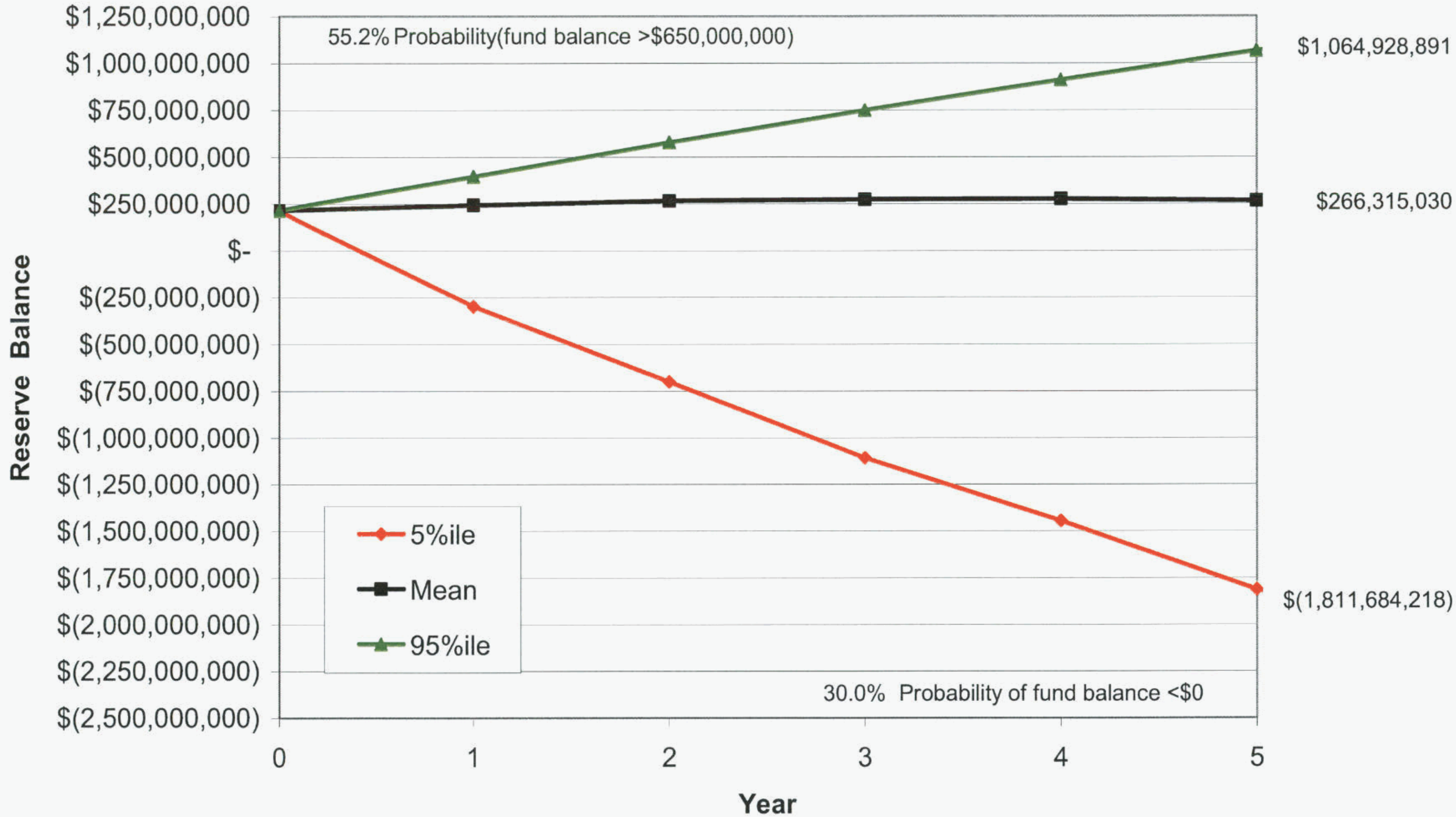

Figure 7-3: Reserve Performance Analyses: $175 million accrual

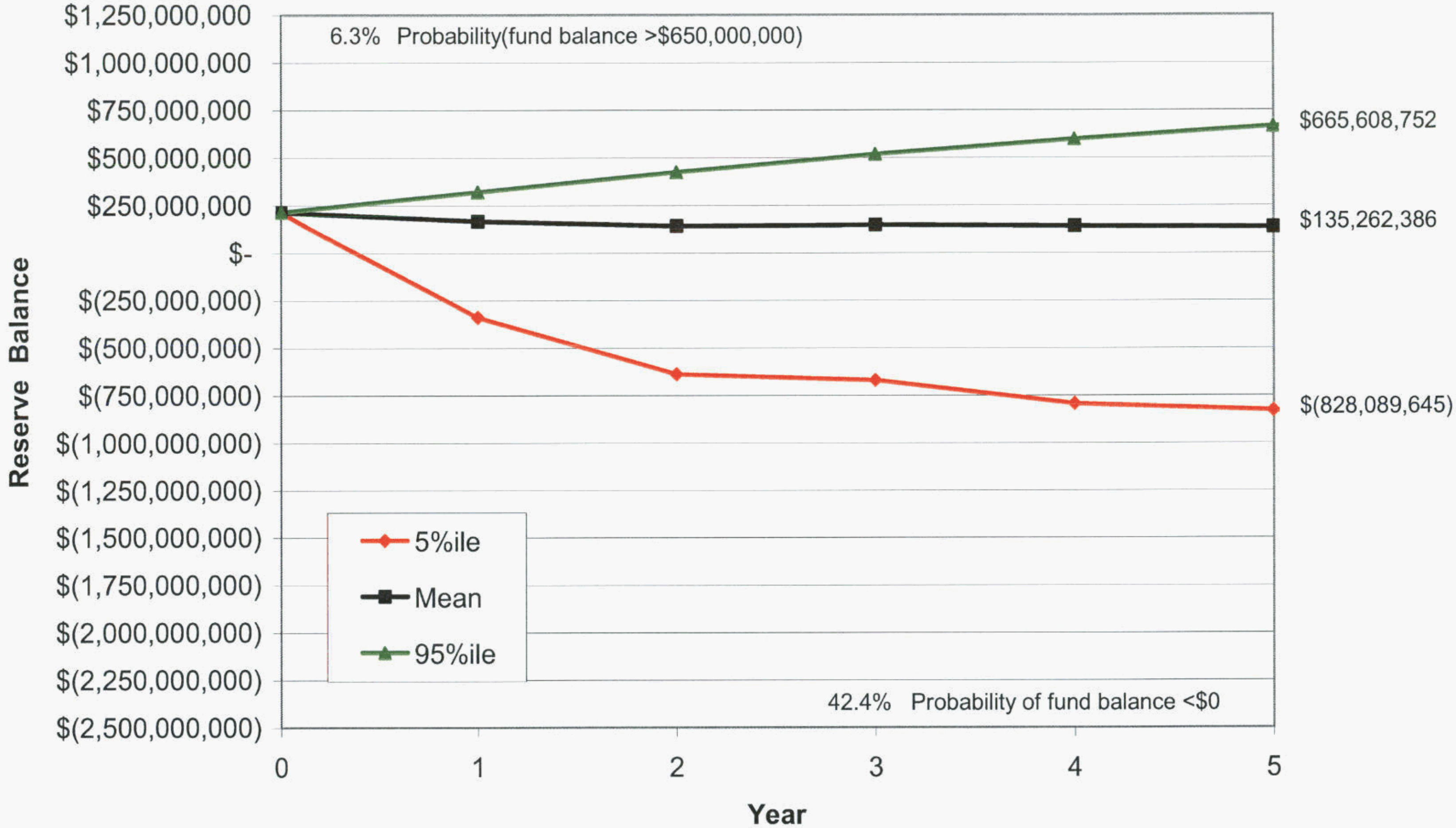

Figure 7-4: Reserve Performance Analyses: $100 million accrual, with 2 year Recovery

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Performance Analysis
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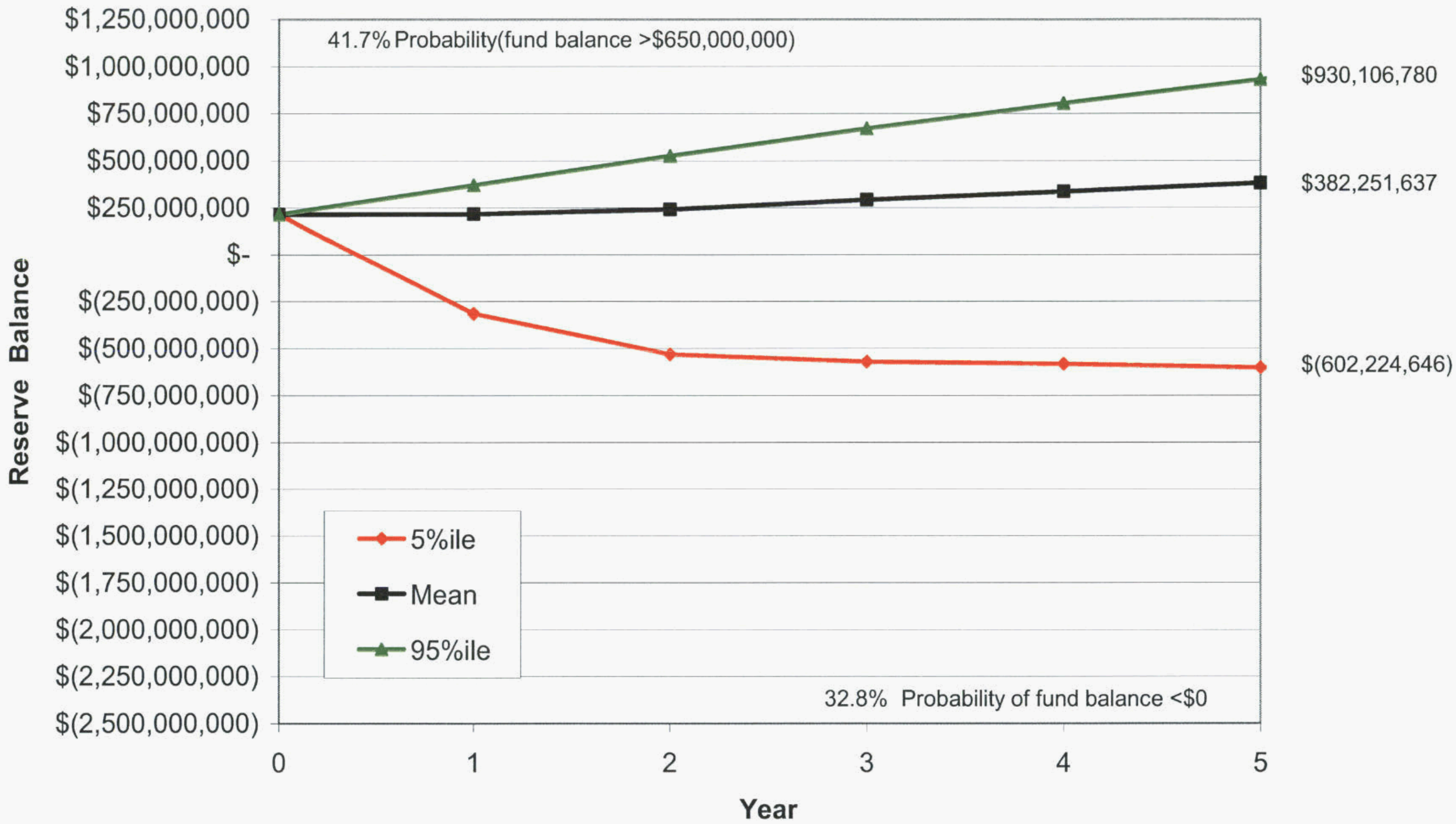

Figure 7-5: Reserve Performance Analyses: $150 million accrual, with 2 year Recovery

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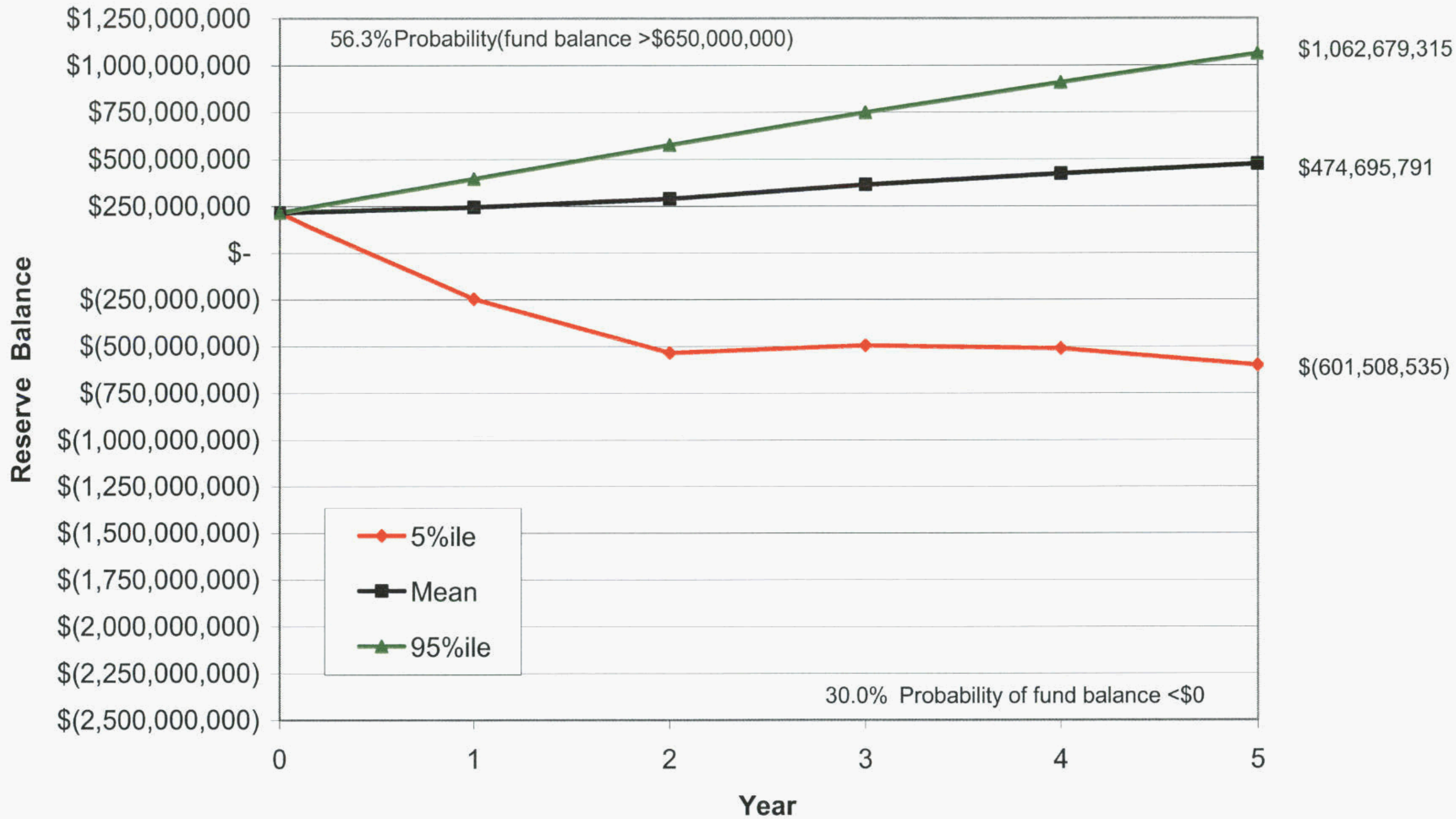


Figure 7-6: Reserve Performance Analyses: $175 million accrual, with 2 year Recovery

8. References

1. ""Florida Commission on Hurricane Loss Projection Methodology", EQECAT, an ABS Group Company, February 2008.

FLORIDA PUBLIC SERVICE COMMISSION

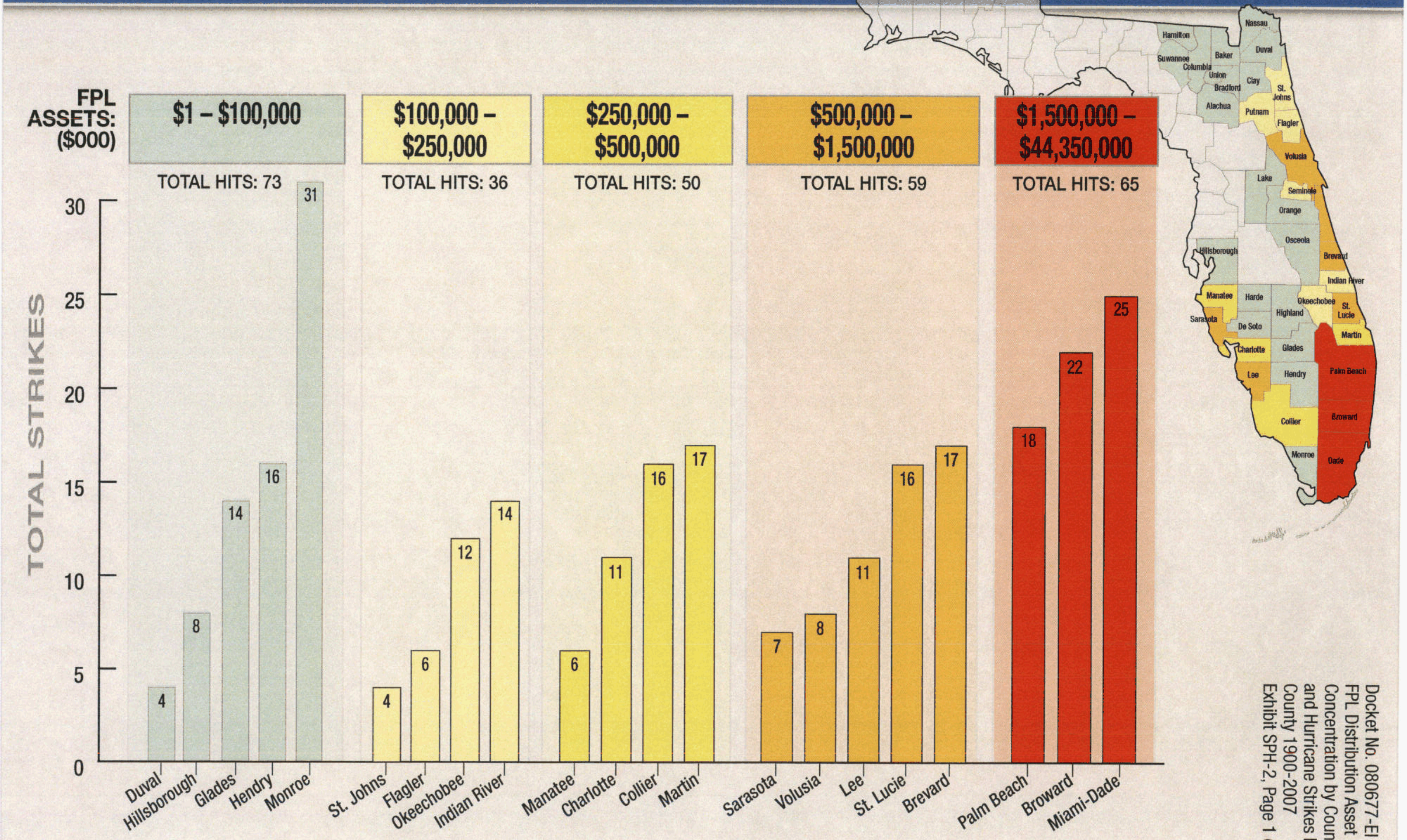
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 128

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS Steven P. Harris (SPH-2)

DATE 09/03/09

FPL Distribution Asset Concentration by County and Hurricane Strikes by County 1900-2007



Source: NWS NHS 46

Docket No. 080677-EI
FPL Distribution Asset
Concentration by County
and Hurricane Strikes by
County 1900-2007
Exhibit SPH-2, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

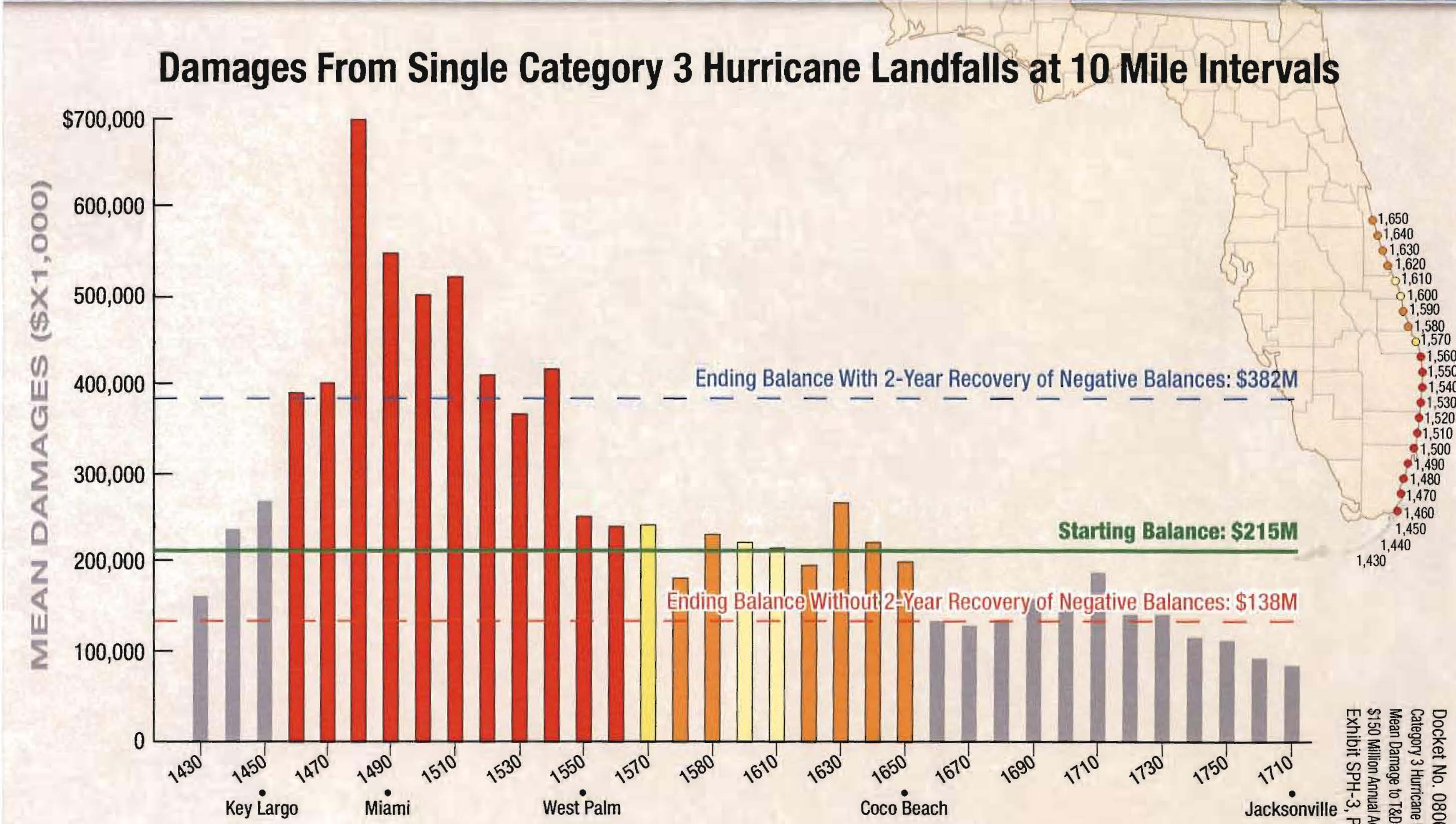
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 129

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS Steven P. Harris (SPH-3)

DATE 09/03/09

Category 3 Hurricane Landfalls and Mean Damage to T&D Compared to $150 Million Annual Accrual Case



Single Category 3 Hurricane Landfalls at 10 Mile Interval Mileposts and Mean Damage to T&D*
Compared against Starting and Ending Reserve Balances for $150 million Accrual Cases, with and without Recovery of Negative Balances
**Note: Frequency Weighted Average Damage*

Docket No. 080677-EI
Category 3 Hurricane Landfalls and Mean Damage to T&D Compared to $150 Million Annual Accrual Case
Exhibit SPH-3, Page 1 of 1

EXHIBIT WEA-1

QUALIFICATIONS OF WILLIAM E. AVERA

Q. What is the purpose of this exhibit?

A. This exhibit describes my background and experience and contains the details of my qualifications.

Q. What are your qualifications?

A. I received a B.A. degree with a major in economics from Emory University. After serving in the U.S. Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas (PUCT) as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission ("FERC"), as well as the Federal Communications Commission ("FCC"), the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in 39 states.

In 1995, I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern

University. I hold the Chartered Financial Analyst (CFA®) designation and have served as Vice President for Membership of the Financial Management Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners ("NARUC") Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached.

WILLIAM E. AVERA

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

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Austin, Texas 78751
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fincap@texas.net

Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal,
FINCAP, Inc.
(Sep. 1979 to present)

Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (over 150 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.

Director, Economic Research Division,
Public Utility Commission of Texas
(Dec. 1977 to Aug. 1979)

Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.

Manager, Financial Education,
International Paper Company
New York City
(Feb. 1977 to Nov. 1977)

Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance,
The University of Texas at Austin
(Sep. 1979 to May 1981)
Assistant Professor of Finance,
(Sep. 1975 to May 1977)

Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.

Assistant Professor of Business,
University of North Carolina at Chapel Hill
(Sep. 1972 to Jul. 1975)

Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance,
University of North Carolina at Chapel Hill
(Jan. 1969 to Aug. 1972)

Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics.

Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*

B.A., Economics,
Emory University, Atlanta, Georgia
(Sep. 1961 to Jun. 1965)

Active in extracurricular activities, President of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics in evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in over 250 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.
State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Kansas, Maryland, Michigan, Missouri, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 41 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (86 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; Appointed by Hays County Commission to Citizens Advisory Committee of Habitat Conservation Plan, Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas;* Appointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board Member, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering Support Unit; Officer-in-charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

Ethics and the Investment Professional (video, workbook, and instructor's guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success*, Association for Investment Management and Research (1994)

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"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

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"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"The Who, What, When, How, and Why of Ethics", San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

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"A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latané, American Finance Association, San Francisco (Dec. 1974)

"An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)

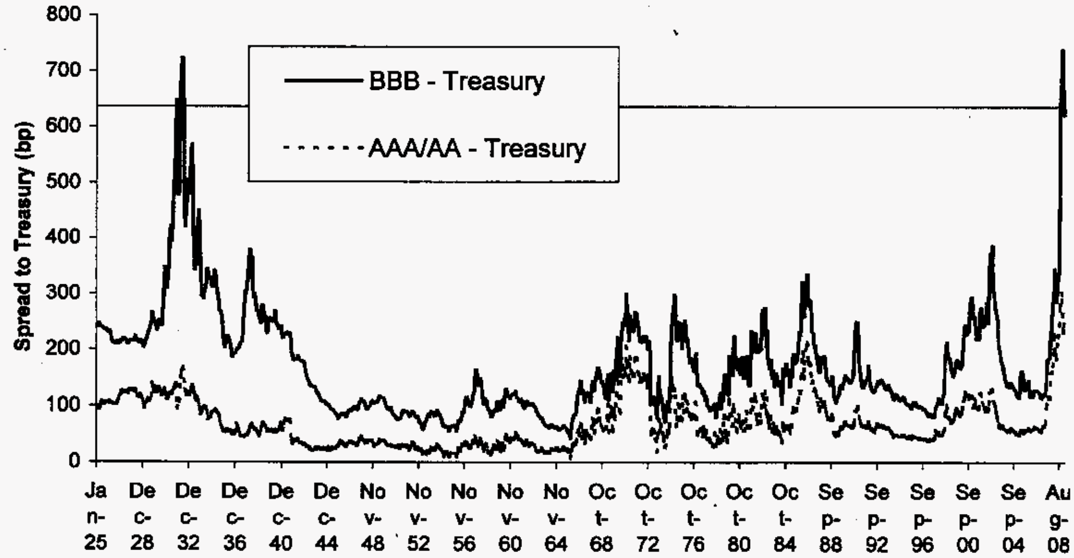
"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Multi-period Wealth Distributions and Portfolio Theory," Southern Finance Association, Houston (Nov. 1973)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

EXHIBIT WEA-2

YIELD SPREADS – CORPORATE BONDS V. TREASURIES



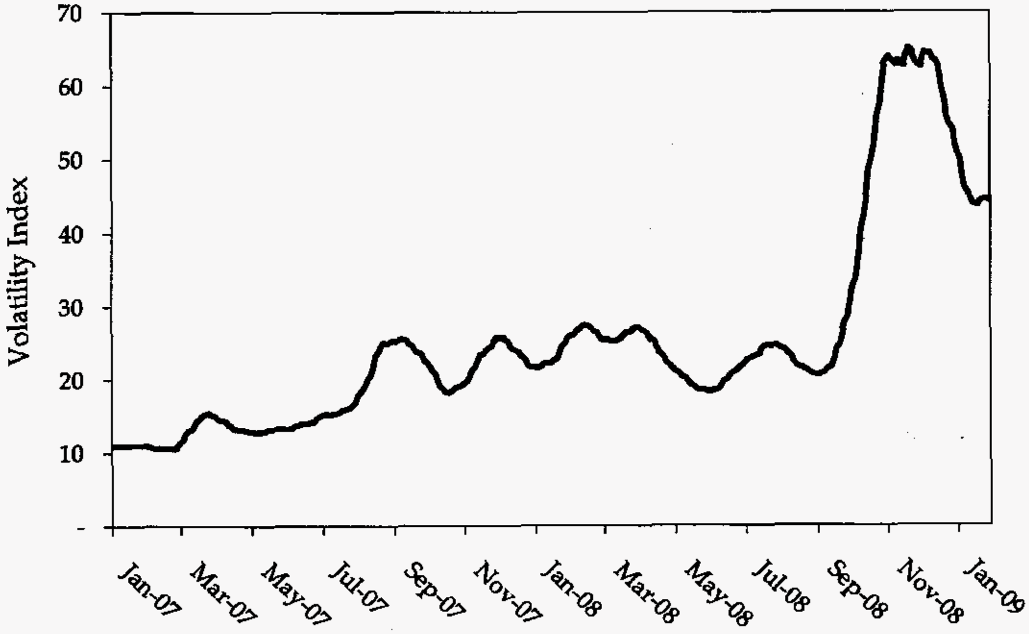
Source: Morgan Stanley Research, Moody's Investors Service.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 131
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS William E. Avera (WEA-2)
DATE 09/16/09

EXHIBIT WEA-3

CBOE VIX INDEX – ONE MONTH MOVING AVERAGE

(January 2005 –January 2009)



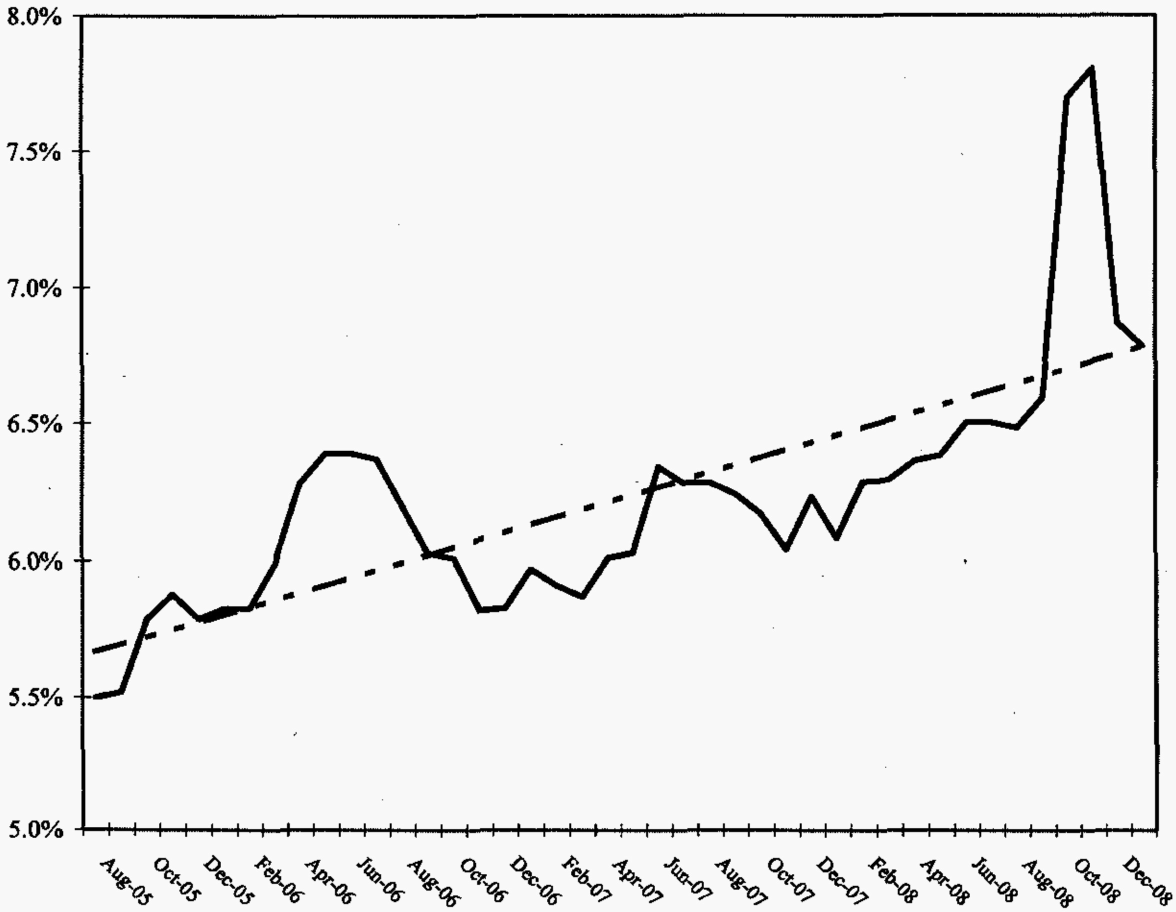
Source: http://www.cboe.com/micro/vix/historical.aspx.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 132
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS William E. Avera (WEA-3)
DATE 09/16/09

EXHIBIT WEA-4

AVERAGE PUBLIC UTILITY BOND YIELD

August 2005 – January 2009)

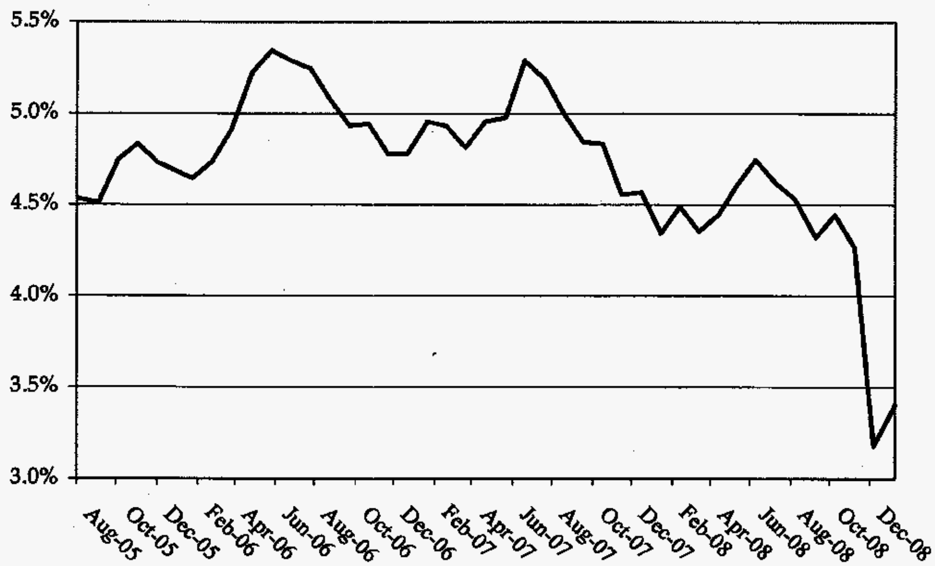


Source: Moody's Investors Service.

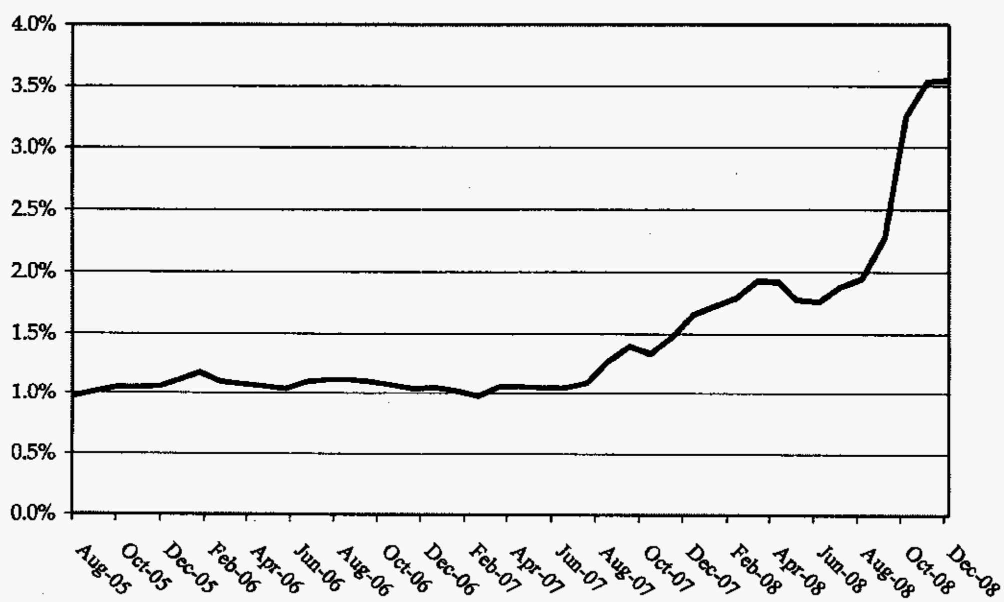
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 133
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS William E. Avera (WEA-4)
DATE 09/16/09

EXHIBIT WEA-5

20-YEAR TREASURY BOND YIELD



YIELD SPREAD – UTILITY BONDS V. 20-YEAR TREASURIES



Source: Federal Reserve, Moody's Investors Service.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 134
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS William E. Avera (WEA-5)
DATE 09/16/09

EXHIBIT WEA-6

COMPARISON OF PROXY GROUP RISK INDICATORS

Proxy Group	S&P Credit Rating	Value Line Safety Rank	Value Line Financial Strength	Value Line Beta
Utility	A-	2	A	0.73
Non-Utility	A+	1	A+	0.84
FPL	A	1	A+	0.80

Source: Standard & Poor's Corporation, The Value Line Investment Survey.

DCF MODEL

UTILITY PROXY GROUP

		(a)	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(g)	(g)	(g)	(g)
		Dividend Yield			**Growth Rates**					**Cost of Equity Estimates**				
	Company	**Price**	**Dividends**	**Yield**	**V Line**	**IBES**	**First Call**	**Zacks**	**br+sv**	**V Line**	**IBES**	**First Call**	**Zacks**	**br+sv**
1	ALLETE	$ 31.04	$ 1.76	5.7%	0.0%	6.5%	6.5%	5.0%	5.6%	5.7%	12.2%	12.2%	10.7%	11.3%
2	Alliant Energy	$ 30.64	$ 1.50	4.9%	6.0%	6.1%	6.1%	5.0%	4.8%	10.9%	11.0%	11.0%	9.9%	9.7%
3	Consolidated Edison	$ 39.35	$ 2.34	5.9%	1.0%	2.1%	2.0%	3.3%	2.5%	6.9%	8.0%	7.9%	9.2%	8.5%
4	Dominion Resources	$ 34.66	$ 1.75	5.0%	12.0%	8.2%	7.0%	7.2%	8.9%	17.0%	13.2%	12.0%	12.2%	14.0%
5	Duke Energy	$ 14.94	$ 0.94	6.3%	4.0%	4.5%	4.9%	5.0%	2.2%	10.3%	10.8%	11.2%	11.3%	8.5%
6	FPL Group, Inc.	$ 47.99	$ 1.88	3.9%	9.5%	9.7%	10.0%	9.3%	8.2%	13.4%	13.6%	13.9%	13.2%	12.1%
7	Integrys Energy Group	$ 42.56	$ 2.72	6.4%	6.0%	11.1%	11.1%	9.0%	4.1%	12.4%	17.5%	17.5%	15.4%	10.5%
8	MDU Resources Group	$ 22.31	$ 0.62	2.8%	7.0%	11.7%	9.0%	9.1%	9.2%	9.8%	14.4%	11.8%	11.9%	11.9%
9	NSTAR	$ 36.33	$ 1.50	4.1%	7.5%	6.7%	6.0%	6.8%	5.6%	11.6%	10.8%	10.1%	10.9%	9.8%
10	OGE Energy Corp.	$ 26.10	$ 1.43	5.5%	4.5%	6.0%	6.0%	NA	6.8%	10.0%	11.5%	11.5%	NA	12.3%
11	PG&E Corp.	$ 38.51	$ 1.62	4.2%	5.0%	7.0%	7.2%	7.5%	5.4%	9.2%	11.2%	11.4%	11.7%	9.6%
12	Portland General Elec.	$ 18.40	$ 1.00	5.4%	7.0%	5.9%	5.3%	6.5%	4.8%	12.4%	11.4%	10.7%	11.9%	10.3%
13	Progress Energy	$ 40.34	$ 2.48	6.1%	5.0%	6.0%	5.0%	5.0%	2.7%	11.1%	12.1%	11.1%	11.1%	8.8%
14	SCANA Corp.	$ 34.81	$ 1.92	5.5%	4.5%	5.0%	5.0%	5.0%	5.8%	10.0%	10.5%	10.5%	10.5%	11.3%
15	Sempra Energy	$ 41.85	$ 1.55	3.7%	7.0%	7.0%	6.7%	7.0%	7.4%	10.7%	10.7%	10.4%	10.7%	11.1%
16	Southern Company	$ 37.20	$ 1.73	4.7%	5.5%	5.6%	5.8%	5.2%	6.0%	10.2%	10.2%	10.5%	9.9%	10.6%
17	Vectren Corp.	$ 26.19	$ 1.34	5.1%	5.0%	5.7%	6.0%	6.4%	5.2%	10.1%	10.8%	11.1%	11.5%	10.3%
18	Wisconsin Energy	$ 42.96	$ 1.35	3.1%	8.0%	9.4%	9.9%	9.0%	6.7%	11.1%	12.5%	13.0%	12.1%	9.9%
19	Xcel Energy, Inc.	$ 18.54	$ 0.97	5.2%	7.5%	6.9%	7.0%	6.5%	5.7%	12.7%	12.1%	12.2%	11.7%	10.9%
	Average (h)									**11.0%**	**11.5%**	**11.3%**	**11.4%**	**10.6%**

(a) Recent price and estimated dividend for next 12 mos. from The Value Line Investment Survey, *Summary and Index* (Dec. 26, 2008)
(b) The Value Line Investment Survey (Nov. 7, Nov. 28, & Dec. 26, 2008).
(c) Thomson Reuters, *Company in Context Report* (Jan. 7, 2009).
(d) *First Call Earnings Valuation Report* (Jan. 5, 2009)
(e) www.zacks.com (retrieved Jan. 5, 2009).
(f) See Exhibit WEA-8.
(g) Sum of dividend yield and respective growth rate.
(h) Excludes highlighted figures.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. ______ EXHIBIT 136
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS William E. Avera (WEA-7)
DATE 09/16/09

SUSTAINABLE GROWTH RATE

UTILITY PROXY GROUP

		(a)	(a)	(b)	(a)	(a)	(a)	(c)	(d)
		2011-13 Market Price			2011-13 Projections				
	Company	High	Low	Avg.	EPS	DPS	BVPS	b	r
1	ALLETE	50.00	35.00	$42.50	$2.75	$1.90	$28.50	30.9%	9.6%
2	Alliant Energy	50.00	35.00	$42.50	$3.30	$1.92	$31.50	41.8%	10.5%
3	Consolidated Edison	50.00	40.00	$45.00	$3.30	$2.42	$37.70	26.7%	8.8%
4	Dominion Resources	60.00	45.00	$52.50	$4.00	$2.15	$26.75	46.3%	15.0%
5	Duke Energy	25.00	19.00	$22.00	$1.45	$1.06	$18.50	26.9%	7.8%
6	FPL Group, Inc.	80.00	65.00	$72.50	$5.00	$2.20	$37.50	56.0%	13.3%
7	Integrys Energy Group	65.00	50.00	$57.50	$4.75	$2.84	$49.00	40.2%	9.7%
8	MDU Resources Group	35.00	30.00	$32.50	$2.50	$0.76	$21.25	69.6%	11.8%
9	NSTAR	45.00	40.00	$42.50	$3.00	$1.85	$21.00	38.3%	14.3%
10	OGE Energy Corp.	45.00	30.00	$37.50	$3.00	$1.60	$25.50	46.7%	11.8%
11	PG&E Corp.	45.00	35.00	$40.00	$3.50	$2.04	$29.95	41.7%	11.7%
12	Portland General Elec.	30.00	25.00	$27.50	$2.25	$1.20	$25.00	46.7%	9.0%
13	Progress Energy	50.00	35.00	$42.50	$3.40	$2.54	$36.45	25.3%	9.3%
14	SCANA Corp.	55.00	40.00	$47.50	$3.50	$2.10	$32.75	40.0%	10.7%
15	Sempra Energy	90.00	70.00	$80.00	$6.00	$2.00	$45.75	66.7%	13.1%
16	Southern Company	45.00	35.00	$40.00	$3.00	$2.00	$21.50	33.3%	14.0%
17	Vectren Corp.	40.00	30.00	$35.00	$2.25	$1.47	$19.55	34.7%	11.5%
18	Wisconsin Energy	65.00	50.00	$57.50	$4.25	$1.95	$35.25	54.1%	12.1%
19	Xcel Energy, Inc.	25.00	19.00	$22.00	$2.00	$1.06	$18.00	47.0%	11.1%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 137
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS William E. Avera (WEA-8)
DATE 09/16/09

SUSTAINABLE GROWTH RATE

UTILITY PROXY GROUP

		(a)	(a)	(e)	(a)	(a)	(e)	(f)	(g)	(h)
		2007			2011-13			Adjusted "r"		
	Company	BVPS	No. Shares	Common Equity	BVPS	No. Shares	Common Equity	Chg in Equity	Adj. Factor	Adj. r
1	ALLETE	$24.11	30.80	$743	$28.50	39.50	$1,126	8.7%	1.0416	10.1%
2	Alliant Energy	$24.30	110.36	$2,682	$31.50	115.00	$3,623	6.2%	1.0301	10.8%
3	Consolidated Edison	$32.58	272.02	$8,862	$37.70	284.00	$10,707	3.9%	1.0189	8.9%
4	Dominion Resources	$16.30	577.00	$9,405	$26.75	627.00	$16,772	12.3%	1.0578	15.8%
5	Duke Energy	$16.80	1,262.00	$21,202	$18.50	1,300.00	$24,050	2.6%	1.0126	7.9%
6	FPL Group, Inc.	$26.35	407.35	$10,734	$37.50	418.00	$15,675	7.9%	1.0379	13.8%
7	Integrys Energy Group	$42.58	75.99	$3,236	$49.00	78.50	$3,847	3.5%	1.0173	9.9%
8	MDU Resources Group	$13.75	182.95	$2,516	$21.25	193.00	$4,101	10.3%	1.0488	12.3%
9	NSTAR	$15.95	106.81	$1,704	$21.00	106.81	$2,243	5.7%	1.0275	14.7%
10	OGE Energy Corp.	$18.31	91.80	$1,681	$25.50	103.00	$2,627	9.3%	1.0446	12.3%
11	PG&E Corp.	$22.60	378.39	$8,552	$29.95	398.00	$11,920	6.9%	1.0332	12.1%
12	Portland General Elec.	$21.05	62.53	$1,316	$25.00	79.00	$1,975	8.5%	1.0406	9.4%
13	Progress Energy	$32.38	260.10	$8,422	$36.45	280.00	$10,206	3.9%	1.0192	9.5%
14	SCANA Corp.	$25.30	117.00	$2,960	$32.75	135.00	$4,421	8.4%	1.0401	11.1%
15	Sempra Energy	$31.87	261.21	$8,325	$45.75	235.00	$10,751	5.2%	1.0256	13.5%
16	Southern Company	$16.23	763.10	$12,385	$21.50	815.00	$17,523	7.2%	1.0347	14.4%
17	Vectren Corp.	$16.16	76.36	$1,234	$19.55	81.80	$1,599	5.3%	1.0259	11.8%
18	Wisconsin Energy	$26.50	116.94	$3,099	$35.25	117.00	$4,124	5.9%	1.0286	12.4%
19	Xcel Energy, Inc.	$14.70	428.78	$6,303	$18.00	458.00	$8,244	5.5%	1.0268	11.4%

SUSTAINABLE GROWTH RATE

Docket No. 080677-EI
Sustainable Growth Rate – Utility Proxy Group
Exhibit WEA-8, Page 3 of 3

UTILITY PROXY GROUP

		(a)	(a)	(f)	(i)	(j)	(k)	(l)	(m)
		Common Shares Outstanding			M/B	"sv" Factor			
	Company	2007	2011-13	Change	Ratio	s	v	sv	br + sv
1	ALLETE	30.8	39.5	5.10%	1.49	0.0761	0.3294	2.51%	5.6%
2	Alliant Energy	110.4	115.0	0.83%	1.35	0.0112	0.2588	0.29%	4.8%
3	Consolidated Edison	272.0	284.0	0.87%	1.19	0.0103	0.1622	0.17%	2.5%
4	Dominion Resources	577.0	627.0	1.68%	1.96	0.0329	0.4905	1.61%	8.9%
5	Duke Energy	1,262.0	1,300.0	0.60%	1.19	0.0071	0.1591	0.11%	2.2%
6	FPL Group, Inc.	407.4	418.0	0.52%	1.93	0.0100	0.4828	0.48%	8.2%
7	Integrys Energy Group	76.0	78.5	0.65%	1.17	0.0077	0.1478	0.11%	4.1%
8	MDU Resources Group	183.0	193.0	1.08%	1.53	0.0164	0.3462	0.57%	9.2%
9	NSTAR	106.8	106.8	0.00%	2.02	-	0.5059	0.00%	5.6%
10	OGE Energy Corp.	91.8	103.0	2.33%	1.47	0.0343	0.3200	1.10%	6.8%
11	PG&E Corp.	378.4	398.0	1.02%	1.34	0.0136	0.2513	0.34%	5.4%
12	Portland General Elec.	62.5	79.0	4.79%	1.10	0.0527	0.0909	0.48%	4.8%
13	Progress Energy	260.1	280.0	1.49%	1.17	0.0173	0.1424	0.25%	2.7%
14	SCANA Corp.	117.0	135.0	2.90%	1.45	0.0421	0.3105	1.31%	5.8%
15	Sempra Energy	261.2	235.0	-2.09%	1.75	(0.0366)	0.4281	-1.57%	7.4%
16	Southern Company	763.1	815.0	1.32%	1.86	0.0246	0.4625	1.14%	6.0%
17	Vectren Corp.	76.4	81.8	1.39%	1.79	0.0248	0.4414	1.10%	5.2%
18	Wisconsin Energy	116.9	117.0	0.01%	1.63	0.0002	0.3870	0.01%	6.7%
19	Xcel Energy, Inc.	428.8	458.0	1.33%	1.22	0.0162	0.1818	0.29%	5.7%

(a) The Value Line Investment Survey (Nov. 7, Nov. 28, & Dec. 26, 2008).
(b) Average of High and Low expected market prices.
(c) Computed at (EPS - DPS) / EPS.
(d) Computed as EPS / BVPS.
(e) Product of BVPS and No. Shares Outstanding.
(f) Five-year rate of change.
(g) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(h) Product of year-end "r" for 2011-13 and Adjustment Factor.
(i) Average of High and Low expected market prices divided by 2011-13 BVPS.
(j) Product of change in common shares outstanding and M/B Ratio.
(k) Computed as 1 - B/M Ratio.
(l) Product of "s" and "v".
(m) Product of average "b" and adjusted "r", plus "sv".

		(a)	(a)	(b)	(c)	(d)	(e)	(f)	(f)	(f)	(f)	(f)
		Dividend	Growth Rates					Cost of Equity Estimates				
	Company	Yield	V Line	IBES	First Call	Zacks	br+sv	V Line	IBES	First Call	Zacks	br+sv
1	3M Company	3.38%	4.0%	11.3%	11.0%	10.3%	16.0%	7.4%	14.7%	14.4%	13.7%	19.4%
2	Abbott Labs.	2.77%	11.5%	11.9%	13.0%	11.8%	13.3%	14.3%	14.7%	15.8%	14.6%	16.1%
3	Aflac Inc.	2.30%	14.5%	15.0%	15.0%	15.2%	10.7%	16.8%	17.3%	17.3%	17.5%	13.0%
4	Allergan, Inc.	0.55%	15.5%	14.4%	15.0%	14.9%	15.4%	16.1%	15.0%	15.6%	15.5%	15.9%
5	Allstate Corp.	6.80%	7.5%	7.0%	8.0%	8.6%	10.0%	14.3%	13.8%	14.8%	15.4%	16.8%
6	AT&T Inc.	5.68%	12.0%	6.5%	6.5%	17.9%	4.1%	17.7%	12.2%	12.2%	23.6%	9.8%
7	Bard (C.R.)	0.78%	13.5%	14.3%	14.0%	14.0%	13.1%	14.3%	15.0%	14.8%	14.8%	13.9%
8	Baxter Int'l Inc.	1.67%	16.5%	12.4%	12.9%	13.6%	14.1%	18.2%	14.1%	14.6%	15.3%	15.7%
9	Becton, Dickinson	1.82%	11.5%	12.5%	12.0%	12.3%	14.0%	13.3%	14.3%	13.8%	14.1%	15.8%
10	Bemis Co.	3.49%	5.0%	9.3%	9.0%	10.5%	6.0%	8.5%	12.8%	12.5%	14.0%	9.4%
11	Boeing	4.08%	15.5%	11.4%	10.0%	9.4%	16.6%	19.6%	15.5%	14.1%	13.5%	20.7%
12	Brown-Forman 'B'	2.48%	7.5%	8.4%	7.3%	10.5%	11.9%	10.0%	10.9%	9.8%	13.0%	14.4%
13	Chevron Corp.	3.62%	8.5%	3.0%	7.3%	10.3%	13.2%	12.1%	6.7%	10.9%	13.9%	16.8%
14	Chubb Corp.	2.76%	2.0%	10.0%	10.0%	9.3%	5.8%	4.8%	12.8%	12.8%	12.1%	8.5%
15	Coca-Cola	3.40%	8.5%	8.6%	8.5%	8.7%	11.0%	11.9%	12.0%	11.9%	12.1%	14.4%
16	Colgate-Palmolive	2.59%	12.0%	10.4%	11.0%	10.0%	18.9%	14.6%	13.0%	13.6%	12.6%	21.5%
17	Commerce Bancshs.	2.51%	4.5%	6.2%	5.7%	6.5%	8.7%	7.0%	8.7%	8.2%	9.0%	11.2%
18	ConocoPhillips	4.06%	6.5%	-0.6%	5.7%	9.2%	15.8%	10.6%	3.5%	9.8%	13.3%	19.9%
19	Du Pont	6.92%	6.5%	3.1%	5.3%	9.5%	9.3%	13.4%	10.1%	12.2%	16.4%	16.3%
20	Eaton Corp.	4.81%	11.5%	9.4%	11.0%	11.5%	15.8%	16.3%	14.2%	15.8%	16.3%	20.6%
21	Ecolab Inc.	1.47%	13.0%	12.8%	13.0%	13.5%	15.4%	14.5%	14.3%	14.5%	15.0%	16.9%
22	Emerson Electric	4.18%	11.0%	12.3%	12.0%	11.8%	7.2%	15.2%	16.5%	16.2%	16.0%	11.4%
23	Everest Re Group Ltd.	2.59%	14.5%	10.0%	10.0%	15.0%	10.6%	17.1%	12.6%	12.6%	17.6%	13.2%
24	Exxon Mobil Corp.	2.10%	8.5%	2.3%	6.6%	8.6%	12.9%	10.6%	4.4%	8.7%	10.7%	15.0%
25	Fortune Brands	4.67%	5.5%	10.0%	10.0%	9.4%	8.6%	10.2%	14.7%	14.7%	14.1%	13.2%
26	Gallagher (Arthur J.)	5.35%	5.5%	6.0%	6.0%	9.5%	9.3%	10.9%	11.4%	11.4%	14.9%	14.6%
27	Gen'l Dynamics	2.80%	12.0%	9.0%	10.0%	9.1%	10.7%	14.8%	11.8%	12.8%	11.9%	13.5%
28	Gen'l Mills	2.79%	10.0%	10.0%	10.0%	9.0%	8.4%	12.8%	12.8%	12.8%	11.8%	11.2%
29	Genuine Parts	4.22%	9.0%	8.3%	8.0%	9.0%	6.5%	13.2%	12.5%	12.2%	13.2%	10.7%
30	Grainger (W.W.)	2.38%	12.5%	11.7%	12.0%	11.3%	8.7%	14.9%	14.1%	14.4%	13.7%	11.0%
31	Heinz (H.J.)	4.52%	10.0%	7.0%	7.0%	NA	13.6%	14.5%	11.5%	11.5%	NA	18.2%
32	Hewlett-Packard	0.96%	17.5%	12.7%	12.0%	12.5%	10.3%	18.5%	13.6%	13.0%	13.5%	11.3%
33	Home Depot	3.88%	-0.5%	9.8%	11.0%	9.3%	8.2%	3.4%	13.6%	14.9%	13.2%	12.1%
34	Honeywell Int'l	4.32%	13.0%	10.0%	11.0%	11.8%	14.0%	17.3%	14.3%	15.3%	16.1%	18.4%
35	Hormel Foods	2.81%	11.0%	8.8%	8.5%	8.4%	11.3%	13.8%	11.6%	11.3%	11.2%	14.1%
36	Illinois Tool Works	3.90%	10.5%	10.1%	10.0%	9.4%	10.8%	14.4%	14.0%	13.9%	13.3%	14.7%
37	Ingersoll-Rand	4.93%	18.5%	12.0%	12.0%	12.3%	18.0%	23.4%	16.9%	16.9%	17.2%	22.9%
38	Int'l Business Mach.	2.58%	14.5%	11.0%	10.0%	10.5%	7.4%	17.1%	13.6%	12.6%	13.1%	10.0%
39	ITT Corp.	1.71%	14.0%	13.0%	13.0%	12.1%	13.1%	15.7%	14.7%	14.7%	13.8%	14.8%
40	Johnson & Johnson	3.28%	8.0%	7.8%	7.5%	7.8%	10.1%	11.3%	11.1%	10.8%	11.1%	13.4%
41	Kimberly-Clark	4.24%	7.0%	7.7%	7.0%	7.3%	12.9%	11.2%	11.9%	11.2%	11.5%	17.1%
42	Kraft Foods	4.44%	6.5%	9.3%	7.3%	8.0%	4.8%	10.9%	13.8%	11.7%	12.4%	9.2%
43	Lilly (Eli)	5.55%	4.5%	5.9%	5.0%	6.4%	8.6%	10.1%	11.5%	10.6%	12.0%	14.2%
44	Lincoln Nat'l Corp.	13.60%	9.5%	10.5%	11.2%	11.0%	8.4%	23.1%	24.1%	24.8%	24.6%	22.0%
45	Lockheed Martin	2.96%	15.5%	11.5%	10.0%	8.6%	13.2%	18.5%	14.5%	13.0%	11.6%	16.2%
46	Manulife Fin'l	6.78%	10.5%	12.8%	13.7%	11.0%	11.0%	17.3%	19.6%	20.5%	17.8%	17.8%
47	McDonald's Corp.	3.29%	12.0%	10.5%	9.0%	12.0%	2.3%	15.3%	13.8%	12.3%	15.3%	5.5%
48	Medtronic, Inc.	2.46%	11.0%	12.2%	12.0%	13.4%	9.2%	13.5%	14.7%	14.5%	15.9%	11.7%
49	Microsoft Corp.	2.72%	15.5%	10.9%	11.0%	11.0%	-1.2%	18.2%	13.6%	13.7%	13.7%	1.5%
50	NIKE, Inc. 'B'	1.77%	11.5%	13.0%	14.0%	12.3%	9.5%	13.3%	14.8%	15.8%	14.1%	11.3%
51	Northrop Grumman	4.08%	11.5%	12.8%	10.0%	9.6%	8.2%	15.6%	16.9%	14.1%	13.7%	12.2%
52	PepsiCo, Inc.	3.25%	11.0%	9.4%	9.8%	10.3%	10.3%	14.3%	12.7%	13.1%	13.6%	13.5%
53	Pfizer, Inc.	7.87%	0.5%	1.0%	3.0%	3.9%	6.9%	8.4%	8.9%	10.9%	11.8%	14.7%
54	Procter & Gamble	2.61%	9.0%	10.0%	10.0%	10.2%	6.5%	11.6%	12.6%	12.6%	12.8%	9.1%
55	Raytheon Co.	2.32%	14.0%	12.4%	10.0%	10.6%	8.6%	16.3%	14.7%	12.3%	12.9%	10.9%
56	Reinsurance Group	1.00%	11.5%	10.1%	10.5%	11.5%	11.3%	12.5%	11.1%	11.5%	12.5%	12.3%
57	Sigma-Aldrich	1.39%	9.5%	9.0%	9.1%	9.0%	13.4%	10.9%	10.4%	10.5%	10.4%	14.8%
58	Sysco Corp.	4.00%	12.0%	12.0%	12.0%	12.5%	8.8%	16.0%	16.0%	16.0%	16.5%	12.8%
59	Torchmark Corp.	1.62%	8.0%	8.3%	8.0%	NA	10.6%	9.6%	9.9%	9.6%	NA	12.2%
60	United Parcel Serv.	3.17%	7.0%	11.7%	11.5%	11.8%	14.0%	10.2%	14.8%	14.7%	15.0%	17.2%
61	United Technologies	3.27%	12.5%	10.0%	10.0%	9.6%	11.8%	15.8%	13.3%	13.3%	12.9%	15.0%
62	Verizon Communic.	5.72%	6.0%	6.6%	7.0%	7.4%	8.6%	11.7%	12.3%	12.7%	13.1%	14.3%
63	Wal-Mart Stores	1.72%	9.5%	11.5%	11.0%	10.2%	10.0%	11.2%	13.2%	12.7%	11.9%	11.7%
64	Walgreen Co.	1.84%	11.0%	12.6%	14.0%	13.6%	11.8%	12.8%	14.4%	15.8%	15.4%	13.6%
65	Wells Fargo	4.94%	5.5%	8.5%	8.5%	8.2%	11.7%	10.4%	13.4%	13.4%	13.1%	16.6%
66	Wyeth	3.57%	6.0%	2.1%	2.0%	4.7%	14.2%	9.6%	5.7%	5.6%	8.3%	17.8%
	Average (g)							**12.9%**	**13.3%**	**13.0%**	**13.4%**	**13.3%**

(a) www.valueline.com (retrieved Dec. 11, 2008).
(b) www.finance.yahoo.com (retrieved Dec. 16, 2008).
(c) *First Call Earnings Valuation Report* (retrieved Dec. 17, 2008).
(d) www.zacks.com (retrieved Dec. 16, 2008).
(e) See Exhibit WEA-10.
(f) Sum of dividend yield and respective growth rate.
(g) Excludes highlighted figures.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 138
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS William E. Avera (WEA-9)
DATE 09/16/09

		(a)	(a)	(b)	(a)	(a)	(a)	(c)	(d)
		2011-13 Market Price			2011-13 Projections				
	Company	High	Low	Avg.	EPS	DPS	BVPS	b	r
1	3M Company	$110.00	$90.00	$100.00	$6.25	$2.20	$21.85	64.8%	28.6%
2	Abbott Labs.	$100.00	$80.00	$90.00	$5.05	$2.10	$21.45	58.4%	23.5%
3	Aflac Inc.	$115.00	$95.00	$105.00	$6.45	$1.88	$30.70	70.9%	21.0%
4	Allergan, Inc.	$115.00	$95.00	$105.00	$4.05	$0.30	$29.50	92.6%	13.7%
5	Allstate Corp.	$90.00	$75.00	$82.50	$8.35	$2.25	$59.45	73.1%	14.0%
6	AT&T Inc.	$80.00	$65.00	$72.50	$4.50	$2.60	$25.80	42.2%	17.4%
7	Bard (C.R.)	$155.00	$130.00	$142.50	$7.15	$0.90	$31.78	87.4%	22.5%
8	Baxter Int'l Inc.	$105.00	$85.00	$95.00	$5.40	$1.55	$23.85	71.3%	22.6%
9	Becton, Dickinson	$115.00	$90.00	$102.50	$6.40	$1.75	$34.25	72.7%	18.7%
10	Bemis Co.	$45.00	$35.00	$40.00	$2.30	$1.04	$21.50	54.8%	10.7%
11	Boeing	$150.00	$120.00	$135.00	$9.00	$2.50	$37.35	72.2%	24.1%
12	Brown-Forman 'B'	$75.00	$60.00	$67.50	$4.00	$1.32	$20.70	67.0%	19.3%
13	Chevron Corp.	$140.00	$110.00	$125.00	$12.50	$3.20	$57.55	74.4%	21.7%
14	Chubb Corp.	$85.00	$70.00	$77.50	$6.30	$2.80	$56.25	55.6%	11.2%
15	Coca-Cola	$90.00	$75.00	$82.50	$3.85	$1.88	$17.30	51.2%	22.3%
16	Colgate-Palmolive	$140.00	$115.00	$127.50	$5.80	$2.30	$13.55	60.3%	42.8%
17	Commerce Bancshs.	$55.00	$45.00	$50.00	$3.70	$1.20	$33.35	67.6%	11.1%
18	ConocoPhillips	$145.00	$120.00	$132.50	$14.00	$2.00	$72.40	85.7%	19.3%
19	Du Pont	$80.00	$65.00	$72.50	$4.10	$1.92	$19.20	53.2%	21.4%
20	Eaton Corp.	$210.00	$170.00	$190.00	$11.90	$3.10	$55.90	73.9%	21.3%
21	Ecolab Inc.	$65.00	$55.00	$60.00	$3.00	$0.75	$15.10	75.0%	19.9%
22	Emerson Electric	$90.00	$75.00	$82.50	$4.15	$1.80	$15.80	56.6%	26.3%
23	Everest Re Group Ltd.	$165.00	$135.00	$150.00	$15.00	$2.35	$116.65	84.3%	12.9%
24	Exxon Mobil Corp.	$140.00	$115.00	$127.50	$10.50	$1.90	$38.55	81.9%	27.2%
25	Fortune Brands	$115.00	$95.00	$105.00	$7.00	$1.86	$55.15	73.4%	12.7%
26	Gallagher (Arthur J.)	$40.00	$35.00	$37.50	$2.20	$1.44	$10.35	34.5%	21.3%
27	Gen'l Dynamics	$140.00	$115.00	$127.50	$8.40	$2.25	$51.70	73.2%	16.2%
28	Gen'l Mills	$95.00	$80.00	$87.50	$5.10	$2.25	$23.50	55.9%	21.7%
29	Genuine Parts	$80.00	$65.00	$72.50	$4.65	$2.16	$24.65	53.5%	18.9%
30	Grainger (W.W.)	$160.00	$130.00	$145.00	$8.65	$2.35	$48.20	72.8%	17.9%
31	Heinz (H.J.)	$80.00	$65.00	$72.50	$4.30	$2.08	$12.25	51.6%	35.1%
32	Hewlett-Packard	$95.00	$80.00	$87.50	$5.50	$0.60	$23.75	89.1%	23.2%
33	Home Depot	$50.00	$40.00	$45.00	$2.50	$1.10	$17.25	56.0%	14.5%
34	Honeywell Int'l	$85.00	$70.00	$77.50	$5.35	$1.60	$25.95	70.1%	20.6%
35	Hormel Foods	$75.00	$60.00	$67.50	$3.75	$1.20	$23.35	68.0%	16.1%
36	Illinois Tool Works	$100.00	$80.00	$90.00	$5.50	$1.40	$24.30	74.5%	22.6%
37	Ingersoll-Rand	$70.00	$55.00	$62.50	$8.25	$1.00	$46.15	87.9%	17.9%
38	Int'l Business Mach.	$245.00	$200.00	$222.50	$14.00	$3.25	$27.35	76.8%	51.2%
39	ITT Corp.	$115.00	$95.00	$105.00	$6.60	$1.06	$42.50	83.9%	15.5%
40	Johnson & Johnson	$120.00	$95.00	$107.50	$6.00	$2.40	$26.25	60.0%	22.9%
41	Kimberly-Clark	$100.00	$80.00	$90.00	$6.00	$2.95	$19.00	50.8%	31.6%
42	Kraft Foods	$65.00	$50.00	$57.50	$2.75	$1.40	$26.20	49.1%	10.5%
43	Lilly (Eli)	$70.00	$55.00	$62.50	$4.15	$2.16	$21.45	48.0%	19.3%
44	Lincoln Nat'l Corp.	$120.00	$100.00	$110.00	$8.50	$1.98	$60.45	76.7%	14.1%
45	Lockheed Martin	$210.00	$170.00	$190.00	$12.70	$2.65	$46.75	79.1%	27.2%
46	Manulife Financial	$60.00	$50.00	$55.00	$4.00	$1.20	$23.15	70.0%	17.3%
47	McDonald's Corp.	$90.00	$70.00	$80.00	$4.70	$2.80	$16.50	40.4%	28.5%
48	Medtronic, Inc.	$95.00	$80.00	$87.50	$4.55	$1.08	$19.55	76.3%	23.3%
49	Microsoft Corp.	$60.00	$50.00	$55.00	$3.10	$0.80	$9.50	74.2%	32.6%
50	NIKE, Inc. 'B'	$110.00	$90.00	$100.00	$5.15	$1.50	$23.85	70.9%	21.6%
51	Northrop Grumman	$140.00	$115.00	$127.50	$8.35	$2.10	$71.00	74.9%	11.8%
52	PepsiCo, Inc.	$125.00	$100.00	$112.50	$5.60	$2.12	$15.95	62.1%	35.1%
53	Pfizer, Inc.	$25.00	$20.00	$22.50	$2.15	$1.40	$10.10	34.9%	21.3%
54	Procter & Gamble	$110.00	$90.00	$100.00	$4.75	$1.95	$32.30	58.9%	14.7%
55	Raytheon Co.	$95.00	$80.00	$87.50	$5.75	$1.75	$40.75	69.6%	14.1%
56	Reinsurance Group	$70.00	$55.00	$62.50	$8.85	$0.50	$75.35	94.4%	11.7%
57	Sigma-Aldrich	$70.00	$60.00	$65.00	$3.60	$0.70	$18.45	80.6%	19.5%
58	Sysco Corp.	$65.00	$55.00	$60.00	$2.80	$1.25	$7.70	55.4%	36.4%
59	Torchmark Corp.	$100.00	$85.00	$92.50	$8.00	$0.75	$56.00	90.6%	14.3%
60	United Parcel Serv.	$135.00	$110.00	$122.50	$5.65	$2.25	$16.90	60.2%	33.4%
61	United Technologies	$130.00	$105.00	$117.50	$7.40	$1.85	$42.50	75.0%	17.4%
62	Verizon Communic.	$65.00	$55.00	$60.00	$3.50	$1.84	$18.75	47.4%	18.7%
63	Wal-Mart Stores	$90.00	$75.00	$82.50	$5.05	$1.25	$24.55	75.2%	20.6%
64	Walgreen Co.	$75.00	$65.00	$70.00	$3.25	$0.70	$21.65	78.5%	15.0%
65	Wells Fargo	$50.00	$40.00	$45.00	$3.25	$1.60	$19.20	50.8%	16.9%
66	Wyeth	$75.00	$60.00	$67.50	$4.60	$1.35	$24.25	70.7%	19.0%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 139
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS William E. Avera (WEA-10)
DATE 09/16/09

		(a)	(a)	(e)	(a)	(a)	(e)	(f)	(g)	(h)
			2007			2011-13			Adjusted "r"	
	Company	BVPS	No. Shares	Common Equity	BVPS	No. Shares	Common Equity	Chg in Equity	Adj. Factor	Adj. r
1	3M Company	$16.56	709.16	$11,744	$21.85	680.00	$14,858	4.8%	1.0235	29.3%
2	Abbott Labs.	$11.47	1549.90	$17,777	$21.45	1520.00	$32,604	12.9%	1.0606	25.0%
3	Aflac Inc.	$18.08	486.53	$8,796	$30.70	440.00	$13,508	9.0%	1.0429	21.9%
4	Allergan, Inc.	$12.22	305.91	$3,738	$29.50	315.00	$9,293	20.0%	1.0908	15.0%
5	Allstate Corp.	$38.81	563.00	$21,850	$59.45	520.00	$30,914	7.2%	1.0347	14.5%
6	AT&T Inc.	$19.09	6043.50	$115,370	$25.80	5500.00	$141,900	4.2%	1.0207	17.8%
7	Bard (C.R.)	$18.44	100.19	$1,848	$31.78	90.00	$2,860	9.1%	1.0437	23.5%
8	Baxter Int'l Inc.	$10.91	633.64	$6,913	$23.85	600.00	$14,310	15.7%	1.0726	24.3%
9	Becton, Dickinson	$17.89	243.84	$4,362	$34.25	241.00	$8,254	13.6%	1.0637	19.9%
10	Bemis Co.	$15.54	100.52	$1,562	$21.50	100.00	$2,150	6.6%	1.0319	11.0%
11	Boeing	$12.22	736.68	$9,002	$37.35	700.00	$26,145	23.8%	1.1062	26.7%
12	Boeing	$11.44	150.74	$1,724	$20.70	145.00	$3,002	11.7%	1.0554	20.4%
13	Chevron Corp.	$36.88	2090.40	$77,094	$57.55	1800.00	$103,590	6.1%	1.0295	22.4%
14	Chubb Corp.	$38.56	374.65	$14,447	$56.25	345.00	$19,406	6.1%	1.0295	11.5%
15	Coca-Cola	$9.38	2318.00	$21,743	$17.30	2285.00	$39,531	12.7%	1.0597	23.6%
16	Colgate-Palmolive	$4.10	509.03	$2,087	$13.55	480.00	$6,504	25.5%	1.1132	47.6%
17	Commerce Bancshs.	$21.25	71.89	$1,528	$33.35	78.00	$2,601	11.2%	1.0532	1.0532
18	Du Pont	$56.63	1571.40	$88,988	$72.40	1475.00	$106,790	3.7%	1.0182	19.7%
19	Du Pont	$12.38	899.30	$11,133	$19.20	860.00	$16,512	8.2%	1.0394	22.2%
20	Eaton Corp.	$35.42	146.00	$5,171	$55.90	144.00	$8,050	9.3%	1.0442	22.2%
21	Ecolab Inc.	$7.84	246.80	$1,935	$15.10	245.00	$3,700	13.8%	1.0647	21.2%
22	Emerson Electric	$11.14	787.23	$8,770	$15.80	715.00	$11,297	5.2%	1.0253	26.9%
23	Everest Re Group Ltd.	$86.92	65.40	$5,685	$116.65	60.00	$6,999	4.2%	1.0208	13.1%
24	Exxon Mobil Corp.	$22.62	5382.00	$121,741	$38.55	4300.00	$165,765	6.4%	1.0309	28.1%
25	Fortune Brands	$36.94	153.91	$5,685	$55.15	145.00	$7,997	7.1%	1.0341	13.1%
26	Gallagher (Arthur J.)	$7.78	92.00	$716	$10.35	95.00	$983	6.6%	1.0317	21.9%
27	Gen'l Dynamics	$29.13	403.98	$11,768	$51.70	380.00	$19,646	10.8%	1.0512	17.1%
28	Gen'l Mills	$15.64	340.00	$5,318	$23.50	315.00	$7,403	6.8%	1.0331	22.4%
29	Genuine Parts	$16.36	166.07	$2,717	$24.65	150.00	$3,698	6.4%	1.0308	19.4%
30	Grainger (W.W.)	$26.40	79.46	$2,098	$48.20	70.00	$3,374	10.0%	1.0475	18.8%
31	Heinz (H.J.)	$6.04	312.56	$1,888	$12.25	295.00	$3,614	13.9%	1.0648	37.4%
32	Hewlett-Packard	$14.93	2580.00	$38,519	$23.75	2100.00	$49,875	5.3%	1.0258	23.8%
33	Home Depot	$10.48	1690.00	$17,711	$17.25	1675.00	$28,894	10.3%	1.0489	15.2%
34	Honeywell Int'l	$12.35	746.55	$9,220	$25.95	720.00	$18,684	15.2%	1.0705	22.1%
35	Hormel Foods	$13.89	135.68	$1,885	$23.35	135.00	$3,152	10.8%	1.0514	16.9%
36	Illinois Tool Works	$17.64	530.10	$9,351	$24.30	470.00	$11,421	4.1%	1.0200	23.1%
37	Ingersoll-Rand	$29.01	272.61	$7,908	$46.15	325.00	$14,999	13.7%	1.0639	19.0%
38	Int'l Business Mach.	$20.55	1385.20	$28,466	$27.35	1100.00	$30,085	1.1%	1.0055	51.5%
39	ITT Corp.	$21.73	181.57	$3,946	$42.50	177.00	$7,523	13.8%	1.0644	16.5%
40	Johnson & Johnson	$15.25	2840.20	$43,313	$26.25	2650.00	$69,563	9.9%	1.0473	23.9%
41	Kimberly-Clark	$12.41	420.90	$5,223	$19.00	400.00	$7,600	7.8%	1.0375	32.8%
42	Kraft Foods	$17.80	1533.80	$27,302	$26.20	1500.00	$39,300	7.6%	1.0364	10.9%
43	Lilly (Eli)	$12.05	1134.30	$13,668	$21.45	1100.00	$23,595	11.5%	1.0545	20.4%
44	Lincoln Nat'l Corp.	$44.35	264.23	$11,719	$60.45	225.00	$13,601	3.0%	1.0149	14.3%
45	Lockheed Martin	$23.97	409.00	$9,804	$46.75	350.00	$16,363	10.8%	1.0512	28.6%
46	M&T Bank Corp.	$16.37	1501.00	$24,571	$23.15	1425.00	$32,989	6.1%	1.0294	17.8%
47	McDonald's Corp.	$13.11	1165.30	$15,277	$16.50	1030.00	$16,995	2.2%	1.0107	28.8%
48	Medtronic, Inc.	$10.25	1124.90	$11,530	$19.55	980.00	$19,159	10.7%	1.0507	24.5%
49	Microsoft Corp.	$3.32	9380.00	$31,142	$9.50	7000.00	$66,500	16.4%	1.0757	35.1%
50	NIKE, Inc. 'B'	$13.94	503.80	$7,023	$23.85	455.00	$10,852	9.1%	1.0435	22.5%
51	Northrop Grumman	$52.35	337.83	$17,685	$71.00	320.00	$22,720	5.1%	1.0250	12.1%
52	PepsiCo, Inc.	$10.71	1605.00	$17,190	$15.95	1450.00	$23,128	6.1%	1.0297	36.2%
53	Pfizer, Inc.	$9.60	6761.00	$64,906	$10.10	6600.00	$66,660	0.5%	1.0027	21.3%
54	Procter & Gamble	$20.87	3131.90	$65,363	$32.30	2950.00	$95,285	7.8%	1.0377	15.3%
55	Raytheon Co.	$29.43	426.20	$12,543	$40.75	400.00	$16,300	5.4%	1.0262	14.5%
56	Raytheon Co.	$51.42	62.03	$3,190	$75.35	67.00	$5,048	9.6%	1.0459	12.3%
57	Sigma-Aldrich	$12.21	132.41	$1,617	$18.45	125.00	$2,306	7.4%	1.0355	20.2%
58	Sysco Corp.	$5.36	611.84	$3,279	$7.70	560.00	$4,312	5.6%	1.0274	37.4%
59	Sysco Corp.	$36.07	92.18	$3,325	$56.00	75.00	$4,200	4.8%	1.0234	14.6%
60	United Parcel Serv.	$11.78	1034.40	$12,185	$16.90	980.00	$16,562	6.3%	1.0307	34.5%
61	United Technologies	$21.76	981.52	$21,358	$42.50	925.00	$39,313	13.0%	1.0609	18.5%
62	Verizon Communic.	$17.62	2871.00	$50,587	$18.75	2850.00	$53,438	1.1%	1.0055	18.8%
63	Wal-Mart Stores	$16.26	3973.00	$64,601	$24.55	3500.00	$85,925	5.9%	1.0285	21.2%
64	Walgreen Co.	$11.20	991.14	$11,101	$21.65	975.00	$21,109	13.7%	1.0642	16.0%
65	Wells Fargo	$14.31	3297.10	$47,182	$19.20	3650.00	$70,080	8.2%	1.0395	17.6%
66	Wyeth	$13.61	1337.80	$18,207	$24.25	1340.00	$32,495	12.3%	1.0579	20.1%

		(a)	(a)	(f)	(i)	(j)	(k)	(l)	(m)
		Common Shares Outstanding			M/B	"sv" Factor			
	Company	2007	2011-13	Change	Ratio	s	v	sv	br + sv
1	3M Company	709.16	680.00	-0.84%	4.58	(0.0383)	0.7815	-2.99%	16.0%
2	Abbott Labs.	1549.90	1520.00	-0.39%	4.20	(0.0163)	0.7617	-1.24%	13.3%
3	Aflac Inc.	486.53	440.00	-1.99%	3.42	(0.0681)	0.7076	-4.82%	10.7%
4	Allergan, Inc.	305.91	315.00	0.59%	3.56	0.0209	0.7190	1.50%	15.4%
5	Allstate Corp.	563.00	520.00	-1.58%	1.39	(0.0219)	0.2794	-0.61%	10.0%
6	AT&T Inc.	6043.50	5500.00	-1.87%	2.81	(0.0525)	0.6441	-3.38%	4.1%
7	Bard (C.R.)	100.19	90.00	-2.12%	4.48	(0.0952)	0.7770	-7.39%	13.1%
8	Baxter Int'l Inc.	633.64	600.00	-1.09%	3.98	(0.0432)	0.7489	-3.24%	14.1%
9	Becton, Dickinson	243.84	241.00	-0.23%	2.99	(0.0070)	0.6659	-0.47%	14.0%
10	Bemis Co.	100.52	100.00	-0.10%	1.86	(0.0019)	0.4625	-0.09%	6.0%
11	Boeing	736.68	700.00	-1.02%	3.61	(0.0367)	0.7233	-2.66%	16.6%
12	Boeing	150.74	145.00	-0.77%	3.26	(0.0252)	0.6933	-1.75%	11.9%
13	Chevron Corp.	2090.40	1800.00	-2.95%	2.17	(0.0640)	0.5396	-3.45%	13.2%
14	Chubb Corp.	374.65	345.00	-1.64%	1.38	(0.0225)	0.2742	-0.62%	5.8%
15	Coca-Cola	2318.00	2285.00	-0.29%	4.77	(0.0137)	0.7903	-1.08%	11.0%
16	Colgate-Palmolive	509.03	480.00	-1.17%	9.41	(0.1099)	0.8937	-9.82%	18.9%
17	Commerce Bancshs.	71.89	78.00	1.64%	1.50	0.0247	0.3330	0.82%	8.7%
18	Du Pont	1571.40	1475.00	-1.26%	1.83	(0.0230)	0.4536	-1.04%	15.8%
19	Du Pont	899.30	860.00	-0.89%	3.78	(0.0336)	0.7352	-2.47%	9.3%
20	Eaton Corp.	146.00	144.00	-0.28%	3.40	(0.0094)	0.7058	-0.66%	15.8%
21	Ecolab Inc.	246.80	245.00	-0.15%	3.97	(0.0058)	0.7483	-0.44%	15.4%
22	Emerson Electric	787.23	715.00	-1.91%	5.22	(0.0995)	0.8085	-8.05%	7.2%
23	Everest Re Group Ltd.	65.40	60.00	-1.71%	1.29	(0.0220)	0.2223	-0.49%	10.6%
24	Exxon Mobil Corp.	5382.00	4300.00	-4.39%	3.31	(0.1452)	0.6976	-10.13%	12.9%
25	Fortune Brands	153.91	145.00	-1.19%	1.90	(0.0226)	0.4748	-1.07%	8.6%
26	Gallagher (Arthur J.)	92.00	95.00	0.64%	3.62	0.0233	0.7240	1.69%	9.3%
27	Gen'l Dynamics	403.98	380.00	-1.22%	2.47	(0.0300)	0.5945	-1.78%	10.7%
28	Gen'l Mills	340.00	315.00	-1.52%	3.72	(0.0564)	0.7314	-4.13%	8.4%
29	Genuine Parts	166.07	150.00	-2.01%	2.94	(0.0593)	0.6600	-3.91%	6.5%
30	Grainger (W.W.)	79.46	70.00	-2.50%	3.01	(0.0753)	0.6676	-5.03%	8.7%
31	Heinz (H.J.)	312.56	295.00	-1.15%	5.92	(0.0680)	0.8310	-5.65%	13.6%
32	Hewlett-Packard	2580.00	2100.00	-4.03%	3.68	(0.1486)	0.7286	-10.83%	10.3%
33	Home Depot	1690.00	1675.00	-0.18%	2.61	(0.0046)	0.6167	-0.29%	8.2%
34	Honeywell Int'l	746.55	720.00	-0.72%	2.99	(0.0216)	0.6652	-1.43%	14.0%
35	Hormel Foods	135.68	135.00	-0.10%	2.89	(0.0029)	0.6541	-0.19%	11.3%
36	Illinois Tool Works	530.10	470.00	-2.38%	3.70	(0.0881)	0.7300	-6.43%	10.8%
37	Ingersoll-Rand	272.61	325.00	3.58%	1.35	0.0485	0.2616	1.27%	18.0%
38	Int'l Business Mach.	1385.20	1100.00	-4.51%	8.14	(0.3666)	0.8771	-32.15%	7.4%
39	ITT Corp.	181.57	177.00	-0.51%	2.47	(0.0126)	0.5952	-0.75%	13.1%
40	Johnson & Johnson	2840.20	2650.00	-1.38%	4.10	(0.0564)	0.7558	-4.26%	10.1%
41	Kimberly-Clark	420.90	400.00	-1.01%	4.74	(0.0480)	0.7889	-3.79%	12.9%
42	Kraft Foods	1533.80	1500.00	-0.44%	2.19	(0.0098)	0.5443	-0.53%	4.8%
43	Lilly (Eli)	1134.30	1100.00	-0.61%	2.91	(0.0178)	0.6568	-1.17%	8.6%
44	Lincoln Nat'l Corp.	264.23	225.00	-3.16%	1.82	(0.0576)	0.4505	-2.59%	8.4%
45	Lockheed Martin	409.00	350.00	-3.07%	4.06	(0.1247)	0.7539	-9.40%	13.2%
46	M&T Bank Corp.	1501.00	1425.00	-1.03%	2.38	(0.0246)	0.5791	-1.42%	11.0%
47	McDonald's Corp.	1165.30	1030.00	-2.44%	4.85	(0.1182)	0.7938	-9.38%	2.3%
48	Medtronic, Inc.	1124.90	980.00	-2.72%	4.48	(0.1218)	0.7766	-9.45%	9.2%
49	Microsoft Corp.	9380.00	7000.00	-5.69%	5.79	(0.3292)	0.8273	-27.23%	-1.2%
50	NIKE, Inc. 'B'	503.80	455.00	-2.02%	4.19	(0.0846)	0.7615	-6.44%	9.5%
51	Northrop Grumman	337.83	320.00	-1.08%	1.80	(0.0194)	0.4431	-0.86%	8.2%
52	PepsiCo, Inc.	1605.00	1450.00	-2.01%	7.05	(0.1418)	0.8582	-12.17%	10.3%
53	Pfizer, Inc.	6761.00	6600.00	-0.48%	2.23	(0.0107)	0.5511	-0.59%	6.9%
54	Procter & Gamble	3131.90	2950.00	-1.19%	3.10	(0.0368)	0.6770	-2.49%	6.5%
55	Raytheon Co.	426.20	400.00	-1.26%	2.15	(0.0271)	0.5343	-1.45%	8.6%
56	Raytheon Co.	62.03	67.00	1.55%	0.83	0.0129	(0.2056)	-0.26%	11.3%
57	Sigma-Aldrich	132.41	125.00	-1.15%	3.52	(0.0403)	0.7162	-2.89%	13.4%
58	Sysco Corp.	611.84	560.00	-1.76%	7.79	(0.1368)	0.8717	-11.92%	8.8%
59	Sysco Corp.	92.18	75.00	-4.04%	1.65	(0.0668)	0.3946	-2.63%	10.6%
60	United Parcel Serv.	1034.40	980.00	-1.07%	7.25	(0.0779)	0.8620	-6.72%	14.0%
61	United Technologies	981.52	925.00	-1.18%	2.76	(0.0326)	0.6383	-2.08%	11.8%
62	Verizon Communic.	2871.00	2850.00	-0.15%	3.20	(0.0047)	0.6875	-0.32%	8.6%
63	Wal-Mart Stores	3973.00	3500.00	-2.50%	3.36	(0.0841)	0.7024	-5.91%	10.0%
64	Walgreen Co.	991.14	975.00	-0.33%	3.23	(0.0106)	0.6907	-0.73%	11.8%
65	Wells Fargo	3297.10	3650.00	2.05%	2.34	0.0482	0.5733	2.76%	11.7%
66	Wyeth	1337.80	1340.00	0.03%	2.78	0.0009	0.6407	0.06%	14.2%

(a) www.valueline.com (retrieved Dec. 11, 2008).
(b) Average of High and Low expected market prices.
(c) Computed at (EPS - DPS) / EPS.
(d) Computed as EPS / BVPS.
(e) Product of BVPS and No. Shares Outstanding.
(f) Five-year rate of change.
(g) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(h) Product of year-end "r" for 2011-13 and Adjustment Factor.
(i) Average of High and Low expected market prices divided by 2011-13 BVPS.
(j) Product of change in common shares outstanding and M/B Ratio.
(k) Computed as 1 - B/M Ratio.
(l) Product of "s" and "v".
(m) Product of average "b" and adjusted "r", plus "sv".

FORWARD-LOOKING CAPM

UTILITY PROXY GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
		S&P 500						
	Company	Div Yield	Proj. Growth	Cost of Equity	Risk-Free Rate	Risk Premium	Beta	Implied Cost of Equity
1	ALLETE	3.6%	9.6%	13.2%	3.2%	10.0%	0.75	10.7%
2	Alliant Energy	3.6%	9.6%	13.2%	3.2%	10.0%	0.70	10.2%
3	Consolidated Edison	3.6%	9.6%	13.2%	3.2%	10.0%	0.65	9.7%
4	Dominion Resources	3.6%	9.6%	13.2%	3.2%	10.0%	0.70	10.2%
5	Duke Energy	3.6%	9.6%	13.2%	3.2%	10.0%	0.60	9.2%
6	FPL Group, Inc.	3.6%	9.6%	13.2%	3.2%	10.0%	0.80	11.2%
7	Integrys Energy Group	3.6%	9.6%	13.2%	3.2%	10.0%	0.70	10.2%
8	MDU Resources Group	3.6%	9.6%	13.2%	3.2%	10.0%	0.95	12.7%
9	NSTAR	3.6%	9.6%	13.2%	3.2%	10.0%	0.70	10.2%
10	OGE Energy Corp.	3.6%	9.6%	13.2%	3.2%	10.0%	0.75	10.7%
11	PG&E Corp.	3.6%	9.6%	13.2%	3.2%	10.0%	0.85	11.7%
12	Portland General Elec.	3.6%	9.6%	13.2%	3.2%	10.0%	0.70	10.2%
13	Progress Energy	3.6%	9.6%	13.2%	3.2%	10.0%	0.60	9.2%
14	SCANA Corp.	3.6%	9.6%	13.2%	3.2%	10.0%	0.70	10.2%
15	Sempra Energy	3.6%	9.6%	13.2%	3.2%	10.0%	0.90	12.2%
16	Southern Company	3.6%	9.6%	13.2%	3.2%	10.0%	0.55	8.7%
17	Vectren Corp.	3.6%	9.6%	13.2%	3.2%	10.0%	0.85	11.7%
18	Wisconsin Energy	3.6%	9.6%	13.2%	3.2%	10.0%	0.65	9.7%
19	Xcel Energy, Inc.	3.6%	9.6%	13.2%	3.2%	10.0%	0.75	10.7%
	Average							**10.5%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Dec. 18, 2008).
(b) Weighted average of Value Line, IBES, First Call, and Zacks earnings growth rates for the dividend paying firms in the S&P 500 based on data from www.valueline.com (retrieved Dec. 18, 2008), www.finance.yahoo.com (retrieved Dec. 19, 2008), *First Call Valuation Report* (retrieved Dec. 19, 2008), and www.zacks.com (retrieved Dec. 19, 2008).
(c) (a) + (b).
(d) Average yield on 20-year Treasury bonds for December 2008 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data.htm.
(e) (c) - (d).
(f) The Value Line Investment Survey (Nov. 7, Nov. 28, & Dec 26, 2008).
(g) (d) + (e) x (f).

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 140
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS William E. Avera (WEA-11)
DATE 09/16/09

FORWARD-LOOKING CAPM

NON-UTILITY PROXY GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
		S&P 500						
	Company	Div Yield	Proj. Growth	Cost of Equity	Risk-Free Rate	Risk Premium	Beta	Implied Cost of Equity
1	3M Company	3.6%	9.6%	13.2%	3.2%	10.0%	0.80	11.2%
2	Abbott Labs.	3.6%	9.6%	13.2%	3.2%	10.0%	0.60	9.2%
3	Aflac Inc.	3.6%	9.6%	13.2%	3.2%	10.0%	0.95	12.7%
4	Allergan, Inc.	3.6%	9.6%	13.2%	3.2%	10.0%	1.00	13.2%
5	Allstate Corp.	3.6%	9.6%	13.2%	3.2%	10.0%	1.05	13.7%
6	AT&T Inc.	3.6%	9.6%	13.2%	3.2%	10.0%	0.80	11.2%
7	Bard (C.R.)	3.6%	9.6%	13.2%	3.2%	10.0%	0.60	9.2%
8	Baxter Int'l Inc.	3.6%	9.6%	13.2%	3.2%	10.0%	0.70	10.2%
9	Becton, Dickinson	3.6%	9.6%	13.2%	3.2%	10.0%	0.70	10.2%
10	Bemis Co.	3.6%	9.6%	13.2%	3.2%	10.0%	0.90	12.2%
11	Boeing	3.6%	9.6%	13.2%	3.2%	10.0%	0.90	12.2%
12	Brown-Forman 'B'	3.6%	9.6%	13.2%	3.2%	10.0%	0.70	10.2%
13	Chevron Corp.	3.6%	9.6%	13.2%	3.2%	10.0%	0.90	12.2%
14	Chubb Corp.	3.6%	9.6%	13.2%	3.2%	10.0%	0.95	12.7%
15	Coca-Cola	3.6%	9.6%	13.2%	3.2%	10.0%	0.55	8.7%
16	Colgate-Palmolive	3.6%	9.6%	13.2%	3.2%	10.0%	0.60	9.2%
17	Commerce Bancshs.	3.6%	9.6%	13.2%	3.2%	10.0%	0.80	11.2%
18	ConocoPhillips	3.6%	9.6%	13.2%	3.2%	10.0%	1.10	14.2%
19	Du Pont	3.6%	9.6%	13.2%	3.2%	10.0%	1.00	13.2%
20	Eaton Corp.	3.6%	9.6%	13.2%	3.2%	10.0%	1.10	14.2%
21	Ecolab Inc.	3.6%	9.6%	13.2%	3.2%	10.0%	0.90	12.2%
22	Emerson Electric	3.6%	9.6%	13.2%	3.2%	10.0%	1.00	13.2%
23	Everest Re Group Ltd.	3.6%	9.6%	13.2%	3.2%	10.0%	0.85	11.7%
24	Exxon Mobil Corp.	3.6%	9.6%	13.2%	3.2%	10.0%	0.80	11.2%
25	Fortune Brands	3.6%	9.6%	13.2%	3.2%	10.0%	1.00	13.2%
26	Gallagher (Arthur J.)	3.6%	9.6%	13.2%	3.2%	10.0%	0.70	10.2%
27	Gen'l Dynamics	3.6%	9.6%	13.2%	3.2%	10.0%	0.85	11.7%
28	Gen'l Mills	3.6%	9.6%	13.2%	3.2%	10.0%	0.55	8.7%
29	Genuine Parts	3.6%	9.6%	13.2%	3.2%	10.0%	0.85	11.7%
30	Grainger (W.W.)	3.6%	9.6%	13.2%	3.2%	10.0%	1.00	13.2%
31	Heinz (H.J.)	3.6%	9.6%	13.2%	3.2%	10.0%	0.65	9.7%
32	Hewlett-Packard	3.6%	9.6%	13.2%	3.2%	10.0%	1.00	13.2%
33	Home Depot	3.6%	9.6%	13.2%	3.2%	10.0%	0.95	12.7%
34	Honeywell Int'l	3.6%	9.6%	13.2%	3.2%	10.0%	1.10	14.2%
35	Hormel Foods	3.6%	9.6%	13.2%	3.2%	10.0%	0.70	10.2%
36	Illinois Tool Works	3.6%	9.6%	13.2%	3.2%	10.0%	1.05	13.7%
37	Ingersoll-Rand	3.6%	9.6%	13.2%	3.2%	10.0%	1.20	15.2%
38	Int'l Business Mach.	3.6%	9.6%	13.2%	3.2%	10.0%	0.90	12.2%
39	ITT Corp.	3.6%	9.6%	13.2%	3.2%	10.0%	0.95	12.7%
40	Johnson & Johnson	3.6%	9.6%	13.2%	3.2%	10.0%	0.55	8.7%
41	Kimberly-Clark	3.6%	9.6%	13.2%	3.2%	10.0%	0.60	9.2%
42	Kraft Foods	3.6%	9.6%	13.2%	3.2%	10.0%	0.65	9.7%
43	Lilly (Eli)	3.6%	9.6%	13.2%	3.2%	10.0%	0.80	11.2%
44	Lincoln Nat'l Corp.	3.6%	9.6%	13.2%	3.2%	10.0%	1.40	[illegible]
45	Lockheed Martin	3.6%	9.6%	13.2%	3.2%	10.0%	0.80	11.2%
46	Manulife Fin'l	3.6%	9.6%	13.2%	3.2%	10.0%	1.25	15.7%
47	McDonald's Corp.	3.6%	9.6%	13.2%	3.2%	10.0%	0.75	10.7%
48	Medtronic, Inc.	3.6%	9.6%	13.2%	3.2%	10.0%	0.65	9.7%
49	Microsoft Corp.	3.6%	9.6%	13.2%	3.2%	10.0%	0.80	11.2%
50	NIKE, Inc. 'B'	3.6%	9.6%	13.2%	3.2%	10.0%	0.85	11.7%
51	Northrop Grumman	3.6%	9.6%	13.2%	3.2%	10.0%	0.75	10.7%
52	PepsiCo, Inc.	3.6%	9.6%	13.2%	3.2%	10.0%	0.60	9.2%
53	Pfizer, Inc.	3.6%	9.6%	13.2%	3.2%	10.0%	0.70	10.2%
54	Procter & Gamble	3.6%	9.6%	13.2%	3.2%	10.0%	0.55	8.7%
55	Raytheon Co.	3.6%	9.6%	13.2%	3.2%	10.0%	0.75	10.7%
56	Reinsurance Group	3.6%	9.6%	13.2%	3.2%	10.0%	0.85	11.7%
57	Sigma-Aldrich	3.6%	9.6%	13.2%	3.2%	10.0%	1.00	13.2%
58	Sysco Corp.	3.6%	9.6%	13.2%	3.2%	10.0%	0.65	9.7%
59	Torchmark Corp.	3.6%	9.6%	13.2%	3.2%	10.0%	1.00	13.2%
60	United Parcel Serv.	3.6%	9.6%	13.2%	3.2%	10.0%	0.80	11.2%
61	United Technologies	3.6%	9.6%	13.2%	3.2%	10.0%	1.00	13.2%
62	Verizon Communic.	3.6%	9.6%	13.2%	3.2%	10.0%	0.75	10.7%
63	Wal-Mart Stores	3.6%	9.6%	13.2%	3.2%	10.0%	0.65	9.7%
64	Walgreen Co.	3.6%	9.6%	13.2%	3.2%	10.0%	0.70	10.2%
65	Wells Fargo	3.6%	9.6%	13.2%	3.2%	10.0%	1.05	13.7%
66	Wyeth	3.6%	9.6%	13.2%	3.2%	10.0%	0.70	10.2%
	Average							**11.5%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Dec. 18, 2008).
(b) Weighted average of Value Line, IBES, First Call, and Zacks earnings growth rates for the dividend paying firms in the S&P 500 based on data from www.valueline.com (retrieved Dec. 18, 2008), www.finance.yahoo.com (retrieved Dec. 19, 2008), First CallValuation Report (retrieved Dec. 19, 2008), and www.zacks.com (retrieved Dec. 19, 2008).
(c) (a) + (b).
(d) Average yield on 20-year Treasury bonds for December 2008 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data.htm.
(e) (c) - (d).
(f) www.valueline.com (retrieved Dec. 11, 2008).
(g) (d) + (e) x (f).
(h) Excludes highlighted figures.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 141
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS William E. Avera (WEA-12)
DATE 09/16/09

EXPECTED EARNINGS APPROACH

UTILITY PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	ALLETE	8.5%	1.0416	8.9%
2	Alliant Energy	10.5%	1.0301	10.8%
3	Consolidated Edison	8.5%	1.0189	8.7%
4	Dominion Resources	15.0%	1.0578	15.9%
5	Duke Energy	8.0%	1.0126	8.1%
6	FPL Group, Inc.	13.5%	1.0379	14.0%
7	Integrys Energy Group	10.0%	1.0173	10.2%
8	MDU Resources Group	12.0%	1.0488	12.6%
9	NSTAR	14.5%	1.0275	14.9%
10	OGE Energy Corp.	11.5%	1.0446	12.0%
11	PG&E Corp.	11.5%	1.0332	11.9%
12	Portland General Elec.	9.0%	1.0406	9.4%
13	Progress Energy	9.5%	1.0192	9.7%
14	SCANA Corp.	10.5%	1.0401	10.9%
15	Sempra Energy	13.5%	1.0256	13.8%
16	Southern Company	14.0%	1.0347	14.5%
17	Vectren Corp.	11.5%	1.0259	11.8%
18	Wisconsin Energy	12.5%	1.0286	12.9%
19	Xcel Energy, Inc.	10.5%	1.0268	10.8%
	Average			**11.7%**

(a) 3-5 year projections from The Value Line Investment Survey (Nov. 7, Nov. 28 & Dec. 26, 2008).
(b) Adjustment to convert year-end "r" to an average rate of return from Exhibit WEA-8.
(c) (a) x (b).

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 142
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS William E. Avera (WEA-13)
DATE 09/16/09

EXHIBIT WEA-14

FPL ADJUSTED CAPITAL STRUCTURE

(December 31, 2010, $000)

Component	Amount	Percent
Short-term Debt	$ 161,857	1.1%
Long-term Debt	6,327,047	44.1%
Common Equity	8,178,980	55.8%
Total	$14,667,884	100.00%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 143
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS William E. Avera (WEA-14)
DATE 09/16/09

CAPITAL STRUCTURE

ELECTRIC UTILITY OPERATING COS.

	Company	Long-term Debt	Preferred Stock	Common Equity
1	Alabama Power Company	50.9%	6.6%	42.5%
2	Carolina Power & Light Co.	47.6%	0.8%	51.6%
3	Consolidated Edison of NY	47.3%	1.4%	51.3%
4	Duke Energy Carolinas	44.8%	0.0%	55.2%
5	Duke Energy Indiana	47.8%	0.0%	52.2%
6	Duke Energy Kentucky	41.4%	0.0%	58.6%
7	Duke Energy Ohio	22.9%	0.0%	77.1%
8	Florida Power Corp.	51.5%	0.5%	48.0%
9	Georgia Power	47.8%	2.1%	50.1%
10	Gulf Power	47.2%	6.2%	46.6%
11	Interstate Power & Light	40.7%	9.8%	49.5%
12	Mississippi Power	30.5%	3.5%	66.0%
13	Northern States Power Co. (MN)	46.7%	0.0%	53.3%
14	Northern States Power Co. (WI)	40.4%	0.0%	59.6%
15	NSTAR Electric Co.	52.1%	1.1%	46.8%
16	Oklahoma Gas & Electric	37.2%	0.0%	62.8%
17	Orange & Rockland	48.6%	0.0%	51.4%
18	Pacific Gas & Electric Co.	46.4%	1.5%	52.1%
19	Portland General Electric Co.	49.9%	0.0%	50.1%
20	Public Service Co. of Colorado	39.3%	0.0%	60.7%
21	San Diego Gas & Electric	44.6%	2.1%	53.2%
22	South Carolina Electric & Gas	41.7%	2.3%	56.0%
23	Southern Power Co.	54.6%	0.0%	45.4%
24	Southwestern Public Service Co.	49.6%	0.0%	50.4%
25	Vectren Utility Holdings	49.4%	0.0%	50.6%
26	Virginia Electric Power	45.5%	5.9%	48.6%
27	Wisconsin Electric Power Co.	38.6%	0.7%	60.7%
28	Wisconsin Power & Light	35.2%	3.5%	61.2%
29	Wisconsin Pub Serv. Corp.	38.7%	2.6%	58.7%
	Average	**44.1%**	**1.7%**	**54.2%**

Source: At fiscal year-end 2007 from Company Form 10-K Reports and FERC Form-1 Reports.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 144
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS William E. Avera (WEA-15)
DATE 09/16/09

CAPITAL STRUCTURE

UTILITY PROXY GROUP

		At Fiscal Year-End 2007 (a)			Value Line Projected (b)		
	Company	**Long-term Debt**	**Preferred**	**Common Equity**	**Long-term Debt**	**Other**	**Common Equity**
1	ALLETE	59.7%	0.2%	40.1%	47.5%	0.0%	52.5%
2	Alliant Energy	34.5%	5.4%	60.0%	32.0%	4.0%	64.0%
3	Consolidated Edison	47.4%	1.2%	51.4%	50.0%	0.5%	49.5%
4	Dominion Resources	59.2%	2.2%	38.7%	48.5%	1.0%	50.5%
5	Duke Energy	34.0%	0.0%	66.0%	44.5%	0.0%	55.5%
6	FPL Group, Inc.	54.2%	0.0%	45.8%	54.5%	0.0%	45.5%
7	Integrys Energy Group	41.4%	0.9%	57.7%	38.0%	0.5%	61.5%
8	MDU Resources Group	34.1%	0.4%	65.5%	30.0%	0.5%	69.5%
9	NSTAR	53.7%	1.1%	45.2%	49.0%	1.0%	50.0%
10	OGE Energy Corp.	44.5%	0.0%	55.5%	53.5%	0.0%	46.5%
11	PG&E Corp.	48.1%	1.5%	50.4%	50.5%	0.5%	49.0%
12	Portland General Elec.	49.9%	0.0%	50.1%	48.0%	0.0%	52.0%
13	Progress Energy	52.8%	0.5%	46.7%	51.5%	0.5%	48.0%
14	SCANA Corp.	50.3%	1.8%	47.9%	53.5%	1.0%	45.5%
15	Sempra Energy	34.5%	1.4%	64.2%	40.0%	1.0%	59.0%
16	Southern Company	53.2%	3.8%	43.0%	52.0%	3.0%	45.0%
17	Vectren Corp.	50.2%	0.0%	49.8%	50.5%	0.0%	49.5%
18	Wisconsin Energy	53.0%	0.5%	46.6%	49.0%	0.5%	50.5%
19	Xcel Energy, Inc.	52.1%	0.8%	47.1%	51.0%	0.5%	48.5%
	Average	**47.7%**	**1.1%**	**51.1%**	**47.0%**	**0.8%**	**52.2%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Nov. 7, Nov. 28, & Dec. 26, 2008).

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 145
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS William E. Avera (WEA-16)
DATE 09/16/09

EXHIBIT WEA-17

ENDNOTES TO DIRECT TESTIMONY OF WILLIAM E. AVERA

[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).

[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

[3] Kearns, Jeff, "VIX 'Exploding' as Stocks Plunge on Growing Recession Concern," *Bloomberg* (Oct. 15, 2008).

[4] Riddell, Kelly, "Cash-Starved Companies Scrap Dividends, Tap Credit," Pittsburgh Post-Gazette (Oct. 2, 2008).

[5] *Letter to House of Representatives*, Thomas R. Kuhn, President, Edison Electric Institute (Sep. 24, 2008).

[6] Smith, Rebecca, "Corporate News: Utilities' Plans Hit by Credit Markets," *Wall Street Journal* at B4 (Oct. 1, 2008).

[7] *Rudden's Energy Strategy Report* (Oct. 1, 2008).

[8] Standard & Poor's Corporation, "Industry Report Card: U.S. Electric Utility Credit Quality Remains Strong Amid Continuing Economic Downturn," *RatingsDirect* (Dec. 19, 2008).

[9] Fitch Ratings Ltd., "EEI 2008 Wrap-Up: Cost of Capital Rising," *Global Power North America Special Report* (Nov. 17, 2008).

[10] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22. 2008).

[11] *Id.*

[12] Kruger, Daniel and Cordell Eddings, "Treasury Bills Trade at Negative Rates as Haven Demand Surges," www.bloomberg.com (Dec. 9, 2008).

[13] Standard & Poor's Corporation, "Credit Trends: U.S. Composite Credit Spreads Daily (Dec. 2, 2008)," *RatingsDirect* (Dec. 2, 2008).

[14] Gongloff, Mark, "Ahead of the Tape: The Shocks Are Getting A Workout," *The Wall Street Journal* at C1 (Sep. 17, 2008).

[15] Grabelsky, Glen, "Surviving the Present, Preparing for the Future," *Fitch Ratings' 20th Annual Global Power Breakfast* (Nov. 10, 2008).

[16] Fitch Ratings, Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22, 2008).

[17] Moody's Investors Service, "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

[18] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).

[19] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* at 6 (Aug. 2007).

[20] Fitch Ratings, Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North American Special Report* (Dec. 22, 2008).

[21] Standard & Poor's Corporation, "Florida Power & Light Co.," *RatingsDirect* (Aug. 20, 2008).

[22] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities: Six-Month Industry Update," *Industry Outlook* (July 2008).

[23] Standard & Poor's Corporation, "Ratings Roundup: Utility Sector Experienced Equal Number Of Upgrades And Downgrades During Second Quarter Of 2008," *RatingsDirect* (Jul. 22, 2008).

[24] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22, 2008).

[25] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).

[26] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities: Six-Month Industry Update," *Industry Outlook* (July 2008).

[27] Fitch Ratings, Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22, 2008).

[28] Standard & Poor's Corporation, "Measuring Nuclear Risk in a Competitive Environment," *CreditWeek* (Aug. 8, 1994).

[29] Moody's Investors Service, "New Nuclear Generation in the United States: Keeping Options Open vs. Addressing An Inevitable Necessity," *Special Comment* (Oct. 2007).

[30] *Id.*

[31] *Id.*

[32] Fitch Ratings Ltd., "Florida Power & Light Company," *Global Power North American Credit Analysis* (Feb. 12, 2008).

[33] Standard & Poor's Corporation, "Industry Report Card: U.S. Electric Utility Credit Quality Remains Strong Amid Continuing Economic Downturn," *RatingsDirect* (Dec. 19, 2008).

[34] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* at Part 2, p. 4 (1997).

[35] Thomson Financial, an arm of Thomson Reuters, separately compiles and publishes consensus securities analyst growth rates under the IBES and First Call brands.

[36] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* at 58 (1994).

[37] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never strictly met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity.

[38] The Value Line Investment Survey (Sep. 15, 1995 at 161, Dec. 28, 2007 at 695).

[39] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview" at 1 (Dec. 4, 1996).

[40] The Value Line Investment Survey, *Subscriber's Guide* at 53.

[41] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).

[42] *Id.* at 88.

[43] Liu, Jing, Nissim, Doron, & Thomas, Jacob, "Is Cash Flow King in Valuations?," *Financial Analysts Journal*, Vol. 63, No. 2 at 56 (March/April 2007).

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

[45] *Southern California Edison Company*, 92 FERC ¶ 61,070 (2000) at p. 22.

[46] *Kern River Gas Transmission Company*, Opinion No. 486, 117 FERC ¶ 61,077 at P 140 & n. 227 (2006).

[47] *Id.*

[48] Moody's Investors Service, www.credittrends.com.

[49] As highlighted on Exhibit WEA-7, these DCF estimates were 6.9 percent and 5.7 percent, respectively

[50] *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205 (2004).

[51] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports* at 65 (1994).

[52] The forward-looking CAPM is more comparable to the arithmetic mean than the geometric mean. This distinction was made clear in the new edition of the text used by the Chartered Financial Analyst (CFA) program worldwide: "the geometric mean is appropriate for making investment statements about past performance…the arithmetic mean is appropriate for making investment statements in a forward-looking context." DeFusco, Richard A., CFA, McLeavey, Dennis W., CFA, Pinto, Jerald E., CFA, Runkle, David E., CFA, *Quantitative Investment Analysis (Second Edition)*, at 127 (2007).

[53] The Value Line Investment Survey at 687 (Dec. 26, 2008).

[54] The Value Line Investment Survey 446 (Dec. 12, 2008).

[55] Roger A. Morin, "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports* (1994) at 166.

[56] Application of Yankee Gas Services Company for a Rate Increase, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6%.

[57] Staff witness Mr. Maurey utilized a 26 basis point adjustment in Docket No. 000824-EI, with the FPSC incorporating a 4 percent flotation cost adjustment in its June 10, 2004 Order No. PSC-04-0587-PAA-WS.

[58] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22, 2008).

[59] *Id.*

[60] Fitch Ratings Ltd., "Florida Power & Light Company," *Global Power North America Credit Analysis* (Feb. 12, 2008).

[61] Moody's Investors Service, "Regulatory Pressures Increase For U.S. Electric Utilities," *Special Comment* (March 2007).

[62] Standard & Poor's Corporation, "Assessing U.S. Utility Regulatory Environments," *RatingsDirect* (Nov. 7, 2008).

[63] Standard & Poor's Corporation, "Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements," *RatingsDirect* (May 7, 2007).

[64] *Id.*

[65] *Id.*

[66] Standard & Poor's Corporation, "Implications Of Operating Leases On Analysis Of U.S. Electric Utilities," *RatingsDirect* (Jan. 15, 2008).

[67] Standard & Poor's Corporation, "Florida Power & Light Co.," *RatingsDirect* (Aug. 20, 2008).

[68] Apart from the immediate impact that the fixed obligation of purchased power costs has on the utility's financial risk, higher fixed charges also reduce ongoing financial flexibility, and the utility may face other uncertainties, such as potential replacement power costs in the event of supply disruption.

[69] *Stipulation and Settlement*, Docket No. 050045-EI at P 15 (Aug. 22, 2005).

[70] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007); "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

[71] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities," *Industry Outlook* (Jan. 2009).

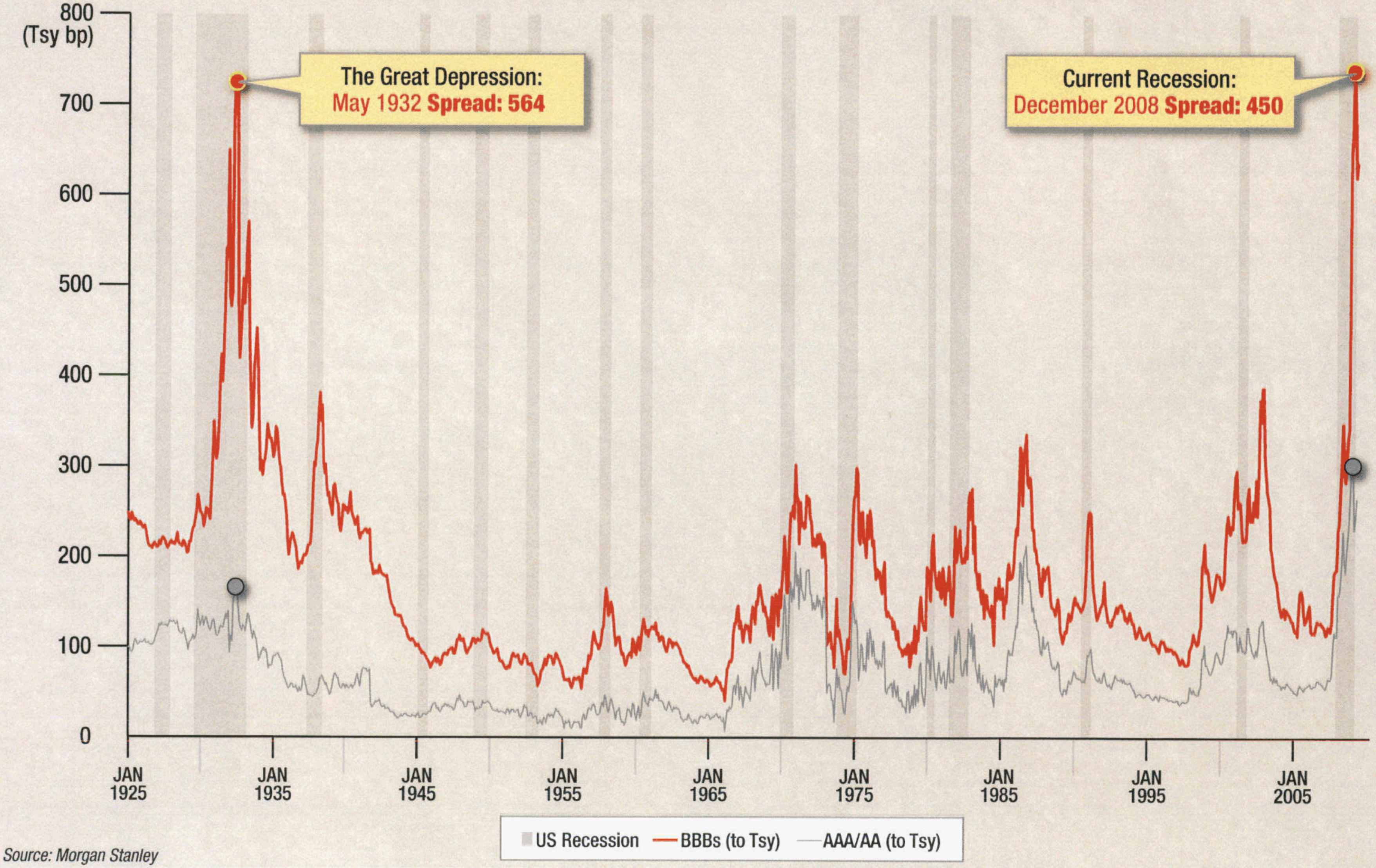
[72] *Id.*

[73] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities: Six-Month Industry Update," *Industry Outlook* (July 2008).

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 147
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Armando Pimentel (AP-1)
DATE 10/21/09

Credit Spreads Not This Wide Since Great Depression

Comparison of AAA/AA to BBBs Rated Credit



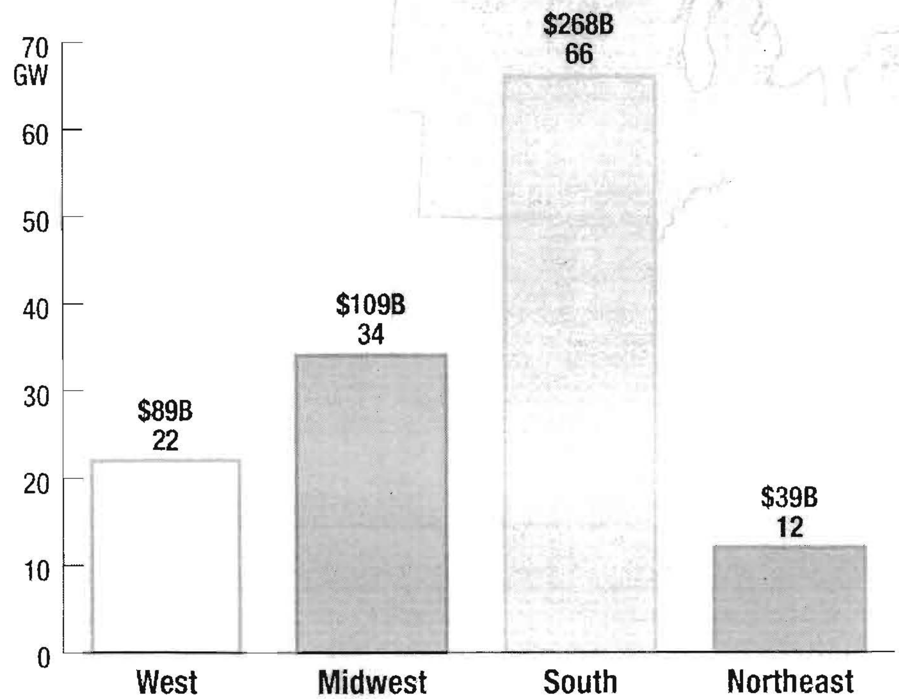
Source: Morgan Stanley

Docket No. 080677-EI
Historical Credit Spreads
Exhibit AP-1, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 148
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Armando Pimentel (AP-2)
DATE 10/21/09

Southern U.S. Projecting Largest Increase in Needs

Generation Capacity Increase By Region Through 2030



Source: The Brattle Group "Transforming America's Power Industry: The Investment Challenge 2010–2030," November 2008

Projected Industry Capital Expenditures Through 2030

Generation	$ 505 Billion
Transmission	$ 298 Billion
AMI and EE/DR	$ 85 Billion
Distribution	$ 582 Billion
Total	**$1.470 Trillion**

Docket No. 080677-EI
Capital Investment &
Generation Capacity
Additions
Exhibit AP-2, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

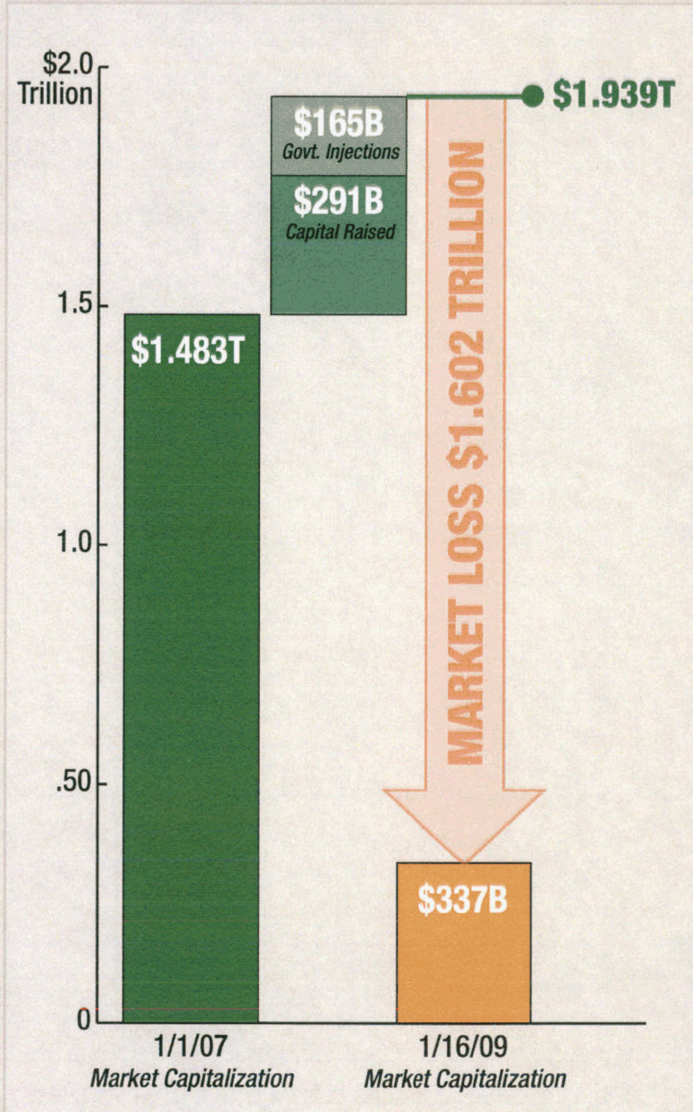
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 149

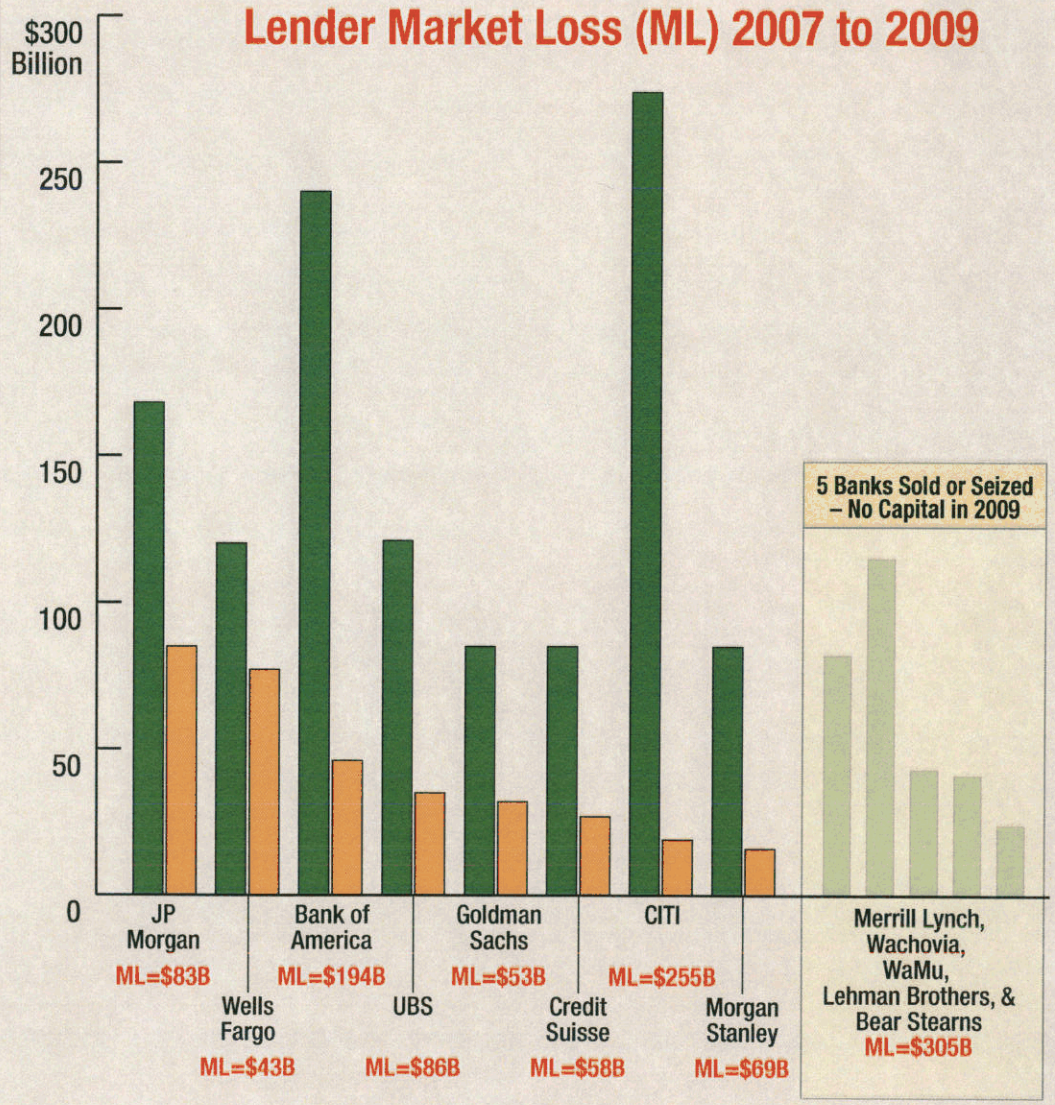
COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS Armando Pimentel (AP-3)

DATE 10/21/09

Market Capitalization $1.6T Decrease From 2007 to 2009





Source: JP Morgan

Docket No. 080677-EI
Market Capitalization
Exhibit AP-3, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080677-EI & 090130-EI EXHIBIT 150

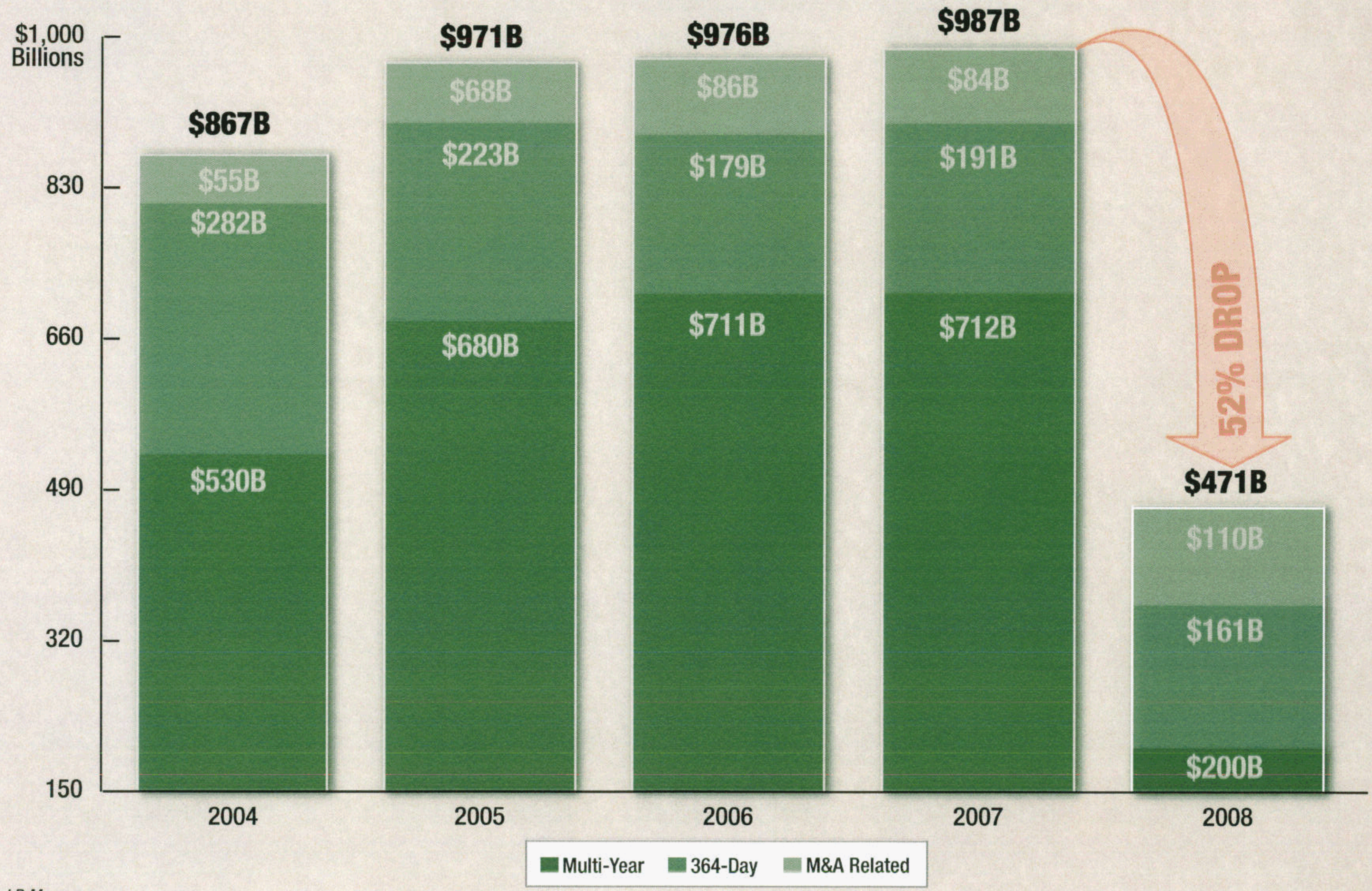
COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS Armando Pimentel (AP-4)

DATE 10/21/09

As Banks Reduce Leverage, Utilities Need New Sources of Liquidity

U.S. High Grade Credit Facilities



Source: J.P. Morgan

Docket No. 080677-EI
U.S. High Grade Credit Facilities
Exhibit AP-4, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION

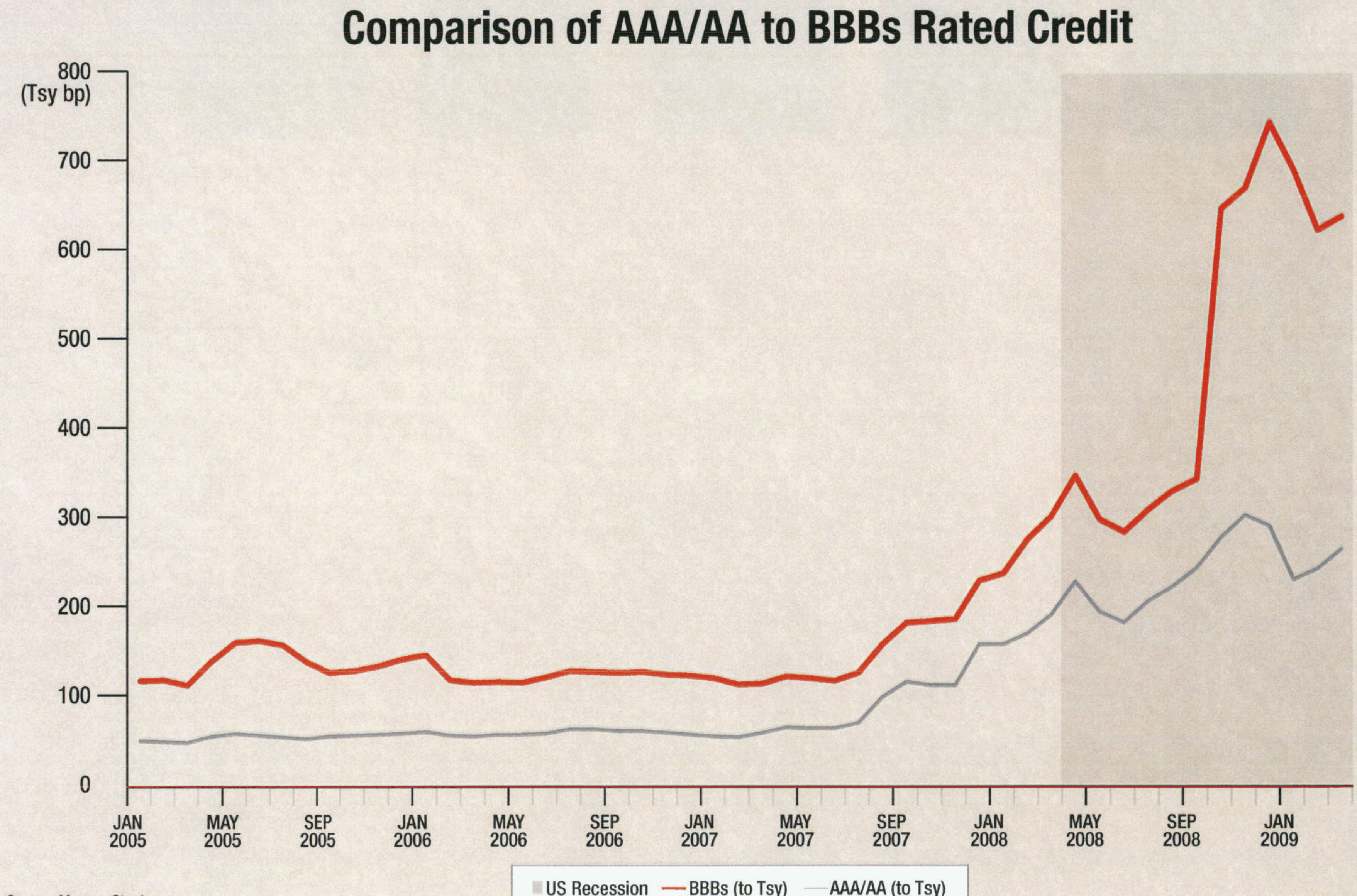
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 151

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS Armando Pimentel (AP-5)

DATE 10/21/09

Credit Spreads Have Increased Dramatically Since 2005

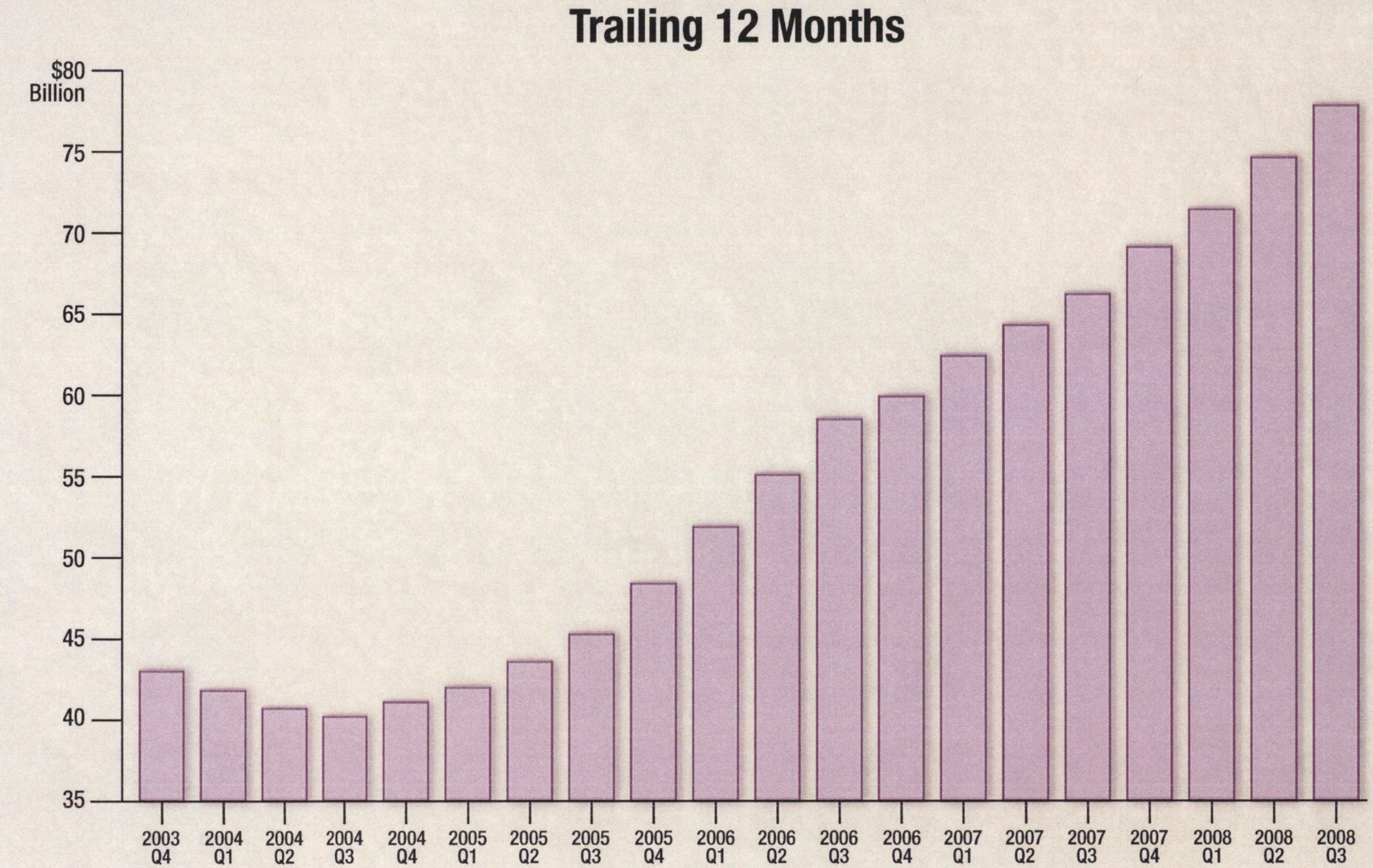


Source: Morgan Stanley

Docket No. 080677-EI
Credit Spreads since 2005
Exhibit AP-5, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 152
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Armando Pimentel (AP-6)
DATE 10/21/09

Utility Industry Capital Expenditures



Source: Edison Electric Institute

Docket No. 080677-EI
Historical Capital
Expenditures
Exhibit AP-6, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 153
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Armando Pimentel (AP-7)
DATE 10/21/09

FPL Test Year Capital Structure

13-Month Average

	Regulatory Capital Structure		Adjusted Capital Structure		
	Jurisdictional Adjusted	Ratio	Adjustments	Adjusted	Ratio
Long-Term Debt	$ 5,377,787[1]	31.5%	$ 949,260[2]	$ 6,327,047	43.1%
Preferred Stock	–	0.00%			
Customer Deposits	564,652	3.3%			
Common Equity	8,178,980	47.9%		8,178,980	55.8%
Short-Term Debt	161,857	1.0%		161,857	1.1%
Deferred Income Taxes	2,723,327	16.0%			
Investment Tax Credits	56,983	0.3%			
TOTAL:	**$17,063,587**	100%	**$ 949,260**	**$14,667,884**	**100%**

[1] Jurisdictional adjusted long-term debt excludes $546 million Storm Recovery Bonds.
[2] Adjustment to reflect imputed debt for purchased power obligations.

Docket No. 080677-EI
FPL Capital Structure
Exhibit AP-7, Page 1 of 1

MFRS AND SCHEDULES SPONSORED AND CO-SPONSORED BY JOSEPH A. ENDER

MFR #	PERIOD	TITLE
SOLE SPONSORSHIP:		
E-2	Test Subsequent	Explanation of Variations from Cost of Service Study Approved in Company's Last Rate Case
E-3a	Test Subsequent	Cost of Service Study - Allocation of Rate Base Components to Rate Schedule
E-3b	Test Subsequent	Cost of Service Study - Allocation of Expense Components to Rate Schedule
E-4a	Test Subsequent	Cost of Service Study - Functionalization and Classification of Rate Base
E-4b	Test Subsequent	Cost of Service Study - Functionalization and Classification of Expenses
E-6a	Test Subsequent	Cost of Service Study - Unit Costs, Present Rates
E-6b	Test Subsequent	Cost of Service Study - Unit Costs, Proposed Rates
E-10	Test Subsequent	Cost of Service Study - Development of Allocation Factors
E-17	Historic	Load Research Data

JOINT OR CO-SPONSORSHIP:		
B-2	Historic Prior Test Subsequent	Rate Base Adjustments
B-6	Historic Test Subsequent	Jurisdictional Separation Factors - Rate Base
C-4	Historic Test Subsequent	Jurisdictional Separation Factors - Net Operating Income
E-1	Test Subsequent	Cost of Service Studies
E-9	Test Subsequent	Cost of Service - Load Data
E-11	Test Subsequent	Development of Coincident and Non-Coincident Demands for Cost Study
E-16	Prior Test Subsequent	Customers by Voltage Level
E-19a	Test Subsequent	Demand and Energy Losses
E-19b	Test Subsequent	Energy Losses
E-19c	Test Subsequent	Demand Losses
F-5	Test Subsequent	Forecasting Models

WCEC UNIT 3 SCHEDULES SPONSORED OR CO-SPONSORED:		
B-6	WCEC 3 Adj '11	Jurisdictional Separation Factors - Rate Base
C-4	WCEC 3 Adj '11	Jurisdictional Separation Factors - Net Operating Income

2009 SUPPLEMENTAL MFRS SPONSORED OR CO-SPONSORED:		
B-6	2009 Supplemental	Jurisdictional Separation Factors - Rate Base
C-4	2009 Supplemental	Jurisdictional Separation Factors - Net Operating Income
E-17	2009 Supplemental	Load Research Data
F-5	2009 Supplemental	Forecasting Models

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 154
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Joseph A. Ender (JAE-1)
DATE 09/05/09

SUMMARY OF RATE CLASSES CONSOLIDATED FOR LOAD RESEARCH PURPOSES

RATE CLASS	RATE CLASS DESCRIPTION	RATE SCHEDULE(S)	RATE SCHEDULE DESCRIPTION
RETAIL:			
CILC-1D	Commercial/Industrial Load Control - Distribution	CILC-1D	Commercial/Industrial Load Control Program - Distribution (Closed Schedule)
CILC-1T	Commercial/Industrial Load Control - Transmission	CILC-1T	Commercial/Industrial Load Control Program - Transmission (Closed Schedule)
CILC-1G	Commercial/Industrial Load Control - General	CILC-1G	Commercial/Industrial Load Control Program - General (Closed Schedule)
CS(T)-1	Curtailable Service 1	CS-1, CST-1	Curtailable Service & Time of Use (500-1999 kW)
CS(T)-2	Curtailable Service 2	CS-2, CST-2	Curtailable Service & Time of Use (2000 kW +)
CS(T)-3	Curtailable Service 3	CS-3, CST-3	Curtailable Service & Time of Use (2000 kW +) Transmission
GS(T)-1	General Service Non-Demand	GS-1, GST-1, WIES-1	General Service Non Demand & Time of Use (0-20 kW) and Wireless Internet Electric Service
GSCU-1	General Service Constant Usage	GSCU-1	General Service Constant Usage
GSD(T)-1	General Service Demand	GSD-1, GSDT-1	General Service Demand & Time of Use (21-499 kW)
GSLD(T)-1	General Service Large Demand 1	GSLD-1, GSLDT-1	General Service Large Demand & Time of Use (500-1999 kW)
GSLD(T)-2	General Service Large Demand 2	GSLD-2, GSLDT-2	General Service Large Demand & Time of Use (2000 kW +)
GSLD(T)-3	General Service Large Demand 3	GSLD-3, GSLDT-3	General Service Large Demand & Time of Use (2000 kW +) Transmission
HLFT-1	High Load Factor	HLFT-1	High Load Factor – Time of Use (21-499 kW)
HLFT-2	High Load Factor	HLFT-2	High Load Factor – Time of Use (500-1999 kW)
HLFT-3	High Load Factor	HLFT-3	High Load Factor – Time of Use (2000 kW +)
METRO	Metropolitan Transit Service	MET	Metropolitan Transit Service
OL-1	Outdoor Lighting	OL-1	Outdoor Lighting
OS-2	Sports Field Service	OS-2, RL-1	Sports Field Service & Recreational Lighting
RS(T)-1	Residential Service	RS-1, RST-1	Residential Service & Time of Use
SDTR-1	Seasonal Demand 1	SDTR-1A, SDTR-1B	Seasonal Demand – Time of Use Rider (21-499 kW)
SDTR-2	Seasonal Demand 2	SDTR-2A, SDTR-2B	Seasonal Demand – Time of Use Rider (500-1999 kW)
SDTR-3	Seasonal Demand 3	SDTR-3A, SDTR-3B	Seasonal Demand – Time of Use Rider (2000 kW +)
SL-1	Street Lighting	SL-1, PL-1	Street Lighting & Premium Lighting
SL-2	Traffic Signal Service	SL-2	Traffic Signal Service
SST-1D	Standby and Supplemental Service - Distribution	SST-1D, SST-2D, SST-3D	Standby and Supplemental Service - Distribution
SST-1T	Standby and Supplemental Service - Transmission	SST-1T	Standby and Supplemental Service - Transmission
WHOLESALE:			
FKEC/KW	Florida Keys Electric Cooperative/Key West		
MDWS	Miami-Dade Waste Service		
SEMINOLE	Seminole Electric Cooperative		
LCEC	Lee County Electric Cooperative		

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 155
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Joseph A. Ender (JAE-2)
DATE 09/05/09

RATE CLASS EXTRAPOLATION METHODOLOGY

RATE CLASS	RATE CLASS DESCRIPTION	EXTRAPOLATION METHODOLOGY
100% METERED[1]		
CILC-1D	Commercial/Industrial Load Control - Distribution	Ratio
CILC-1G	Commercial/Industrial Load Control - General	Ratio
CILC-1T	Commercial/Industrial Load Control - Transmission	Mean Per Unit
CS(T)-1	Curtailable Service 1	Ratio
CS(T)-2	Curtailable Service 2	Mean Per Unit
CS(T)-3	Curtailable Service 3	Mean Per Unit
GSLD(T)-2	General Service Large Demand 2	Ratio
GSLD(T)-3	General Service Large Demand 3	Mean Per Unit
HLFT-3	High Load Factor 3	Ratio
METRO	Metropolitan Transit Service	Mean Per Unit
SDTR-2	Seasonal Demand 2	Ratio
SDTR-3	Seasonal Demand 3	Mean Per Unit
SST-D	Standby and Supplemental Service - Distribution	Mean Per Unit
SST-1T	Standby and Supplemental Service - Transmission	Mean Per Unit
FKEC/KW[2]	Florida Keys Electric Cooperative/Key West	Mean Per Unit
MDWS[2]	Miami-Dade Waste Service	Mean Per Unit
Seminole[2]	Seminole Electric Cooperative	Mean Per Unit
LCEC[2]	Lee County Electric Cooperative	Mean Per Unit
MODELED		
OL-1	Outdoor Lighting	Mean Per Unit
SL-1	Street Lighting	Mean Per Unit
SL-2	Traffic Signal Service	Mean Per Unit
SAMPLED		
GS(T)-1	General Service Non-Demand	Ratio
GSCU-1	General Service Constant Usage	Ratio
GSD(T)-1	General Service Demand	Ratio
GSLD(T)-1	General Service Large Demand 1	Ratio
HLFT-1	High Load Factor 1	Ratio
HLFT-2	High Load Factor 2	Ratio
OS-2	Sports Field Service	Ratio
RS(T)-1	Residential Service	Ratio
SDTR-1	Seasonal Demand 1	Ratio

(1) The use of extrapolation techniques (Ratio or Mean Per Unit) for 100% metered rate classes is necessary to account for missing interval data resulting from meter, data translation or communication issues. These two methodologies will extrapolate to the population level and, thus, account for any missing interval data.

(2) Wholesale

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 156
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Joseph A. Ender (JAE-3)
DATE 09/05/09

COST OF SERVICE STUDY
COST OF SERVICE METHODOLOGY BY COMPONENT

COSS ID	Description	COSS Methodology	Allocator

BALANCE SHEET - ASSETS

PLANT IN SERVICE
INTANGIBLE -

BAL001000	PIS - INTANGIBLE	Total Labor	LABOR_TOT

PRODUCTION -

STEAM:

BAL001100	PIS - STEAM	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
BAL001800	PIS - STEAM - ACQ ADJ SCHERER PLANT 4	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)

NUCLEAR:

BAL001200	PIS - NUCL - TURKEY PT	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
BAL001220	PIS - NUCL - ST LUCIE 1	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
BAL001250	PIS - NUCL - ST LUCIE COMMON	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
BAL001270	PIS - NUCL - ST LUCIE 2	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)

OTHER PRODUCTION:

BAL001300	PIS - OTHER PRODUCTION	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)

TRANSMISSION -

BAL001400	PIS - TRANSMISSION	12CP & 1/13 adjusted for transmission pulloffs for retail customers	Compound Allocator - FPL301 - Transmission Customers Pull-offs (0.2%) FPL101 - Average 12CP Demand (12/13th of 99.8%) FPL201 - MWH Sales (1/13th of 99.8%)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 157
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Joseph A. Ender (JAE-4)
DATE 09/05/09

COST OF SERVICE STUDY
COST OF SERVICE METHODOLOGY BY COMPONENT

COSS ID	Description	COSS Methodology	Allocator
DISTRIBUTION -			
BAL001510	PIS - DIST - ACCT 360 - LAND & LAND RIGHTS	GCP demand, adjusted for losses, for loads at Primary and Secondary voltage levels only.	FPL104 - Distribution GCP Demand
BAL001511	PIS - DIST - ACCT 361 - STRUCT & IMPROV	GCP demand, adjusted for losses, for loads at Primary and Secondary voltage levels only.	FPL104 - Distribution GCP Demand
BAL001512	PIS - DIST - ACCT 362 - STATION EQUIP	GCP demand, adjusted for losses, for loads at Primary and Secondary voltage levels only.	FPL104 - Distribution GCP Demand
BAL001514	PIS - DIST - ACCT 364 - POLES, TOWERS & FIXTURES	Poles, towers and fixtures classified as demand and functionalized between primary and secondary, adjusted for distribution pulloffs for primary and secondary customers.	<u>Compound Allocator -</u> FPL302 - Primary Customers Pull-offs (0.3%) FPL104 - Distribution GCP Demand (91.8%) FPL105 - Secondary GCP Demand (7.9%)
BAL001515	PIS - DIST - ACCT 365 - OVERHEAD CONDUCT & DEVIC	Overhead conductors and devices classified as demand and functionalized between primary and secondary, adjusted for distribution pulloffs for primary and secondary customers.	<u>Compound Allocator -</u> FPL302 - Primary Customers Pull-offs (0.2%) FPL104 - Distribution GCP Demand (78.8%) FPL105 - Secondary GCP Demand (21.0%)
BAL001516	PIS - DIST - ACCT 366 - UNDERGROUND CONDUIT	Underground conduit classified as demand and functionalized between primary and secondary.	<u>Compound Allocator -</u> FPL104 - Distribution GCP Demand (93.9%) FPL105 - Secondary GCP Demand (6.1%)
BAL001517	PIS - DIST - ACCT 367 - UNDERGROUND CONDUCT & DEVIC	Underground conductors and devices classified as demand and functionalized between primary and secondary.	<u>Compound Allocator -</u> FPL104 - Distribution GCP Demand (88.1%) FPL105 - Secondary GCP Demand (11.9%)
BAL001518	PIS - DIST - ACCT 368 - LINE TRANSFORMERS	Line transformers, capacitors and network protectors classified as demand and functionalized between primary and secondary.	<u>Compound Allocator -</u> FPL104 - Distribution GCP Demand (10.9%) FPL109 - Secondary Customer NCP Demand (89.1%)
BAL001519	PIS - DIST - ACCT 369 - SERVICES	Average number of secondary voltage level customers for retail only, excluding lighting services.	FPL303 - Average Secondary Customers
BAL001520	PIS - DIST - ACCT 370 - METERS	Average number of meters for the rate class multiplied by the average meter unit cost, excluding lighting services.	FPL325 - Meter Costs
BAL001521	PIS - DIST - ACCT 371 - INSTALLS ON CUST PREMISES	100% assignment to Outdoor Lighting.	FPL509 - Outdoor Lighting
BAL001523	PIS - DIST - ACCT 373 - STREET LIGHTING & SIGNAL EQUIP	The number of lighting fixtures for the Street Lighting classes only.	FPL508 - Street Lights
GENERAL -			
BAL001600	PIS - GENERAL PLT - TRANSPORTATION EQUIP	Total Labor	LABOR_TOT
BAL001710	PIS - GENERAL PLT - STRUCTURES	Total Labor	LABOR_TOT

COST OF SERVICE STUDY
COST OF SERVICE METHODOLOGY BY COMPONENT

COSS ID	Description	COSS Methodology	Allocator
BAL001720	PIS - GENERAL PLT - OTHER	Total Labor	LABOR_TOT
ACCUMULATED PROVISION FOR DEPRECIATION			
INTANGIBLE -			
BAL008000	ACC DEP - INTANGIBLE	Total Labor	LABOR_TOT
BAL008075	ACC DEP - INTANG - ITC INTEREST SYNCH	Total Labor	LABOR_TOT
BAL008090	ACC DEP - INTANG - UNASSIGNED BOTTOM LINE	Total Plant In Service - Gross	PLT_GROSS
PRODUCTION -			
STEAM:			
BAL008100	ACC DEP - STEAM	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
BAL008155	ACC DEP - FOSSIL DECOMMISSIONING	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
BAL009180	ACC DEP - STEAM - AMORT ELECTRIC PLT ACQ ADJ	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
NUCLEAR:			
BAL008200	ACC DEP - NUCL - TURKEY POINT	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
BAL008220	ACC DEP - NUCL - ST LUCIE 1	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
BAL008250	ACC DEP - NUCL - ST LUCIE COM	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
BAL008270	ACC DEP - NUCL - ST LUCIE 2	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
OTHER PRODUCTION:			
BAL008300	ACC DEP - OTHER PRODUCTION	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)

COST OF SERVICE STUDY
COST OF SERVICE METHODOLOGY BY COMPONENT

COSS ID	Description	COSS Methodology	Allocator
BAL008350	ACC DEP - OTHER PROD - DISMANTLEMENT	12CP & 1/13	**Compound Allocator -** FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
TRANSMISSION -			
BAL008400	ACC DEP - TRANSMISSION	12CP & 1/13 adjusted for transmission pulloffs for retail customers	**Compound Allocator -** FPL301 - Transmission Customers Pull-offs (0.2%) FPL101 - Average 12CP Demand (12/13th of 99.8%) FPL201 - MWH Sales (1/13th of 99.8%)
DISTRIBUTION -			
BAL008511	ACC DEP - DIST - ACCT 361 - STRUCT & IMPROV	GCP demand, adjusted for losses, for loads at Primary and Secondary voltage levels only.	FPL104 - Distribution GCP Demand
BAL008512	ACC DEP - DIST - ACCT 362 - STATION EQUIP	GCP demand, adjusted for losses, for loads at Primary and Secondary voltage levels only.	FPL104 - Distribution GCP Demand
BAL008514	ACC DEP - DIST - ACCT 364 - POLES, TOWERS & FIXTURES	Poles, towers and fixtures classified as demand and functionalized between primary and secondary, adjusted for distribution pulloffs for primary and secondary customers.	**Compound Allocator -** FPL302 - Primary Customers Pull-offs (0.3%) FPL104 - Distribution GCP Demand (91.8%) FPL105 - Secondary GCP Demand (7.9%)
BAL008515	ACC DEP - DIST - ACCT 365 - OVERHEAD CONDUCT & DEVIC	Overhead conductors and devices classified as demand and functionalized between primary and secondary, adjusted for distribution pulloffs for primary and secondary customers.	**Compound Allocator -** FPL302 - Primary Customers Pull-offs (0.2%) FPL104 - Distribution GCP Demand (78.8%) FPL105 - Secondary GCP Demand (21.0%)
BAL008516	ACC DEP - DIST - ACCT 366 - UNDERGROUND CONDUIT	Underground conduit classified as demand and functionalized between primary and secondary.	**Compound Allocator -** FPL104 - Distribution GCP Demand (93.9%) FPL105 - Secondary GCP Demand (6.1%)
BAL008517	ACC DEP - DIST - ACCT 367 - UNDERGROUND CONDUCT & DEVIC	Underground conductors and devices classified as demand and functionalized between primary and secondary.	**Compound Allocator -** FPL104 - Distribution GCP Demand (88.1%) FPL105 - Secondary GCP Demand (11.9%)
BAL008518	ACC DEP - DIST - ACCT 368 - LINE TRANSFORMERS	Line transformers, capacitors and network protectors classified as demand and functionalized between primary and secondary.	**Compound Allocator -** FPL104 - Distribution GCP Demand (10.9%) FPL109 - Secondary Customer NCP Demand (89.1%)
BAL008519	ACC DEP - DIST - ACCT 369 - SERVICES	Average number of secondary voltage level customers for retail only, excluding lighting services.	FPL303 - Average Secondary Customers
BAL008520	ACC DEP - DIST - ACCT 370 - METERS	Average number of meters for the rate class multiplied by the average meter unit cost, excluding lighting services.	FPL325 - Meter Costs
BAL008521	ACC DEP - DIST - ACCT 371 - INSTALLS ON CUST PREMISES	100% assignment to Outdoor Lighting.	FPL509 - Outdoor Lighting

COST OF SERVICE STUDY
COST OF SERVICE METHODOLOGY BY COMPONENT

COSS ID	Description	COSS Methodology	Allocator
BAL008523	ACC DEP - DIST - ACCT 373 - STREET LIGHTING & SIGNAL EQUIP	The number of lighting fixtures for the Street Lighting classes only.	FPL508 - Street Lights
GENERAL -			
BAL008600	ACC DEP - GEN PLT - TRANSP EQUIP	Total Labor	LABOR_TOT
BAL008710	ACC DEP - GEN PLT - STRUCTURES	Total Labor	LABOR_TOT
BAL008720	ACC DEP - GEN PLT - OTHER	Total Labor	LABOR_TOT
FUTURE USE PROPERTY			
BAL005100	PLT FUTURE USE - STEAM	Total Plant In Service - Production Steam	P_PLT_STEAM
BAL005200	PLT FUTURE USE - NUCLEAR	Total Plant In Service - Production Nuclear	P_PLT_NUC
BAL005300	PLT FUTURE USE - OTHER PRODUCTION	Total Plant In Service - Other Production	P_PLT_OTH
BAL005400	PLT FUTURE USE - TRANSMISSION	Total Plant In Service - Transmission	T_PLT_TOT
BAL005500	PLT FUTURE USE - DISTRIBUTION	GCP demand, adjusted for losses, for loads at Primary and Secondary voltage levels only.	FPL104 - Distribution GCP Demand
BAL005700	PLT FUTURE USE - GENERAL	Total Plant In Service - General	PLT_GENERAL
CWIP			
INTANGIBLE -			
BAL007000	CWIP - INTANGIBLE	Total Labor	LABOR_TOT
PRODUCTION -			
STEAM:			
BAL007100	CWIP - STEAM	12CP & 1/13	<u>Compound Allocator -</u> FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
NUCLEAR:			
BAL007200	CWIP - NUCLEAR	12CP & 1/13	<u>Compound Allocator -</u> FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
OTHER PRODUCTION:			
BAL007300	CWIP - OTHER PRODUCTION	12CP & 1/13	<u>Compound Allocator -</u> FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
TRANSMISSION -			

COST OF SERVICE STUDY
COST OF SERVICE METHODOLOGY BY COMPONENT

COSS ID	Description	COSS Methodology	Allocator
BAL007400	CWIP - TRANSMISSION	12CP & 1/13 adjusted for transmission pulloffs for retail customers	**Compound Allocator -** FPL301 - Transmission Customers Pull-offs (0.2%) FPL101 - Average 12CP Demand (12/13th of 99.8%) FPL201 - MWH Sales (1/13th of 99.8%)
DISTRIBUTION -			
BAL007500	CWIP - DISTRIBUTION	Total Distribution Plant excluding meters and transformers.	D_PLTEXMTRTX
GENERAL -			
BAL007600	CWIP - GENERAL PLANT	Total Labor	LABOR_TOT
NUCLEAR FUEL			
BAL020600	NUCLEAR FUEL UNDER CAPITAL LEASES	MWH Sales, adjusted for losses.	FPL201 - MWH Sales
WORKING CAPITAL (ASSETS)			
CURRENT AND ACCRUED -			
BAL244000	ACCUM PROVISION FR UNCOLLECTIBLE ACCTS	The 12 month actual Uncollectibles.	FPL205 - Uncollectibles
BAL251000	FUEL STOCK	MWH Sales, adjusted for losses.	FPL201 - MWH Sales
BAL254100	PLANT MATERIALS & OPERATING SUPPLIES	Total Plant In Service - Gross	PLT_GROSS
BAL265600	PREPAYMENTS - INTEREST PAPER & DEBT	Total Plant In Service - Gross	PLT_GROSS
BAL275000	MISC CURR & ACCR ASSETS - DERIVATIVES	MWH Sales, adjusted for losses.	FPL201 - MWH Sales
ALL OTHER		Total O&M Expenses	OM_TOT
DEFERRED DEBITS -			
BAL382315	OTHER REG ASSETS - NUCLEAR G/U CARRYING COSTS	Total Plant In Service - Production Nuclear	P_PLT_NUC
BAL382321	OTHER REG ASSETS - DERIVATIVES	MWH Sales, adjusted for losses.	FPL201 - MWH Sales
BAL382351	OTHER REG ASSETS - STORM SECURIZATION - BONDS	Plant In Service - Transmission & Distribution	PLT_TD
BAL382352	OTHER REG ASSETS - STORM SECURIZATION - DEFERRED TAX	Plant In Service - Transmission & Distribution	PLT_TD
BAL386190	MISC DEFD DEB - DEFD PENSION DEBIT	Total Labor	LABOR_TOT
BAL386415	MISC DEFD DEB - SJRPP	Total Plant In Service - Production Steam	P_PLT_STEAM
ALL OTHER		Total O&M Expenses	OM_TOT

COST OF SERVICE STUDY
COST OF SERVICE METHODOLOGY BY COMPONENT

BALANCE SHEET - LIABILITIES

PROPRIETARY CAPITAL
LONG-TERM DEBT
OTHER NONCURRENT LIABILITIES

COSS ID	Description	COSS Methodology	Allocator
BAL628200	ACCUM PROV INJURIES & DAMAGES - WORKERS COMPENSATION	Total Labor	LABOR_TOT
BAL628370	ACCUM PROV PEN/BENFS - POST RETIREMENT BENEFITS	Total Labor	LABOR_TOT
BAL628411	ACC MISC OPER PROV - NUCLEAR MAINT RESERVE	MWH Sales, adjusted for losses.	FPL201 - MWH Sales
BAL628430	ACC MISC OPER PROV - DEFD COMPENSATION	Total Labor	LABOR_TOT
ALL OTHER		Total O&M Expenses	OM_TOT

WORKING CAPITAL (LIABILITIES)
CURRENT AND ACCRUED LIABILITIES -

COSS ID	Description	COSS Methodology	Allocator
BAL736205	TAXES ACCRUED - CITY & COUNTY REAL & PERSONAL PROPERTY	Total Plant In Service - Net	PLT_NET
BAL737151	INTEREST ACCRUED ON LONG - TERM DEBT - STORM SECURIZATION	Plant In Service - Transmission & Distribution	PLT_TD
BAL742720	MISC CURR & ACC LIAB - NUCL ASS D&D - CURRENT	Total Plant In Service - Production Nuclear	P_PLT_NUC
BAL742800	MISC CURR & ACC LIAB - POLE ATTACHMENT RENTALS	Poles, towers and fixtures classified as demand and functionalized between primary and secondary, adjusted for distribution pulloffs for primary and secondary customers.	<u>Compound Allocator -</u> FPL302 - Primary Customers Pull-offs (0.3%) FPL104 - Distribution GCP Demand (91.8%) FPL105 - Secondary GCP Demand (7.9%)
BAL744000	MISC CURR & ACC LIAB - DERIVATIVES LIABILITY	MWH Sales, adjusted for losses.	FPL201 - MWH Sales
ALL OTHER		Total O&M Expenses	OM_TOT

DEFERRED CREDITS -

COSS ID	Description	COSS Methodology	Allocator
BAL853182	OTHER DEFD CREDITS - STORM LIABILITIES	Total Plant In Service - Gross	PLT_GROSS
BAL853250	OTHER DEFD CREDITS - DEFD SJRPP INTEREST	Total Plant In Service - Production Steam	P_PLT_STEAM
BAL854401	OTHER REG LIAB - NUCLEAR AMORTIZATION	Total Plant In Service - Production Nuclear	P_PLT_NUC
ALL OTHER		Total O&M Expenses	OM_TOT

COST OF SERVICE STUDY
COST OF SERVICE METHODOLOGY BY COMPONENT

COSS ID	Description	COSS Methodology	Allocator

INCOME STATEMENT

OPERATING REVENUES

SALES OF ELECTRICITY -

COSS ID	Description	COSS Methodology	Allocator
INC040000	RETAIL SALES - BASE REVENUES	Retail Base Revenues.	FPL401 - Base Revenues
INC040350	GROSS RECEIPTS TAX REVENUES	Retail Base Revenues.	FPL401 - Base Revenues
INC040420	CILC INCENTIVES OFFSET	Incentive revenue offset dollars, collected through ECCR, for each of the CILC and ISST customers.	FPL402 - LOAD CONTROL INCENTIVE OFFSET
INC056920	OTHER ELECTRIC REVS - UNBILLED REVENUES - FPSC	Retail Base Revenues.	FPL401 - Base Revenues

OTHER OPERATING REVENUES -

COSS ID	Description	COSS Methodology	Allocator
INC050400	FIELD COLLECTION LATE PAYMENT CHARGES	Projected field collections charge (account 450.400) and late payment charge (account 450.500) by rate class.	FPL311 - MISC SERV REVS - FIELD COLLECTION - LATE PAYMENT
INC051010	MISC SERVICE REVS - INITIAL CONNECTION	Projected initial service charge (account 451.000) by rate class.	FPL312 - MISC SERV REVS - INITIAL CONNECTION
INC051020	MISC SERVICE REVS - RECONNECT AFTER NON PAYMENT	Projected reconnect charge (account 451.000) by rate class.	FPL313 - MISC SERV REVS - RECONNECTION
INC051030	MISC SERVICE REVS - CONNECT / DISCONNECT	Projected connection service charge (account 451.000) by rate class.	FPL314 - MISC SERV REVS - CONNECTION OF EXISTING ACCOUNT
INC051040	MISC SERVICE REVS - RETURNED CUSTOMER CHECKS	Projected returned check charges by rate class.	FPL315 - Misc Serv Revs - Returned Check Charges
INC051050	MISC SERVICE REVS - CURRENT DIVERSION PENALTY	Projected current diversion charges (account 451.000) by rate class.	FPL316 - MISC SERV REVS - CURRENT DIVERSION
INC051060	MISC SERVICE REVS - OTHER BILLINGS	Miscellaneous Service Revenues	MISC_SVC_REV
INC051100	MISC SERVICE REVS - OTH REIMBURSEMENTS	Total Distribution Plant In Service	D_PLT_TOT
INC054000	RENT FROM ELECT PROP - GENERAL	Telephone and cable TV rental income allocated based on "Account 364 - Poles, Towers & Fixtures". Other rental income is allocated based on "Gross Plant".	**Compound Allocator -** FPL104 - Distribution GCP Demand (56.6%) FPL101 - Average 12CP Demand (28.1%) FPL105 - Secondary GCP Demand (5.0%) FPL109 - Secondary Customer NCP Demand (3.2%) FPL201 - MWH Sales (2.9%) Other Allocators (4.2%)
INC054100	RENT FROM ELECT PROP - FUTURE USE & PLT IN SERV & STORAGE	Total Plant In Service - Net	PLT_NET

COST OF SERVICE STUDY

COST OF SERVICE METHODOLOGY BY COMPONENT

COSS ID	Description	COSS Methodology	Allocator
INC054400	RENT FROM ELECT PROP - POLE ATTACHMENTS	Poles, towers and fixtures classified as demand and functionalized between primary and secondary, adjusted for distribution pulloffs for primary and secondary customers.	**Compound Allocator -** FPL302 - Primary Customers Pull-offs (0.3%) FPL104 - Distribution GCP Demand (91.8%) FPL105 - Secondary GCP Demand (7.9%)
INC056130	OTHER ELECTRIC REVS - TRANSMISSION	12CP & 1/13	**Compound Allocator -** FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
INC056700	OTHER ELECTRIC REVS - MISC	Total O&M Expenses	OM_TOT

OPERATION AND MAINTENANCE EXPENSES

POWER PRODUCTION EXPENSES -

STEAM POWER GENERATION:

COSS ID	Description	COSS Methodology	Allocator
INC100000	STEAM POWER - OPERATION SUPERVISION & ENGINEERING	Classified between demand and energy on the basis of the relative proportions of labor costs contained in accounts 501 thru 507.	Compound Allocator - FPL101 - Average 12CP Demand (94.4%) FPL201 - MWH Sales (5.6%)
INC101110	STEAM POWER - FUEL - OIL, GAS & COAL	MWH Sales, adjusted for losses.	FPL201 - MWH Sales
INC101210	STEAM POWER - FUEL - NON RECOVERABLE OIL	MWH Sales, adjusted for losses.	FPL201 - MWH Sales
INC102000	STEAM POWER - STEAM EXP	Labor amount in account 502 is classified as demand. The remainder in account 502 is classified as energy.	Compound Allocator - FPL101 - Average 12CP Demand (52.7%) FPL201 - MWH Sales (47.3%)
INC105000	STEAM POWER - ELECTRIC EXP	Labor amount in account 505 is classified as demand. The remainder in account 505 is classified as energy.	Compound Allocator - FPL101 - Average 12CP Demand (79.7%) FPL201 - MWH Sales (20.3%)
INC106000	STEAM POWER - MISC STEAM POWER EXP.	Average 12 CP Demands, adjusted for losses.	FPL101 - Average 12CP Demand
INC106310	STEAM POWER - MISC - ADDITIONAL SECURITY	Average 12 CP Demands, adjusted for losses.	FPL101 - Average 12CP Demand
INC107000	STEAM POWER - RENTS	Average 12 CP Demands, adjusted for losses.	FPL101 - Average 12CP Demand
INC110000	STEAM POWER - MAINT SUPERVISION & ENGINEERING	Classified between demand and energy on the basis of the relative proportions of labor costs contained in accounts 511 thru 514.	Compound Allocator - FPL101 - Average 12CP Demand (2.9%) FPL201 - MWH Sales (97.1%)
1 INC111000	STEAM POWER - MAINTENANCE OF STRUCTURES	Average 12 CP Demands, adjusted for losses.	FPL101 - Average 12CP Demand
INC112000	STEAM POWER - MAINT OF BOILER PLANT	MWH Sales, adjusted for losses.	FPL201 - MWH Sales
INC113000	STEAM POWER - MAINT OF ELECTRIC PLANT	MWH Sales, adjusted for losses.	FPL201 - MWH Sales

COST OF SERVICE STUDY

COST OF SERVICE METHODOLOGY BY COMPONENT

COSS ID	Description	COSS Methodology	Allocator
INC114000	STEAM POWER - MAINT OF MISCELLANEOUS STEAM PLT	MWH Sales, adjusted for losses.	FPL201 - MWH Sales
NUCLEAR POWER GENERATION:			
INC117000	NUCL POWER - OPERATION SUPERVISION & ENGINEERING	Classified between demand and energy on the basis of the relative proportions of labor costs contained in accounts 518 thru 525.	**Compound Allocator -** FPL101 - Average 12CP Demand (99.5%) FPL201 - MWH Sales (0.5%)
INC118180	NUCL POWER - NUC FUEL EXP - ADDITIONAL SECURITY	MWH Sales, adjusted for losses.	FPL201 - MWH Sales
INC118210	NUCL POWER - NUC FUEL EXP - NON RECOVERABLE FUEL EXP	MWH Sales, adjusted for losses.	FPL201 - MWH Sales
INC119000	NUCL POWER - COOLANTS AND WATER	Labor amount in account 519 is classified as demand. The remainder in account 519 is classified as energy.	**Compound Allocator -** FPL101 - Average 12CP Demand (31.3%) FPL201 - MWH Sales (68.7%)
INC120000	NUCL POWER - STEAM EXP	Labor amount in account 520 is classified as demand. The remainder in account 520 is classified as energy.	**Compound Allocator -** FPL101 - Average 12CP Demand (71.0%) FPL201 - MWH Sales (29.0%)
INC123000	NUCL POWER - ELECTRIC EXP	Labor amount in account 523 is classified as demand. The remainder in account 523 is classified as energy.	**Compound Allocator -** FPL101 - Average 12CP Demand (0.0%) FPL201 - MWH Sales (100.0%)
INC124000	NUCL POWER - MISC NUCLEAR POWER EXP	Average 12 CP Demands, adjusted for losses.	FPL101 - Average 12CP Demand
INC128000	NUCL POWER - MAINT SUPERVISION & ENGINEERING	Classified between demand and energy on the basis of the relative proportions of labor costs contained in accounts 529 thru 532.	**Compound Allocator -** FPL101 - Average 12CP Demand (0.1%) FPL201 - MWH Sales (99.9%)
INC129000	NUCL POWER - MAINT OF STRUCTURES	Average 12 CP Demands, adjusted for losses.	FPL101 - Average 12CP Demand
INC130000	NUCL POWER - MAINT OF REACTOR PLANT	MWH Sales, adjusted for losses.	FPL201 - MWH Sales
INC131000	NUCL POWER - MAINTENANCE OF ELECTRIC PLANT	MWH Sales, adjusted for losses	FPL201 - MWH Sales
INC132000	NUCL POWER - MAINT OF MISC NUCLEAR PLANT	MWH Sales, adjusted for losses.	FPL201 - MWH Sales
OTHER POWER GENERATION:			
INC146000	OTH POWER - OPERATION SUPERVISION & ENGINEERING	Average 12 CP Demands, adjusted for losses.	FPL101 - Average 12CP Demand
INC147200	OTH POWER - FUEL -NON RECOVERABLE ANNUAL EMISSIONS FEE	MWH Sales, adjusted for losses.	FPL201 - MWH Sales
INC148000	OTH POWER - GENERATION EXP	Average 12 CP Demands, adjusted for losses.	FPL101 - Average 12CP Demand
INC149000	OTH POWER - MISC OTHER POWER GENERATION EXP	Average 12 CP Demands, adjusted for losses.	FPL101 - Average 12CP Demand

COST OF SERVICE STUDY
COST OF SERVICE METHODOLOGY BY COMPONENT

COSS ID	Description	COSS Methodology	Allocator
INC151000	OTH POWER - MAINT SUPERVISION & ENGINEERING	Average 12 CP Demands, adjusted for losses.	FPL101 - Average 12CP Demand
INC152000	OTH POWER - MAINT OF STRUCTURES	Average 12 CP Demands, adjusted for losses.	FPL101 - Average 12CP Demand
INC153000	OTH POWER - MAINT GENERATING & ELECTRIC PLANT	Average 12 CP Demands, adjusted for losses.	FPL101 - Average 12CP Demand
INC154000	OTH POWER - MAINT MISC OTHER POWER GENERATION	Average 12 CP Demands, adjusted for losses.	FPL101 - Average 12CP Demand
OTHER POWER SUPPLY:			
INC155250	OTH POWER - SJRPP - FPSC - 88TSR	Average 12 CP Demands, adjusted for losses.	FPL101 - Average 12CP Demand
INC156000	OTH POWER - SYSTEM CONTROL AND LOAD DISPATCHING	Average 12 CP Demands, adjusted for losses.	FPL101 - Average 12CP Demand
INC157000	OTH POWER - OTHER EXP	Average 12 CP Demands, adjusted for losses.	FPL101 - Average 12CP Demand
TRANSMISSION EXPENSES -			
INC260010	TRANS EXP - OPERATION SUPERVISION & ENGINEERING	12CP & 1/13 adjusted for transmission pulloffs for retail customers	Compound Allocator - FPL301 - Transmission Customers Pull-offs (0.2%) FPL101 - Average 12CP Demand (12/13th of 99.8%) FPL201 - MWH Sales (1/13th of 99.8%)
INC261000	TRANS EXP - LOAD DISPATCHING	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
INC262000	TRANS EXP - STATION EXP	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
INC263000	TRANS EXP - OVERHEAD LINE EXP	12CP & 1/13 adjusted for transmission pulloffs for retail customers	Compound Allocator - FPL301 - Transmission Customers Pull-offs (0.2%) FPL101 - Average 12CP Demand (12/13th of 99.8%) FPL201 - MWH Sales (1/13th of 99.8%)
INC265000	TRANS EXP - TRANSMISSION OF ELECTRICITY BY OTHERS	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
INC265200	TRANS EXP - TRANSMISSION OF ELECTRICITY - RTO	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
INC266000	TRANS EXP - MISC TRANS EXP	12CP & 1/13 adjusted for transmission pulloffs for retail customers	Compound Allocator - FPL301 - Transmission Customers Pull-offs (0.2%) FPL101 - Average 12CP Demand (12/13th of 99.8%) FPL201 - MWH Sales (1/13th of 99.8%)

COST OF SERVICE STUDY
COST OF SERVICE METHODOLOGY BY COMPONENT

COSS ID	Description	COSS Methodology	Allocator
INC268010	TRANS EXP - MAINT SUPERVISION & ENGINEERING	12CP & 1/13 adjusted for transmission pulloffs for retail customers	<u>Compound Allocator -</u> FPL301 - Transmission Customers Pull-offs (0.2%) FPL101 - Average 12CP Demand (12/13th of 99.8%) FPL201 - MWH Sales (1/13th of 99.8%)
INC269000	TRANS EXP - MAINT OF STRUCTURES	12CP & 1/13	<u>Compound Allocator -</u> FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
INC270000	TRANS EXP - MAINT OF STATION EQUIP	12CP & 1/13	<u>Compound Allocator -</u> FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
INC271000	TRANS EXP - MAINT OF OVERHEAD LINES	12CP & 1/13 adjusted for transmission pulloffs for retail customers	<u>Compound Allocator -</u> FPL301 - Transmission Customers Pull-offs (0.2%) FPL101 - Average 12CP Demand (12/13th of 99.8%) FPL201 - MWH Sales (1/13th of 99.8%)
INC272000	TRANS EXP - MAINT OF UNDERGROUND LINES	12CP & 1/13 adjusted for transmission pulloffs for retail customers	<u>Compound Allocator -</u> FPL301 - Transmission Customers Pull-offs (0.2%) FPL101 - Average 12CP Demand (12/13th of 99.8%) FPL201 - MWH Sales (1/13th of 99.8%)
INC273000	TRANS EXP - MAINT OF MISC TRANS PLANT	12CP & 1/13 adjusted for transmission pulloffs for retail customers	<u>Compound Allocator -</u> FPL301 - Transmission Customers Pull-offs (0.2%) FPL101 - Average 12CP Demand (12/13th of 99.8%) FPL201 - MWH Sales (1/13th of 99.8%)
DISTRIBUTION EXPENSES -			
INC380000	DIST EXP - OPERATION SUPERVISION AND ENGINEERING	Total Distribution Plant In Service	D_PLT_TOT
INC381000	DIST EXP - LOAD DISPATCHING	GCP demand, adjusted for losses, for loads at Primary and Secondary voltage levels only.	FPL104 - Distribution GCP Demand
INC382000	DIST EXP - SUBSTATION EXP	GCP demand, adjusted for losses, for loads at Primary and Secondary voltage levels only.	FPL104 - Distribution GCP Demand
INC383000	DIST EXP - OVERHEAD LINE EXP	The overhead amount in plant acct 369 (Services) is divided by the total of the balances in plant accts 364 and 365 and the overhead amount in acct 369. This ratio is multiplied times the balance in acct 583 and is classified as services. The remainder is classified as demand (either primary or secondary based on the ratio of primary and secondary in plant accts 364 and 365).	<u>Compound Allocator -</u> FPL303 - Average Secondary Customers (8.2%) FPL104 - Distribution GCP Demand (77.5%) FPL105 - Secondary GCP Demand (14.3%)

COST OF SERVICE STUDY
COST OF SERVICE METHODOLOGY BY COMPONENT

COSS ID	Description	COSS Methodology	Allocator
INC384000	DIST EXP - UNDERGROUND LINE EXP	The underground amount in plant acct 369 (Services) is divided by the total of the balances in plant accts 366 and 367 and the underground amount in plant acct 369. This ratio is multiplied times the balance in acct 584 and is classified as services. The remainder is classified as demand (either primary or secondary based on the ratio of primary and secondary in plant accts 366 and 367).	**Compound Allocator -** FPL303 - Average Secondary Customers (18.1%) FPL104 - Distribution GCP Demand (74.0%) FPL105 - Secondary GCP Demand (7.9%)
INC385000	DIST EXP - STREET LIGHTING AND SIGNAL SYSTEM EXP	The number of lighting fixtures for the Street Lighting classes only.	FPL508 - Street Lights
INC386000	DIST EXP - METER EXP	Average number of meters for the rate class multiplied by the average meter unit cost, excluding lighting services.	FPL325 - Meter Costs
INC387000	DIST EXP - CUSTOMER INSTALLATIONS EXP	Outdoor Lighting installation expenses classified as lighting. The remainder is classified as customer.	**Compound Allocator -** FPL509 - Outdoor Lighting (48.0%) FPL310 - Average Distribution Customers - Retail (52.0%)
INC388000	DIST EXP - MISCELLANEOUS DISTRIBUTION EXP	Total Distribution Plant In Service	D_PLT_TOT
INC389000	DIST EXP - RENTS	Total Distribution Plant In Service	D_PLT_TOT
INC390000	DIST EXP - MAINT SUPERVISION AND ENGINEERING	Total Distribution Plant In Service	D_PLT_TOT
INC391000	DIST EXP - MAINT OF STRUCTURES	GCP demand, adjusted for losses, for loads at Primary and Secondary voltage levels only.	FPL104 - Distribution GCP Demand
INC392000	DIST EXP - MAINT OF STATION EQUIP	GCP demand, adjusted for losses, for loads at Primary and Secondary voltage levels only.	FPL104 - Distribution GCP Demand
INC393000	DIST EXP - MAINT OF OVERHEAD LINES	The overhead amount in plant acct 369 (Services) is divided by the total of the balances in plant accts 364 and 365 and the overhead amount in acct 369. This ratio is multiplied times the balance in acct 593 and is classified as services. The remainder is classified as demand (either primary or secondary based on the ratio of primary and secondary in plant accts 364 and 365).	**Compound Allocator -** FPL303 - Average Secondary Customers (8.2%) FPL104 - Distribution GCP Demand (77.5%) FPL105 - Secondary GCP Demand (14.3%)
INC394000	DIST EXP - MAINT OF UNDERGROUND LINES	The underground amount in plant acct 369 (Services) is divided by the total of the balances in plant accts 366 and 367 and the underground amount in plant acct 369. This ratio is multiplied times the balance in acct 594 and is classified as services. The remainder is classified as demand (either primary or secondary based on the ratio of primary and secondary in plant accts 366 and 367).	**Compound Allocator -** FPL303 - Average Secondary Customers (18.1%) FPL104 - Distribution GCP Demand (74.0%) FPL105 - Secondary GCP Demand (7.9%)

COST OF SERVICE STUDY
COST OF SERVICE METHODOLOGY BY COMPONENT

COSS ID	Description	COSS Methodology	Allocator
INC395000	DIST EXP - MAINT OF LINE TRANSFORMERS	Line transformers, capacitors and network protectors classified as demand and functionalized between primary and secondary.	**Compound Allocator -** FPL104 - Distribution GCP Demand (10.9%) FPL109 - Secondary Customer NCP Demand (89.1%)
INC396000	DIST EXP - MAINT OF STREET LIGHTING & SIGNAL SYSTEMS	The number of lighting fixtures for the Street Lighting classes only.	FPL508 - Street Lights
INC397000	DIST EXP - MAINT OF METERS	Average number of meters for the rate class multiplied by the average meter unit cost, excluding lighting services.	FPL325 - Meter Costs
INC398000	DIST EXP - MAINT OF MISC DISTRIBUTION PLANT	Outdoor lights maintenance in acct 598 is assigned to outdoor lighting. The remainder is allocated based on distribution plant in service.	**Compound Allocator -** FPL509 - Outdoor Lighting (29.3%) Plant in Service - Distribution (70.7%)
CUSTOMER ACCOUNTS EXPENSES -			
INC401000	CUST ACCT EXP - SUPERVISION	Based on the allocation of Customers Account Expense accounts (INC402000, INC403000, INC404000 & INC405000).	CA_ACCTS_SUPER
INC402000	CUST ACCT EXP - METER READING EXP	Average number of customers multiplied by average meter and SSDR material unit cost. The non-metered rate classes are zero.	FPL330 - Meter and SSDR Material Costs
INC403000	CUST ACCT EXP - CUSTOMER RECORDS AND COLLECTION EXP	Average number of customers for retail rate classes only.	FPL356 - Average Customers
INC404000	CUST ACCT EXP - UNCOLLECTIBLE ACCTS	The 12 month actual Uncollectibles.	FPL205 - Uncollectibles
CUSTOMER SERVICE & INFORMATIONAL EXP -			
INC407000	CUST SERV & INFO - SUPERVISION	Average number of customers for retail rate classes only.	FPL356 - Average Customers
INC408000	CUST SERV & INFO - CUST ASSISTANCE EXP	Average number of customers for retail rate classes only.	FPL356 - Average Customers
INC409000	CUST SERV & INFO - INFO & INST ADV - GENERAL	Average number of customers for retail rate classes only.	FPL356 - Average Customers
INC410000	CUST SERV & INFO - MISC CUST SERVICE & INFO EXP	Average number of customers for retail rate classes only.	FPL356 - Average Customers
SALES EXPENSES -			
INC411000	SUPERVISION-SALES EXP	Average number of customers for retail rate classes only.	FPL356 - Average Customers
INC516000	MISCELLANEOUS AND SELLING EXP	Average number of customers for retail rate classes only.	FPL356 - Average Customers
ADMINISTRATIVE AND GENERAL EXPENSES -			
INC520010	A&G EXP - SALARIES	Total Labor	LABOR_TOT
INC521000	A&G EXP - OFFICE SUPPLIES AND EXP	Total Labor	LABOR_TOT
INC522000	A&G EXP - ADMINISTRATIVE EXP TRANSFERRED CR.	Total Labor	LABOR_TOT

COST OF SERVICE STUDY
COST OF SERVICE METHODOLOGY BY COMPONENT

COSS ID	Description	COSS Methodology	Allocator
INC523000	A&G EXP - OUTSIDE SERVICES EMPLOYED	Total Labor	LABOR_TOT
INC524000	A&G EXP - PROPERTY INSURANCE	Total Plant In Service - Gross	PLT_GROSS
INC525000	A&G EXP - INJURIES AND DAMAGES	Total Labor	LABOR_TOT
INC526100	A&G EXP - EMP PENSIONS & BENEFITS	Total Labor	LABOR_TOT
INC526110	A&G EXP - EMP PENSIONS & BENEFITS - FUEL	Total Labor	LABOR_TOT
INC528010	A&G EXP - REGULATORY COMMISSION EXPENSE - FPSC	Total Labor	LABOR_TOT
INC530000	A&G EXP - MISC GENERAL EXP	Total Labor	LABOR_TOT
INC531000	A&G EXP - RENTS	Total Labor	LABOR_TOT
INC535000	A&G EXP - MAINT OF GENERAL PLANT	Total Plant in Service - General	PLT_GENERAL
DEPRECIATION EXPENSES			
INTANGIBLE -			
INC603000	DEPR EXP - INTANGIBLE	Total Labor	LABOR_TOT
INC603001	DEPR EXP - INTANGIBLE - ASSET RETIR OBLIG	Total Labor	LABOR_TOT
PRODUCTION -			
STEAM:			
INC603010	DEPR EXP - STEAM	12CP & 1/13	**Compound Allocator -** FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
INC603011	DEPR EXP - FOSSIL DECOMMISSIONING	Total Plant In Service - Production Steam	P_PLT_STEAM
INC603980	DEPR EXP - AMORT OF ELECTRIC PLANT - ACQ ADJUSTMENT	12CP & 1/13	**Compound Allocator -** FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
NUCLEAR:			
INC603020	DEPR EXP - TURKEY POINT	12CP & 1/13	**Compound Allocator -** FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)

COST OF SERVICE STUDY
COST OF SERVICE METHODOLOGY BY COMPONENT

COSS ID	Description	COSS Methodology	Allocator
INC603022	DEPR EXP - ST LUCIE 1	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
INC603024	DEPR EXP - ST LUCIE COMMON	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
INC603026	DEPR EXP - ST LUCIE 2	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
OTHER PRODUCTION:			
INC603030	DEPR EXP - OTHER PRODUCTION	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
INC603036	DEPR EXP - OTHER PRODUCTION - DISMANTLEMENT	12CP & 1/13	Compound Allocator - FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
TRANSMISSION -			
INC603041	DEPR EXP - TRANSMISSION	12CP & 1/13 adjusted for transmission pulloffs for retail customers	Compound Allocator - FPL301 - Transmission Customers Pull-offs (0.2%) FPL101 - Average 12CP Demand (12/13th of 99.8%) FPL201 - MWH Sales (1/13th of 99.8%)
DISTRIBUTION -			
INC603051	DEPR EXP - DIST - ACCT 361 - STRUCT & IMPROV	GCP demand, adjusted for losses, for loads at Primary and Secondary voltage levels only.	FPL104 - Distribution GCP Demand
INC603052	DEPR EXP - DIST - ACCT 362 - STATION EQUIP	GCP demand, adjusted for losses, for loads at Primary and Secondary voltage levels only.	FPL104 - Distribution GCP Demand
INC603054	DEPR EXP - DIST - ACCT 364 - POLES, TOWERS & FIXTURES	Poles, towers and fixtures classified as demand and functionalized between primary and secondary, adjusted for distribution pulloffs for primary and secondary customers.	Compound Allocator - FPL302 - Primary Customers Pull-offs (0.3%) FPL104 - Distribution GCP Demand (91.8%) FPL105 - Secondary GCP Demand (7.9%)
INC603055	DEPR EXP - DIST - ACCT 365 - OVERHEAD CONDUCT & DEVIC	Overhead conductors and devices classified as demand and functionalized between primary and secondary, adjusted for distribution pulloffs for primary and secondary customers.	Compound Allocator - FPL302 - Primary Customers Pull-offs (0.2%) FPL104 - Distribution GCP Demand (78.8%) FPL105 - Secondary GCP Demand (21.0%)

COST OF SERVICE STUDY
COST OF SERVICE METHODOLOGY BY COMPONENT

COSS ID	Description	COSS Methodology	Allocator
INC803056	DEPR EXP - DIST - ACCT 366 - UNDERGROUND CONDUIT	Underground conduit classified as demand and functionalized between primary and secondary.	**Compound Allocator -** FPL104 - Distribution GCP Demand (93.9%) FPL105 - Secondary GCP Demand (6.1%)
INC803057	DEPR EXP - DIST - ACCT 367 - UNDERGROUND CONDUCT & DEVIC	Underground conductors and devices classified as demand and functionalized between primary and secondary.	**Compound Allocator -** FPL104 - Distribution GCP Demand (88.1%) FPL105 - Secondary GCP Demand (11.9%)
INC803058	DEPR EXP - DIST - ACCT 368 - LINE TRANSFORMERS	Line transformers, capacitors and network protectors classified as demand and functionalized between primary and secondary.	**Compound Allocator -** FPL104 - Distribution GCP Demand (10.9%) FPL109 - Secondary Customer NCP Demand (89.1%)
INC803059	DEPR EXP - DIST - ACCT 369 - SERVICES	Average number of secondary voltage level customers for retail only, excluding lighting services.	FPL303 - Average Secondary Customers
INC803060	DEPR EXP - DIST - ACCT 370 - METERS	Average number of meters for the rate class multiplied by the average meter unit cost, excluding lighting services.	FPL325 - Meter Costs
INC803061	DEPR EXP - DIST - ACCT 371 - INSTALLS ON CUST PREMISES	100% assignment to Outdoor Lighting.	FPL509 - Outdoor Lighting
INC803063	DEPR EXP - DIST - ACCT 373 - STREET LIGHTING & SIGNAL EQUIP	The number of lighting fixtures for the Street Lighting classes only.	FPL508 - Street Lights
GENERAL -			
INC803091	DEPR EXP - GENERAL - STRUCTURES	Total Labor	LABOR_TOT
INC803093	DEPR EXP - GENERAL - OTHER	Total Labor	LABOR_TOT
NUCLEAR DECOMMISSIONING EXPENSE -			
INC803310	DEPR EXP - NUCL DECOM	12CP & 1/13	**Compound Allocator -** FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
INC803371	DEPR EXP - NUCL DECOM - ASSET RETIR OBLIG	12CP & 1/13	**Compound Allocator -** FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
AMORT OF PROPERTY LOSSES, UNRECOVERED PLANT & REGULATORY STUDY COSTS			
INC805000	ACCRETION EXPENSE - ASSET RETIR OBLIG REGULATORY DEBIT	Total Labor	LABOR_TOT
INC807000	AMORT OF PROP LOSSES, UNRECOV PLT & REGUL STUDY COSTS	Adjusted Rate Base	RATE_BASE
INC807143	REGULATORY CREDIT - ASSET RETIR OBLIG	Total Labor	LABOR_TOT

COST OF SERVICE STUDY
COST OF SERVICE METHODOLOGY BY COMPONENT

COSS ID	Description	COSS Methodology	Allocator
INC607360	AMORTIZATION OF NUCLEAR RESERVE	12CP & 1/13	**Compound Allocator :** FPL101 - Average 12CP Demand (12/13th) FPL201 - MWH Sales (1/13th)
INC607365	AMORTIZATION OF DBT DEFERRED SECURITY	Total O&M Expenses	OM_TOT
TAXES OTHER THAN INCOME TAXES			
INC608100	TAX OTHER THAN INC TAX - UTILITY OPERAT INCOME CLEARING	Total Plant In Service - Net	PLT_NET
INC608105	TAX OTHER TH INC TAX - REAL & PERS PROPERTY TAX	Total Plant In Service - Net	PLT_NET
INC608115	TAX OTHER TH INC TAX - FEDERAL UNEMPLOYMENT TAXES	Total Labor	LABOR_TOT
INC608120	TAX OTHER TH INC TAX - STATE UNEMPLOYMENT TAXES	Total Labor	LABOR_TOT
INC608125	TAX OTHER TH INC TAX - FICA (SOCIAL SECURITY)	Total Labor	LABOR_TOT
INC608135	TAX OTHER TH INC TAX - REG ASSESS FEE - RETAIL BASE	Retail Base Revenues.	FPL401 - Base Revenues
INCOME TAXES			
INC609100	INCOME TAXES - UTILITY OPER INCOME - CURRENT FEDERAL	Pretax Book Income	PRETAX_INC
INC609110	INCOME TAXES - UTILITY OPER INCOME - CURRENT STATE	Pretax Book Income	PRETAX_INC
PROVISION FOR DEFERRED INCOME TAXES			
INC610000	INCOME TAXES - DEFD FEDERAL	Pretax Book Income	PRETAX_INC
INC611000	INCOME TAXES - DEFD STATE	Pretax Book Income	PRETAX_INC
INVESTMENT TAX CREDIT			
INC611450	AMORTIZATION OF INVESTMENT TAX CREDIT	Total Plant In Service - Net	PLT_NET
GAINS (LOSSES) FROM DISPOSITIONS			
INC611600	GAIN FROM DISP OF UTILITY PLANT	GCP demand, adjusted for losses, for loads at Primary and Secondary voltage levels only.	FPL104 - Distribution GCP Demand

Docket No. 080677-EI
Rates of Return and Parity at Present Rates
Exhibit JAE-5, Page 1 of 2

Rates of Return and Parity at Present Rates

For the Test Year 2010
($ Millions)

(1)	(2)	(3)	(4)	(6)	(7)	(8)
	Revenues from Sales - at Present Rates					
Rate Class	Achieved Revenues (1)	Rate of Return (ROR) (1)	Parity Index (1)	Equalized Revenue Requirements (2)	Revenue Excess/ (Deficiency) (2) - (6)	Percent Difference (7) / (2)
Above Parity -						
RS(T)-1	$2,315.9	4.5%	107%	$2,269.1	$46.9	2.0%
GS(T)-1	289.9	6.4%	150%	252.9	37.0	12.8%
SL-1	68.9	4.3%	102%	68.7	0.3	0.4%
All Other (5 Classes)	24.0	N/A	N/A	20.7	3.3	13.8%
Below Parity -						
GSD(T)-1	$741.5	4.1%	96%	$750.7	($9.2)	-1.2%
GSLD(T)-1	141.7	2.5%	58%	163.5	(21.8)	-15.4%
HLFT-2	115.4	1.5%	34%	145.6	(30.1)	-26.1%
CILC-1D	71.4	2.9%	67%	79.4	(8.0)	-11.2%
HLFT-1	34.8	3.3%	79%	37.3	(2.5)	-7.1%
CILC-1T	25.2	2.7%	64%	28.1	(2.8)	-11.2%
HLFT-3	23.5	1.5%	35%	29.5	(6.0)	-25.5%
GSLD(T)-2	20.9	2.8%	66%	23.4	(2.5)	-11.8%
SDTR-2	15.5	2.3%	53%	18.3	(2.8)	-17.9%
SDTR-1	15.4	3.8%	90%	15.9	(0.5)	-3.2%
All Other (7 Classes)	16.8	N/A	N/A	18.1	(1.2)	-7.3%
Total Revenues from Sales	$3,920.9	4.3%	100%	$3,920.9	$0.0	100%
Misc Service Charges	76.2			76.2		
Other Operating Revenues	117.6			117.6		
Total Operating Revenues	$4,114.7			$4,114.7		

Notes:
(1) Provided on MFR E-1, Achieved at Present Rates.
(2) Provided on MFR E-1, Equalized at Present Rates.
N/A = Not Applicable

Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 158
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Joseph A. Ender (JAE-5)
DATE 09/05/09

Rates of Return and Parity at Present Rates

For the Subsequent Year 2011
($ Millions)

(1)	(2)	(3)	(4)	(5)	(7)	(8)
		Revenues from Sales - at Present Rates				
Rate Class	Achieved Revenues [1]	Rate of Return (ROR) [1]	Parity Index [1]	Equalized Revenue Requirements [2]	Revenue Excess/ (Deficiency) (2) - (6)	Percent Difference (7) / (2)
Above Parity -						
RS(T)-1	$2,327.0	4.0%	107%	$2,286.5	$40.5	1.7%
GS(T)-1	298.2	5.5%	149%	264.0	34.2	11.5%
SL-1	70.8	4.1%	111%	69.4	1.5	2.1%
All Other (5 Classes)	23.9	N/A	N/A	20.9	3.0	12.5%
Below Parity -						
GSD(T)-1	$763.0	3.6%	96%	$770.6	($7.6)	-1.0%
GSLD(T)-1	144.7	2.1%	58%	165.0	(20.2)	-14.0%
HLFT-2	119.9	1.3%	35%	148.0	(28.1)	-23.4%
CILC-1D	71.4	2.5%	69%	78.3	(6.9)	-9.7%
HLFT-1	35.8	2.9%	79%	38.0	(2.2)	-6.2%
CILC-1T	25.3	2.5%	66%	27.6	(2.4)	-9.3%
HLFT-3	24.3	1.3%	36%	29.8	(5.5)	-22.6%
GSLD(T)-2	21.7	2.4%	66%	24.1	(2.4)	-10.9%
SDTR-2	16.0	2.0%	53%	18.5	(2.6)	-16.1%
SDTR-1	16.0	3.4%	92%	16.3	(0.4)	-2.2%
All Other (7 Classes)	17.0	N/A	N/A	17.9	(1.0)	-5.7%
Total Revenues from Sales	$3,974.9	3.7%	100%	$3,974.9	$0.0	100%
Misc Service Charges	77.5			77.5		
Other Operating Revenues	122.6			122.6		
Total Operating Revenues	$4,175.0			$4,175.0		

Notes:
(1) Provided on MFR E-1, Achieved at Present Rates.
(2) Provided on MFR E-1, Equalized at Present Rates.
N/A = Not Applicable

Totals may not add due to rounding.

Target Revenue Requirements at Proposed Rates

For the Test Year 2010
($ Millions)

(1) Rate Class	(2) Achieved Revenues from Sales [1]	(3) Target Revenue Requirements [2]	(4) Revenue Requirements Deficiency (3) - (2)	(5) Percent Difference (4) / (2)
RS(T)-1	$2,315.9	$2,798.7	$482.8	20.8%
GSD(T)-1	741.5	955.7	214.2	28.9%
GS(T)-1	289.9	308.2	18.3	6.3%
GSLD(T)-1	141.7	211.5	69.8	49.3%
HLFT-2	115.4	188.7	73.3	63.5%
CILC-1D	71.4	101.7	30.4	42.6%
SL-1	68.9	82.2	13.2	19.2%
HLFT-1	34.8	47.6	12.8	36.7%
CILC-1T	25.2	35.2	10.0	39.5%
HLFT-3	23.5	38.2	14.7	62.6%
GSLD(T)-2	20.9	30.1	9.2	44.0%
SDTR-2	15.5	23.8	8.2	53.0%
SDTR-1	15.4	20.3	4.9	32.1%
All Other (12 Classes)	40.8	47.2	6.4	15.6%
Total Revenues from Sales	$3,920.9	$4,889.1	$968.2	24.7%
Misc. Service Charges	76.2	151.6	75.3	98.8%
Other Operating Revenues	117.6	117.6	0.0	0.0%
Total Operating Revenues	$4,114.7	$5,158.3	$1,043.5 [3]	25.4%

Notes:
(1) Provided on MFR E-1, Achieved at Present Rates.
(2) Provided on MFR E-1, Equalized at Proposed Rates.
(3) Per MFR A-1, 2010 Test Year, Revenue Increase Requested, Line 16.

Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 159
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Joseph A. Ender (JAE-6)
DATE 09/05/09

Target Revenue Requirements at Proposed Rates

For the Subsequent Year 2011
($ Millions)

(1) Rate Class	(2) Achieved Revenues from Sales [(1)]	(3) Target Revenue Requirements [(2)]	(4) Revenue Requirements Deficiency (3) - (2)	(5) Percent Difference (4) / (2)
RS(T)-1	$2,327.0	$2,955.2	$628.3	27.0%
GSD(T)-1	763.0	1,032.6	269.6	35.3%
GS(T)-1	298.2	333.9	35.6	11.9%
GSLD(T)-1	144.7	227.1	82.4	56.9%
HLFT-2	119.9	205.5	85.6	71.4%
CILC-1D	71.4	106.4	35.0	49.0%
SL-1	70.8	85.3	14.5	20.5%
HLFT-1	35.8	51.2	15.5	43.3%
CILC-1T	25.3	36.5	11.3	44.6%
HLFT-3	24.3	41.3	17.0	70.0%
GSLD(T)-2	21.7	32.9	11.2	51.6%
SDTR-2	16.0	25.7	9.7	60.7%
SDTR-1	16.0	22.0	6.0	37.8%
All Other (12 Classes)	40.9	49.1	8.2	20.0%
Total Revenues from Sales	$3,974.9	$5,204.8	$1,229.9	30.9%
Misc. Service Charges	77.5	153.8	76.4	98.6%
Other Operating Revenues	122.6	122.6	0.0	0.0%
Total Operating Revenues	$4,175.0	$5,481.3	$1,306.2 [(3)]	31.3%

Notes:

(1) Provided on MFR E-1, Achieved at Present Rates.
(2) Provided on MFR E-1, Equalized at Proposed Rates.
(3) Per MFR A-1, 2011 Subsequent Year, Revenue Requirement (No 2010 Rate Relief), Line 16.

Totals may not add due to rounding.

Docket No. 080677-EI
Summary of Sponsored MFRs
Exhibit RBD-1, Page 1 of 2

SUMMARY OF SPONSORED MFRS AND SCHEDULES

SPONSOR	Period	Title
A-2	2010 Test Year	Full Revenue Requirements Bill Comparison - Typical Monthly Bills
A-2	2011 Subsequent Year	Full Revenue Requirements Bill Comparison - Typical Monthly Bills
A-3	2010 Test Year	Summary of Tariffs
A-3	2011 Subsequent Year	Summary of Tariffs
C-5	2010 Test Year	Operating Revenues Detail
C-5	2011 Subsequent Year	Operating Revenues Detail
E-8	2010 Test Year	Company-Proposed Allocation of the Rate Increase by Rate Class
E-8	2011 Subsequent Year	Company-Proposed Allocation of the Rate Increase by Rate Class
E-12	2010 Test Year	Adjustment to Test Year Revenue
E-12	2011 Subsequent Year	Adjustment to Test Year Revenue
E-13a	2010 Test Year	Revenue from Sale of Electricity by Rate Schedule
E-13a	2011 Subsequent Year	Revenue from Sale of Electricity by Rate Schedule
E-13b	2010 Test Year	Revenue from Sale of Electricity by Rate Schedule - Service Charges
E-13b	2011 Subsequent Year	Revenue from Sale of Electricity by Rate Schedule - Service Charges
E-13c	2010 Test Year	Base Revenue by Rate Schedule - Calculations
E-13c	2011 Subsequent Year	Base Revenue by Rate Schedule - Calculations

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 160
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Renae B. Deaton (RBD-1)
DATE 09/05/09

SUMMARY OF SPONSORED MFRS AND SCHEDULES - CONTINUED

	Period	Title
SPONSOR		
E-13d	2010 Test Year	Revenue by Rate Schedule - Lighting Schedule Calculation
E-13d	2011 Subsequent Year	Revenue by Rate Schedule - Lighting Schedule Calculation
E-14	2010 Test Year	Proposed Tariff Sheets and Support for Charges
E-14	2011 Subsequent Year	Proposed Tariff Sheets and Support for Charges
E-15	2010 Test Year	Projected Billing Determinants
E-15	2011 Subsequent Year	Projected Billing Determinants

SUMMARY OF CO-SPONSORED MFRS AND SCHEDULES

	Period	Title
CO-SPONSOR		
E-1	2010 Test Year	Cost of Service Studies
E-1	2011 Subsequent Year	Cost of Service Studies
F-5	2010 Test Year	Forecasting Models
F-5	2011 Subsequent Year	Forecasting Models

SUMMARY OF SPONSORED 2009 SUPPLEMENTAL MFRS

	Period	Title
SPONSOR		
C-5	2009 Supplemental	Operating Revenues Detail

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080677-EI & 090130-EI EXHIBIT 161

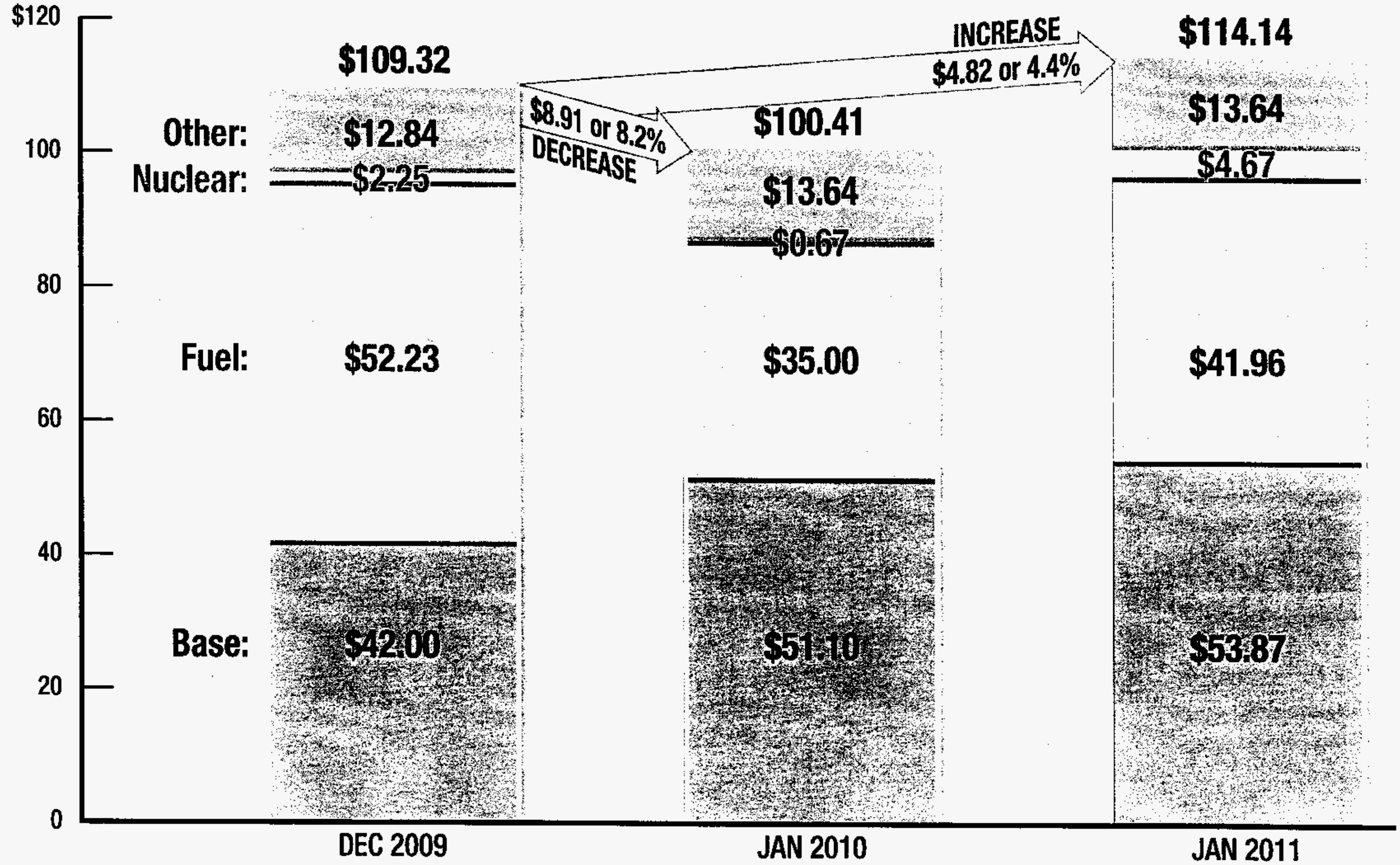
COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS Renae B. Deaton (RBD-2)

DATE 09/05/09

FPL Typical Residential 1,000 kWh Bill

Updated to reflect estimated adjustments to base reflected in KO-16, and 2010 & 2011 Fuel and Capacity Clause Projections as of August 20, 2009



Source: MFR A-2 for December 2009, the 2010 Test Year, and the 2011 Subsequent Year with updates to base, fuel, nuclear and capacity costs noted below:
2010 and 2011 Base updated to reflect adjustments per KO-16
2010 fuel, nuclear, and capacity prices based on the August 20, 2009 Fuel and Capacity Cost Recovery filing in Docket No. 090001-EI
2011 fuel, nuclear, and capacity prices based on fuel cost projections as of August 10, 2009
"Other" includes clauses other than fuel and nuclear recovery, such as energy conservation and gross receipts tax

Docket No. 080677-EI
FPL Typical Residential
1,000 kWh Bill for
December 2009, January
2010 and January 2011
Exhibit RBD-2, Page 1 of 1
Updated August 20, 2009

Change in 1,000 kWh Residential Base Bill Compared To Change in the Consumer Price Index (CPI) 1985 to Current				
	Jan. 1985	**Current (1)**	**Net Change**	**Percent Change**
FPL Residential Base Bill for 1,000 kWh	**$47.15**	**$39.31**	**($7.84)**	**-16.6%**
Consumer Price Index (CPI)	**105.5**	**210.2**	**104.7**	**99.3%**

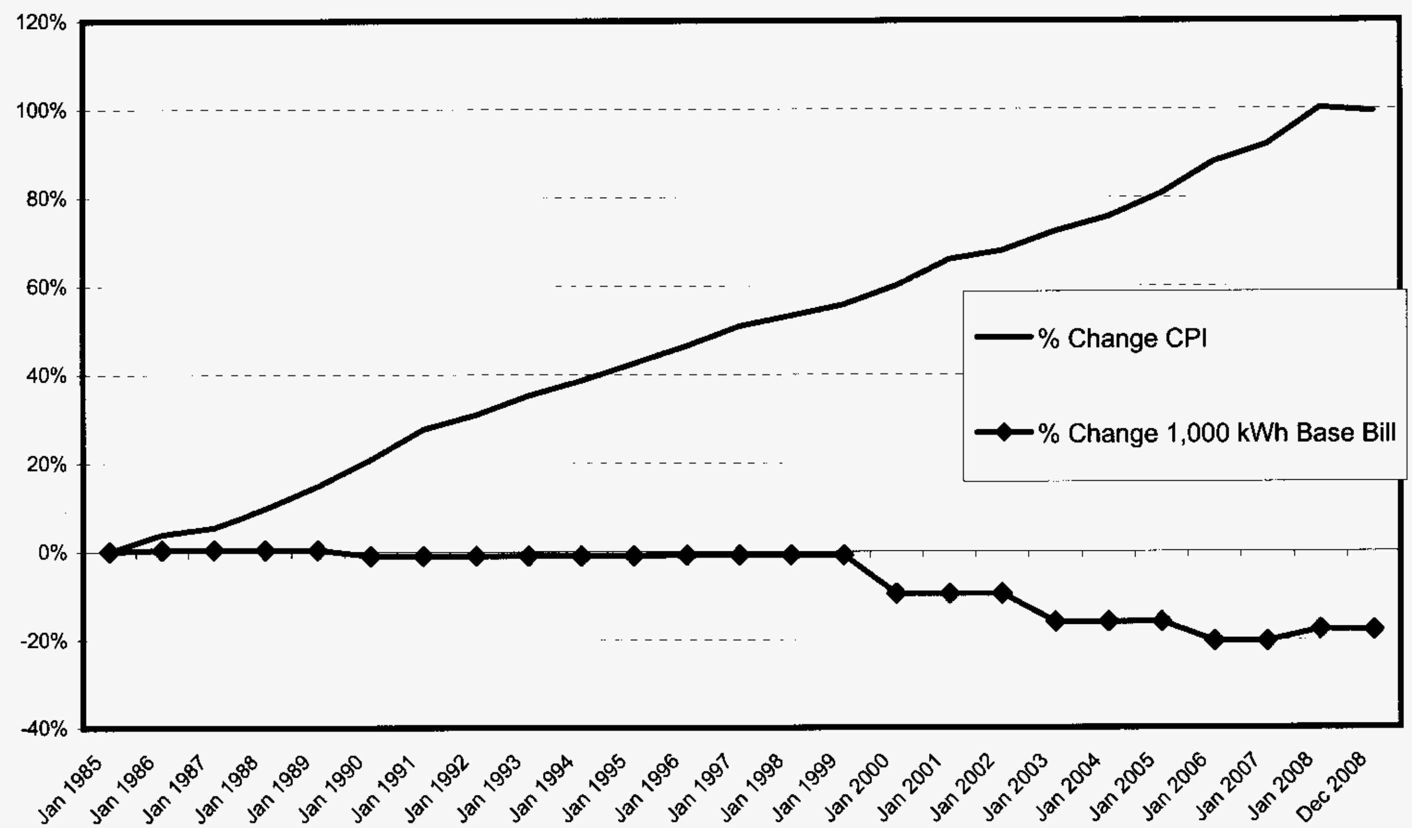
(1) Current FPL residential base bill for 1,000 kWh includes February 9, 2009 fuel price and clause estimates and current consumer price index as of December 2008

January 1985 Inflation-Adjusted 1,000 kWh Residential Typical Bill Compared To Current January 2009 Typical Bill				
	Jan. 1985 (Base bill inflation-adjusted to Dec. 2008)	**Jan. 2009**	**Net Change**	**Percent Change**
Base Bill	**$93.96**	**$39.31**	**($54.65)**	**-58.2%**
All clauses as of Jan. 2009	**67.50**	**67.50**	**0.00**	**0.0%**
Subtotal	**$161.46**	**$106.81**	**($54.65)**	**-33.8%**
Gross receipt tax	**4.14**	**2.74**	**($1.40)**	**-33.8%**
TOTAL	**$165.60**	**$109.55**	**($56.05)**	**-33.8%**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 162
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Renae B. Deaton (RBD-3)
DATE 09/05/09

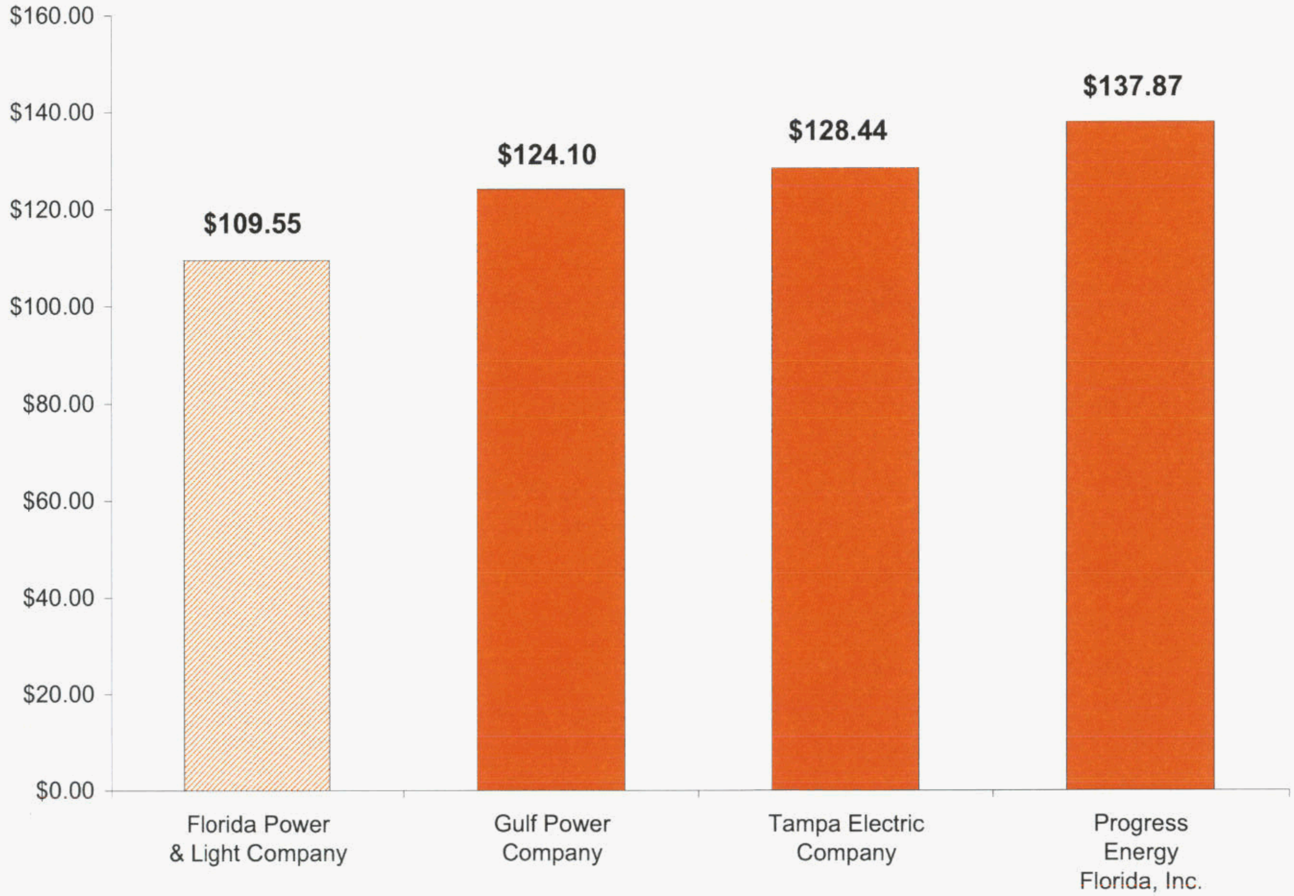
Docket No. 080677-EI
Comparison of FPL's Base
Rates Versus Change in CPI
Exhibit RBD-3, Page 2 of 2

Percent Change in CPI versus 1,000 kWh Residential Base Bill
1985 to Current



Major Florida Utility Typical Bill Comparison

Residential 1,000 kWh Monthly Bill
For rates effective January 2009



Docket No. 080677-EI
Major Florida Utility Typical
Residential Bill Comparison
Exhibit RBD-4, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 163
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Renae B. Deaton (RBD-4)
DATE 09/05/09

SUMMARY OF CURRENT RATE STRUCTURES

FOR MAJOR RATE SCHEDULES

RATE SCHEDULE	DESCRIPTION
RS-1	Residential Service
GS-1	General Service – Non Demand (0-20 kW)
GSD-1	General Service Demand (21-499 kW)
GSLD-1	General Service Large Demand (500-1,999 kW)
GSLD-2	General Service Large Demand (2,000 kW+)
GSLD-3	General Service Large Demand – Transmission (2,000 kW+)
CS-1	Curtailable Service (500-1999 kW)
CS-2	Curtailable Service (2,000 kW +)
CS-3	Curtailable Service – Transmission (2,000 kW+)
RST-1	Residential Service – Time of Use
GST-1	General Service – Non Demand – Time of Use (0-20kW)
GSDT-1	General Service Demand – Time of Use (21-499 kW)
GSLDT-1	General Service Large Demand – Time of Use (500-1,999 kW)
GSLDT-2	General Service Large Demand – Time of Use (2,000 kW+)
GSLDT-3	General Service Large Demand – Time of Use (2,000 kW+)
CST-1	Curtailable Service – Time of Use (500-1,999 kW)
CST-2	Curtailable Service – Time of Use (2,000 kW +)
CST-3	Curtailable Service – Time of Use (2,000 kW +)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 164
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Renae B. Deaton (RBD-5)
DATE 09/05/09

HLFT	High Load Factor-Time of Use
CILC-1	Commercial/Industrial Load Control Program
CDR	Commercial/Industrial Demand Reduction Rider
SDTR	Seasonal Demand-Time of Use Rider
SST-1	Standby and Supplemental Service
ISST-1	Interruptible Standby and Supplemental Service
MET	Metropolitan Transit Service
OS-2	Sports Field Service
SL-1	Street Lighting
OL-1	Outdoor Lighting
PL-1	Premium Lighting
SL-2	Traffic Signal Service
GSCU	General Service Constant Usage
WIES	Wireless Internet Electric Service

RS-1

The residential rate schedule RS-1 has a customer charge and an inverted or increasing energy charge. RS-1 customers are charged a higher cents/kWh energy charge for all kWh above 1,000.

GS-1

Rate schedule GS-1 includes an energy charge and a customer charge.

GSD-1

The rate structure for general service demand customers (GSD-1) includes demand, energy, and customer charges.

GSLD-1, GSLD-2, GSLD-3

The rate structures for general service large demand customers (GSLD-1, GSLD-2, GSLD-3) include demand, energy, and customer charges. There are separate rate schedules for customers with demands between 500 kW and 1,999 kW, for customers with demands above 2,000 kW, and for customers above 2,000 kW served directly from the transmission system.

CS-1, CS-2, CS-3

Curtailable customers are given a credit for each kW of curtailable load. The curtailable rate otherwise mirrors the rate structure of the otherwise applicable general service large demand rate schedule.

Time-of-Use (TOU)

Separate TOU rate schedules have been established for residential, general service, general service demand, general service large demand, and curtailable customers. The current TOU options for these customers generally reflect the otherwise applicable rate structures, with the addition of providing time-differentiated charges. Separate energy charges are applicable to the on-peak and off-peak periods. In addition, the demand charges are applicable only in the on-peak period. All of FPL's General Service TOU rates share the same on-peak and off-peak rating periods, as shown below.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day. April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m., excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

<u>HLFT</u>

High load factor – time of use (HLFT) rates are designed to provide a rate that is attractive to the higher load factor customers while also providing a time-differentiated price signal. There are three separate HLFT rate schedules; HLFT-1 is applicable to customers with demands between 21-499 kW, HLFT-2 is applicable to customers with demands between 500-1,999 kW, and HLFT-3 is applicable to customers with demands 2,000 kW and above. Each rate schedule includes a customer charge, an on-peak firm demand charge, a maximum demand charge, on-peak energy charge, and an off-peak energy charge.

The HLFT customers share the same on-peak and off-peak rating periods, as the General Service time of use customers, reflected above.

CILC-1

Commercial/industrial load control (CILC-1) rates are designed to provide applicable customers with lower rates in exchange for allowing the Company to interrupt the customers' load during periods of capacity constraint. The rate schedule has been closed to new customers since 1996. There are three separate CILC-1 rate schedules: CILC-1G is applicable to customers with demands between 200-499 kW, CILC-1D serves customers with demands of 500 kW and above, and CILC-1T applies to customers served directly from the transmission system. Each rate schedule includes a customer charge, an on-peak firm demand, an on-peak interruptible demand, and an energy charge. In addition, customers served from the distribution system are also charged a maximum demand based on their highest demand, regardless of time of day, over the last 24 months.

CDR Rider

Non-firm service is also offered under the Commercial/Industrial Demand Reduction (CDR) rider. Under this rider, customers are billed under their otherwise applicable tariff, but receive a credit per kW of controllable load. Also, load control equipment is installed to provide the utility with direct control over the customer's electrical load. This differs from the curtailable rate schedules where the customer would have manual control over the electrical load. These customers are also charged an adder to their customer charge to recover the cost of load control equipment.

<u>SDTR</u>

The Seasonal Demand TOU rider was designed for customers who typically experience lower usage during the summer months, and provides a time-differentiated rate with a narrower on-peak window than that specified under the standard TOU rates during the months of June through September. The on-peak period under the Seasonal Demand TOU rider is limited to 3PM-6PM weekdays (excluding holidays) in June through September. Customers under the Seasonal Demand TOU rider may elect to receive service under either a time differentiated or non-time differentiated rate during the non-seasonal period of January through May and October through December. For customers who elect a time differentiated rate during the non-seasonal period, the standard TOU rating periods would apply, as reflected above. There are three separate SDTR rate schedules; SDTR-1 is applicable to customers with demands between 21-499 kW, SDTR-2 is applicable to customers with demands between 500-1,999 kW, and SDTR-3 is applicable to customers with demands 2,000 kW and above. Each rate schedule includes a customer charge, a seasonal demand charge, a non-seasonal demand charge, seasonal energy charge, and a non-seasonal energy charge.

<u>SST-1</u>

Standby rates are applicable to customers whose electric service requirements are supplied or supplemented from the customer's generation equipment at the point of service. Consistent with the requirements found in the tariffs of the other Florida IOUs, a customer is required to take service under one of the standby rate schedules if the customer's total generation capacity is more than 20% of the customer's total electrical load and the customer's generator(s) is (are) not for emergency purposes only. The terms and conditions under FPL's standby tariffs were established in Docket No. 850673-EU. This docket, undertaken as a generic investigation of standby rates for electric utilities, outlined the rate structure appropriate for standby service, including the use of daily demand charges and reservation demand charges. As a result, FPL's standby tariff incorporates a daily demand charge based on the daily maximum on-peak demand and a reservation demand charge. Standby customers are charged the greater of the sum of the daily demand charges or the reservation demand charge times the maximum on-peak standby demand actually registered during the month, plus the reservation demand charge times the difference between the contract standby demand and the maximum on-peak standby demand actually registered during the month. These demand charges vary by rate schedule. FPL has four separate standby rate schedules: SST-1(D1) serves customers with demands below 500 kW; SST-1(D2) is applicable to customers with demands between 500 kW and 1,999 kW; SST-1(D3) applies to customers with demands of 2,000 kW and above; and SST-1(T) is utilized by customers served directly from the transmission system. In addition, standby customers served from the distribution system are charged a distribution demand charge (which also varies by rate schedule) based on their contract standby demand. Finally, each of the standby rate schedules incorporates its own set of customer and energy charges.

ISST

Interruptible standby rates are applicable to customers whose electric service requirements are supplied or supplemented from the customer's generation equipment at that point of service and receive electric service from FPL on an interruptible basis. The nature of and characteristics of interruptible standby service are the same as otherwise described above for SST except that all, or a portion, of standby and/or supplemental load has been included in an Interruptible Standby and Supplemental Service Agreement and is not served on a firm basis. FPL has two separate rate schedules for interruptible standby service: ISST-1(T) for service at transmission voltage 69kV and above; and ISST-1(D) for interruptible standby service at distribution voltage below 69kV. The ISST-1(T) and ISST-1(D) have voltage differentiated customer charges, base energy charges, as well as firm and interruptible reservation and daily demand charges. A distribution demand charge is applied to the maximum demand of ISST-1(D).

MET

Electric service to the Metropolitan Dade County Electric Transit System is provided under the MET rate schedule. The rate structure for MET includes customer, energy and demand charges. The demand charge is based on the electric transit system's group coincident peaks.

OS-2

Sports field service is provided under the OS-2 rate schedule. The rate schedule has been closed to new customers since 1982. The rate schedule includes a customer and an energy charge.

SL-1, OL-1 and PL-1

Street lighting (SL-1) and outdoor lighting (OL-1) customers are assessed a bundled monthly charge which includes fixture, maintenance, and non-fuel energy components. These monthly charges vary by wattage level, type of fixture and level of service provided. Customers owning their own lighting facilities may receive either energy only or energy and relamping service. The charges for all other SL-1 and OL-1 customers are based on the cost of Company-owned fixtures. SL-1 and OL-1 customers are also charged a flat monthly fee for any poles, down-guys or conductors dedicated to lighting service.

Where FPL installs special decorative lighting facilities at the customer's option, service is provided under the Premium Lighting (PL-1) rate schedule. Under PL-1, customers are charged based on the actual project costs incurred in installing lighting facilities. Customers may elect to pay for facilities in a lump-sum, over 10 years, or over 20 years. A Present Value Revenue Requirements (PVRR) multiplier applied to the total work order cost of the project determines the lump-sum amount. The monthly carrying charges under the 10 year and 20 year payment options are derived from the PVRR multiplier applied to the total work order cost and levelized over the appropriate payment period.

SL-2

Unmetered service to traffic signal systems is provided under the SL-2 rate schedule. The rate schedule includes an energy charge.

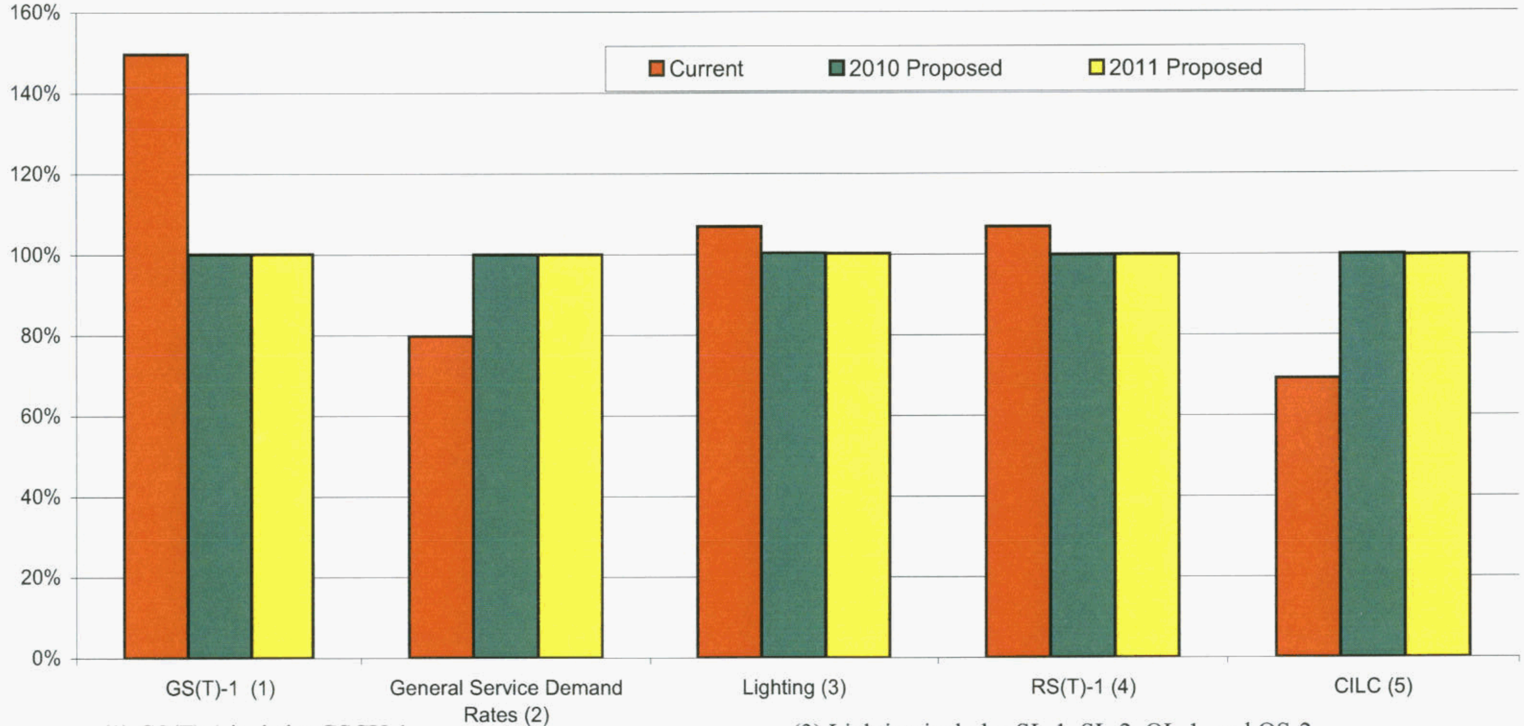
GSCU

Unmetered service to General Service customers with a constant usage is provided under the GSCU rate schedule. The rate schedule includes an energy charge.

WIES

Unmetered service to General Service customers for wireless internet devices is provided under the WIES rate schedule. The rate schedule includes an energy charge.

Parity of Major Rate Classes
Current and Proposed



(1) GS(T)-1 includes GSCU-1

(2) GSD(T)-1, GSLD(T)-1, GSLD(T)-2, GSLD(T)-3, CS(T), HLFT 1, 2, & 3, and SDTR 1, 2 & 3

(3) Lighting includes SL-1, SL-2, OL-1, and OS-2

(4) RS-1 and RST-1 combined clases

(5) All combined CILC classes

Docket No. 080677-EI
Resulting Parity Indices
Exhibit RBD-6, Page 1 of 2

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 165
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Renae B. Deaton (RBD-6)
DATE 09/05/09

Resulting Parity Indices

	2010 FPL Present	2010 FPL Proposed Parity	2011 FPL Proposed Parity
CILC-1D	67%	100%	100%
CILC-1G	121%	100%	100%
CILC-1T	64%	100%	100%
CS(T)-1	91%	128%	128%
CS(T)-2	90%	119%	120%
GS(T)-1	150%	100%	100%
GSCU-1	181%	114%	100%
GSD(T)-1	96%	103%	103%
GSLD(T)-1	58%	101%	101%
GSLD(T)-2	66%	101%	100%
GSLD(T)-3	85%	104%	106%
HLFT-1	79%	82%	78%
HLFT-2	34%	90%	91%
HLFT-3	35%	84%	79%
MET	88%	100%	100%
OL-1	159%	100%	100%
OS-2	47%	100%	100%
RS(T)-1	107%	100%	100%
SDTR-1	90%	107%	109%
SDTR-2	53%	98%	97%
SDTR-3	32%	73%	74%
SL-1	102%	100%	100%
SL-2	225%	128%	117%
SST-DST	74%	100%	100%
SST-TST	370%	205%	199%
Total	100%	100%	100%
Number of classes within +/ 10% of parity	5	16	18

SUMMARY OF PROPOSED RATE STRUCTURES

FOR MAJOR RATE SCHEDULES

RATE SCHEDULE	DESCRIPTION
RS-1	Residential Service
GS-1	General Service – Non Demand (0-20 kW)
GSD-1	General Service Demand (21-499 kW)
GSLD-1	General Service Large Demand (500-1,999 kW)
GSLD-2	General Service Large Demand (2,000 kW+)
GSLD-3	General Service Large Demand – Transmission (2,000 kW+)
CS-1	Curtailable Service (500-1999 kW)
CS-2	Curtailable Service (2,000 kW +)
CS-3	Curtailable Service – Transmission (2,000 kW+)
RST-1	Residential Service – Time of Use
GST-1	General Service – Non Demand – Time of Use (0-20kW)
GSDT-1	General Service Demand – Time of Use (21-499 kW)
GSLDT-1	General Service Large Demand – Time of Use (500-1,999 kW)
GSLDT-2	General Service Large Demand – Time of Use (2,000 kW+)
GSLDT-3	General Service Large Demand – Time of Use (2,000 kW+)
CST-1	Curtailable Service – Time of Use (500-1,999 kW)
CST-2	Curtailable Service – Time of Use (2,000 kW +)
CST-3	Curtailable Service – Time of Use (2,000 kW +)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 166
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Renae B. Deaton (RBD-7)
DATE 09/05/09

HLFT	High Load Factor-Time of Use
CILC-1	Commercial/Industrial Load Control Program
CDR	Commercial/Industrial Demand Reduction Rider
SDTR	Seasonal Demand-Time of Use Rider
SST-1	Standby and Supplemental Service
ISST-1	Interruptible Standby and Supplemental Service
MET	Metropolitan Transit Service
OS-2	Sports Field Service
SL-1	Street Lighting
OL-1	Outdoor Lighting
PL-1	Premium Lighting
SL-2	Traffic Signal Service
GSCU	General Service Constant Usage
WIES	Wireless Internet Electric Service

RS-1

A customer charge of \$5.90 is derived from the customer unit cost presented in MFR E-6b. The RS-1 rate has an inversion point of 1,000 kWh that was established in January 2006 based on Commission approval in Docket No.050045-EI. FPL proposes an energy charge of 4.581 cents/kWh for the first 1000 kWh and an energy charge of 5.581 cents/kWh for all additional kWh.

RST-1

FPL is proposing a customer charge of $16.06 to reflect the additional cost of time-of-use metering. The on-peak energy charge was initially set based on the demand and energy unit costs provided in MFR E-6b. The off-peak energy charge was initially set based on the energy unit costs provided in MFR E-6b. Proportionate adjustments were made to both energy charges in order to provide for revenue neutrality with the otherwise applicable RS-1 rate schedule.

GS-1

The proposed customer charge of $7.07 is derived from the customer unit costs provided in MFR E-6b. The proposed discount for unmetered service is based on the meter-related expenses included in the customer unit costs. An energy charge of 4.674 cents/kWh is proposed based on the rate class's target revenues.

GST-1

FPL is proposing a customer charge of $13.89 to reflect the additional cost of time-of-use metering. The on-peak energy charge was initially set based on the demand and energy unit costs provided in MFR E-6b. The off-peak energy charge was initially set based on the energy unit costs provided in MFR E-6b. Proportionate adjustments were made to both energy charges in order to provide for revenue neutrality with the otherwise applicable GS-1.

General Service Demand Rate Schedules

The general service (GS) demand rate schedules (including GLSD-3) are treated as a group for purposes of rate development to better allow for the appropriate relationships between rate levels while striving to achieve parity, both for the group and the individual rate classes. The HLFT and SDTR rates are a function of the GS demand rates and as a result they are incorporated into this group as well. As the curtailable service (CS) rates are a function of the GSLD rates, the target revenues for CS are also incorporated.

First, the customer charge for each rate is updated with the appropriate customer unit cost. Next, unit demand and energy costs for the group are determined and initial adjustments are made to help meet target revenues and achieve revenue neutrality for the corresponding TOU rates. Adjustments are made to the GLSD-3 demand charges to account for the fact that GSLD-3 customers do not incur distribution costs. Once the initial adjustments are complete, the energy rate is adjusted for all included classes for revenue balancing. No changes are proposed for the curtailable credits available under the curtailable rate schedules. The proposed rates are as outlined below.

GSD-1, GLSD-1, GSLD-2, and GLSD-3

	GSD-1	GSLD-1	GSLD-2	GSLD-3
Customer	\$18.30	\$60.46	\$221.27	\$1,891.81
Demand	\$8.70	\$10.45	\$10.45	\$7.95
Energy	1.634 ¢	1.506¢	1.337¢	0.783 ¢

CS-1, CS-2, and CS-3

	CS-1	CS-2	CS-3
Customer	$60.46	$221.27	$1,891.81
Demand	$10.45	$10.45	$7.95
Energy	1.506 ¢	1.337¢	0.783 ¢

GSDT-1, GLSDT-1, GSLDT-2, and GLSDT-3

	GSDT-1	GSLDT-1	GSLDT-2	GSLDT-3
Customer	$25.34	$60.46	$221.27	$1,891.81
Demand	$8.70	$10.45	$10.45	$7.95
On-Peak Energy	2.621 ¢	2.488 ¢	2.371 ¢	1.821 ¢
Off-Peak Energy	1.205 ¢	1.072 ¢	0.954 ¢	0.405 ¢

CST-1, CST-2, and CST-3

	CST-1	CST-2	CST-3
Customer	$60.46	$221.27	$1,891.81
Demand	$10.45	$10.45	$7.95
On-Peak Energy	2.488 ¢	2.371¢	1.821 ¢
Off-Peak Energy	1.072 ¢	0.954¢	0.405 ¢

HLFT-1, HLF-2, and HLFT-3

	HLFT-1	HLFT-2	HLFT-3
Customer	$25.34	$60.46	$221.27
On-Peak Demand	$9.77	$9.77	$9.77
Demand (Max)	$2.20	$2.20	$2.20
On-Peak Energy	1.772 ¢	2.300 ¢	2.080 ¢
Off-Peak Energy	0.715 ¢	0.794 ¢	0.743 ¢

SDTR-1, SDTR-2, and SDTR-3 Option A

	SDTR-1	SDTR-2	SDTR-3
Customer	$25.34	$60.46	$221.27
Seasonal On Peak Energy	6.631 ¢	6.028 ¢	4.665 ¢
Seasonal Off-Peak Energy	1.125¢	1.037¢	0.921¢
Non-Seasonal Energy	1.634¢	1.506¢	1.337¢
Seasonal On-Peak Demand	$10.31	$12.38	$12.38
Non-Seasonal Demand	$8.23	$9.76	$9.93

SDTR-1, SDTR-2, and SDTR-3 Option B

	SDTR-1	SDTR-2	SDTR-3
Customer	$25.34	$60.46	$221.27
Seasonal On-Peak Energy	6.631¢	6.028¢	4.665¢
Seasonal Off-Peak Energy	1.125¢	1.037¢	0.921¢
Non-Seasonal On-Peak Energy	3.673 ¢	3.110 ¢	2.718 ¢
Non-Seasonal Off-Peak Energy	1.125 ¢	1.037 ¢	0.921 ¢
Seasonal On-Peak Demand	$10.31	$12.38	$12.38
Non-Seasonal Demand	$8.23	$9.76	$9.93

CILC-1

The customer charges for CILC-1G, CILC-1D, and CILC-1T of $144.00, $209.00, and $2,510.00, respectively are being proposed based on the customer unit costs in MFR E-6b. The load control on-peak kW charge for CILC-1G, CILC-1D, and CILC-1T of $1.71, $1.78, and $1.70, respectively, are based on the classes' average transmission demand unit cost. The firm on-peak kW charge for CILC-1G, CILC-1D, and CILC-1T of $8.70, $9.04, and $8.61, respectively are based on the classes' average production and transmission demand unit cost. The maximum kW charge for CILC-1G and CILC-1D, of $3.88 and $3.88, respectively are based on the distribution demand revenue requirements divided by the sum of the maximum kW demands. The proposed energy charges are based on each rate classes' energy unit cost presented in MFR E-6b with adjustments to achieve the target revenues by rate class.

CDR Rider

No changes are proposed for the credits available under the CDR rider. The revisions to the administrative adders are proposed based on the customer unit costs reported in MFR E-6b. Specifically, the proposed administrative adder by rate schedule is based on the difference between the customer unit costs under the applicable CILC rate schedule and that of the otherwise applicable tariff.

SST-D1, SST-D2, and SST-D3

The proposed charges for the SST-D1, SST-D2, and SST-D3 rate schedules are based on the rate design originally approved by the Commission in Order No. 17159 in Docket No. 850673-EU ("Standby Order"). Consistent with the Standby Order, the reservation demand charge is based on an assumed 10% outage rate and the total system production and transmission demand revenue requirements divided by the system 12 CP adjusted for losses. The daily demand charge is based on the total system production and transmission demand revenue requirements divided by the system 12 CP adjusted for losses and divided by the number of on-peak days in an average month in 2010. The maximum demand charge is based on the otherwise applicable rate class's demand distribution revenue requirements divided by the class maximum billing kW with adjustments to achieve the target revenues by rate class. The energy charge is based on the system average unit energy costs adjusted for losses. The customer charge reflects the curtailable service rate schedule plus an additional $25 as an administrative adder.

SST-1T

The design of the SST-1T rate follows from the Standby Order while also considering the load characteristics of this rate class. The reservation demand charge is based on an outage rate consistent with the class's earned return and the class's production and transmission demand revenue requirements divided its 12 CP contribution. The daily demand charge is based on the class's production and transmission demand revenue requirements divided by its 12 CP contribution and divided by the number of on-peak days in an average month in 2010. The proposed energy charge is based on the rate class's energy unit cost. The customer charge is based on the customer unit cost in MFR E-6b.

ISST-1

FPL did not forecast any customers under ISST-1 for the 2010 Test Year. However, in the interests of maintaining these rates for future customers, FPL proposes firm and interruptible customer, demand, and energy charges under ISST-1 based on the applicable distribution or transmission levels of CILC or SST. The customer charges are based on CILC-1(D) and CILC-1(T) plus a

$25 administrative adder. The distribution demand charge is from CILC-1(D). The firm standby reservation and daily demand charges are based on SST-1(D3) and SST-1(T). The interruptible reservation and daily demand charges are based on the transmission-only revenue requirements from SST-1(D3) or SST-1(T). The energy charges are from SST-1(D3) and SST-1(T).

MET

The proposed customer charge of $439.81 is based on the rate class's customer unit cost in MFR E-6b. The demand charge of $11.58 /kW is based on the rate class's demand unit cost. The energy charge was initially set at the class's unit cost. Proportional adjustments were then made to the energy charge in order to achieve the target level of revenues.

OS-2

The proposed customer charge of $111.16 is based on the rate class's customer unit cost in MFR E-6b. The energy charge was initially set at the class's unit cost. Proportional adjustments were then made to the energy charge in order to achieve the target level of revenues.

SL-1, OL-1 and PL-1

Pole and conductor charges for SL-1 have been increased by an average of 48.4% and 39.6% respectively in order to more accurately reflect the costs of these facilities. Maintenance charges have also been revised based on current costs. The non-fuel energy charge is based on the unit costs reported in MFR

E-6b. Additionally, FPL is proposing to close the re-lamping option for new street lighting service installations.

Pole and conductor charges under OL-1 have been increased by an average of 22.4% and 22.4% respectively based on the cost of these facilities. The down-guy charge has likewise been increased 22.5%. Maintenance charges have also been revised based on current costs. The non-fuel energy charge is based on the unit costs reported in MFR E-6b. Adjustment to the fixture charges have also been made consistent with the rate class's target revenues. Additionally, FPL is proposing to close the re-lamping option for new outdoor lighting service installations.

For PL-1, the Present Value Revenue Requirement (PVRR) multiplier has been updated to 1.3722 for current economic assumptions, including the requested return on equity. FPL is proposing to terminate the optional (10) ten and (20) twenty years monthly rate options. Equivalent revisions have been made to the monthly facilities charges and early termination factors. The non-fuel energy charge is based on the unit costs reported in MFR E-6b for SL-1.

<u>SL-2</u>

The energy charge for SL-2 is designed to achieve the target revenues for that rate class.

<u>GSCU</u>

The energy charge for GSCU is designed to achieve the target revenues for that rate class.

<u>WIES</u>

The energy charge for WEIS is designed to achieve the target revenues for that rate class. Additionally, FPL is proposing to close this rate to new customers. FPL only had 18,240 kilowatt hours of load in 2008 on the WIES rate.

Comparison of GBRA Revenue Requirements and Fuel Cost Savings

	In-Service Dates	Jurisdictional Fuel Savings ($000)	Jurisdictional Revenue Requirement ($000)	Difference	Total Capital Expenditures ($ millions)
TP5	Jun-07	(134,780)	121,310	(13,470)	
WC1	Jun-09	(148,275)	138,519	(9,756)	688.6
WC2	Nov-09	(102,455)	127,099	24,643	632.4
WC3	Jun-11	(98,172)	181,930	83,758	864.7
Total		(483,681)	568,857	85,176	

West County Units 1, 2, and 3 fuel savings are estimated based on fuel prices as of November 6, 2008.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 167
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Renae B. Deaton (RBD-8)
DATE 09/05/09

John J. Reed
Chairman and Chief Executive Officer

John J. Reed is a financial and economic consultant with more than 30 years of experience in the energy industry. Mr. Reed has also been the CEO of an NASD member securities firm, and Co-CEO of the nation's largest publicly traded management consulting firm (NYSE: NCI). He has provided advisory services in the areas of mergers and acquisitions, asset divestitures and purchases, strategic planning, project finance, corporate valuation, energy market analysis, rate and regulatory matters and energy contract negotiations to clients across North and Central America. Mr. Reed's comprehensive experience includes the development and implementation of nuclear, fossil, and hydroelectric generation divestiture programs with an aggregate valuation in excess of $20 billion. Mr. Reed has also provided expert testimony on financial and economic matters on more than 150 occasions before the FERC, Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. After graduation from the Wharton School of the University of Pennsylvania, Mr. Reed joined Southern California Gas Company, where he worked in the regulatory and financial groups, leaving the firm as Chief Economist in 1981. He served as executive and consultant with Stone & Webster Management Consulting and R.J. Rudden Associates prior to forming REED Consulting Group (RCG) in 1988. RCG was acquired by Navigant Consulting in 1997, where Mr. Reed served as an executive until leaving Navigant to join Concentric as Chairman and Chief Executive Officer.

REPRESENTATIVE PROJECT EXPERIENCE

EXECUTIVE MANAGEMENT

As an executive-level consultant, worked with CEOs, CFOs, other senior officers, and Boards of Directors of many of North America's top electric and gas utilities, as well as with senior political leaders of the U.S. and Canada on numerous engagements over the past 25 years. Directed merger, acquisition, divestiture, and project development engagements for utilities, pipelines and electric generation companies, repositioned several electric and gas utilities as pure distributors through a series of regulatory, financial, and legislative initiatives, and helped to develop and execute several "roll-up" or market aggregation strategies for companies seeking to achieve substantial scale in energy distribution, generation, transmission, and marketing.

FINANCIAL AND ECONOMIC ADVISORY SERVICES

Retained by many of the nation's leading energy companies and financial institutions for services relating to the purchase, sale or development of new enterprises. These projects included major new gas pipeline projects, gas storage projects, several non-utility generation projects, the purchase and sale of project development and gas marketing firms, and utility acquisitions. Specific services provided include the development of corporate expansion plans, review of acquisition candidates, establishment of divestiture standards, due diligence on acquisitions or financing, market entry or expansion studies, competitive assessments, project financing studies, and negotiations relating to these transactions.

LITIGATION SUPPORT AND EXPERT TESTIMONY

Provided expert testimony on more than 150 occasions in administrative and civil proceedings on a wide range of energy and economic issues. Clients in these matters have included gas distribution utilities, gas pipelines, gas producers, oil producers, electric utilities, large energy consumers, governmental and regulatory agencies, trade associations, independent energy project developers, engineering firms, and gas and power marketers. Testimony has focused on issues ranging from broad regulatory and economic policy to virtually all elements of the utility ratemaking process. Also frequently testified regarding energy contract interpretation, accepted energy industry practices, horizontal and vertical market power, quantification of damages, and management prudence. Have been active in regulatory contract and litigation matters on virtually all interstate pipeline systems serving the U.S. Northeast, Mid-Atlantic, Midwest, and Pacific regions.

Also served on FERC Commissioner Terzic's Task Force on Competition, which conducted an industry-wide investigation into the levels of and means of encouraging competition in U.S. natural gas markets. Represented the interests of the gas distributors (the AGD and UDC) and participated actively in developing and presenting position papers on behalf of the LDC community.

RESOURCE PROCUREMENT, CONTRACTING AND ANALYSIS

On behalf of gas distributors, gas pipelines, gas producers, electric utilities, and independent energy project developers, personally managed or participated in the negotiation, drafting, and regulatory support of hundreds of energy contracts, including the largest gas contracts in North America, electric contracts representing billions of dollars, pipeline and storage contracts, and facility leases.

These efforts have resulted in bringing large new energy projects to market across North America, the creation of hundreds of millions of dollars in savings through contract renegotiation, and the regulatory approval of a number of highly contested energy contracts.

STRATEGIC PLANNING AND UTILITY RESTRUCTURING

Acted as a leading participant in the restructuring of the natural gas and electric utility industries over the past fifteen years, as an adviser to local distribution companies (LDCs), pipelines, electric utilities, and independent energy project developers. In the recent past, provided services to many of the top 50 utilities and energy marketers across North America. Managed projects that frequently included the redevelopment of strategic plans, corporate reorganizations, the development of multi-year regulatory and legislative agendas, merger, acquisition and divestiture strategies, and the development of market entry strategies. Developed and supported merchant function exit strategies, marketing affiliate strategies, and detailed plans for the functional business units of many of North America's leading utilities.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Chairman and Chief Executive Officer

CE Capital Advisors (2004 – Present)

Chairman, President, and Chief Executive Officer

Navigant Consulting, Inc. (1997 – 2002)
President, Navigant Energy Capital (2000 – 2002)

Executive Director (2000 – 2002)

Co-Chief Executive Officer, Vice Chairman (1999 – 2000)

Executive Managing Director (1998 – 1999)

President, REED Consulting Group, Inc. (1997 – 1998)

REED Consulting Group (1988 – 1997)
Chairman, President and Chief Executive Officer

R.J. Rudden Associates, Inc. (1983 – 1988)
Vice President

Stone & Webster Management Consultants, Inc. (1981 – 1983)
Senior Consultant

Consultant

Southern California Gas Company (1976 – 1981)
Corporate Economist

Financial Analyst

Treasury Analyst

Education and Certification

B.S., Economics and Finance, Wharton School, University of Pennsylvania, 1976

Licensed Securities Professional: NASD Series 7, 63, and 24 Licenses

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Boards of Directors (Past and Present)

Concentric Energy Advisors, Inc.

Navigant Consulting, Inc.

Navigant Energy Capital

Nukem, Inc.

New England Gas Association

R. J. Rudden Associates

REED Consulting Group

AFFILIATIONS

National Association of Business Economists

International Association of Energy Economists

American Gas Association

New England Gas Association

Society of Gas Lighters

Guild of Gas Managers

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080677-EI & 090130-EI EXHIBIT 169

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS John J. Reed (JJR-2)

DATE 09/05/09

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Alaska Public Utilities Commission				
Chugach Electric	12/86	Chugach Electric	Docket No. U-86-11	Cost Allocation
Chugach Electric	6/87	Enstar Natural Gas Company	Docket No. U-87-2	Tariff Design
Chugach Electric	12/87	Enstar Natural Gas Company	Docket No. U-87-42	Gas Transportation
Chugach Electric	2/88	Chugach Electric	Docket No. U-87-35	Cost of Capital
California Energy Commission				
Southern California Gas Co.	8/80	Southern California Gas Co.	Docket No. 80-BR-3	Gas Price Forecasting
California Public Utility Commission				
Southern California Gas Co.	3/80	Southern California Gas Co.	TY 1981 G.R.C.	Cost of Service, Inflation
Pacific Gas Transmission Co.	10/91	Pacific Gas & Electric Co.	App. 89-04-033	Rate Design
Pacific Gas Transmission Co.	7/92	Southern California Gas Co.	A. 92-04-031	Rate Design
Colorado Public Utilities Commission				
AMAX Molybdenum	2/90	Commission Rulemaking	Docket No. 89R-702G	Gas Transportation
AMAX Molybdenum	11/90	Commission Rulemaking	Docket No. 90R-508G	Gas Transportation
Xcel Energy	8/04	Xcel Energy	Docket No. 031-134E	Cost of Debt
CT Dept. of Public Utilities Control				
Connecticut Natural Gas	12/88	Connecticut Natural Gas	Docket No. 88-08-15	Gas Purchasing Practices
United Illuminating	3/99	United Illuminating	Docket No. 99-03-04	Nuclear Plant Valuation
Southern Connecticut Gas	2/04	Southern Connecticut Gas	Docket No. 00-12-08	Gas Purchasing Practices
Southern Connecticut Gas	4/05	Southern Connecticut Gas	Docket No. 05-03-17	LNG/Trunkline
Southern Connecticut Gas	5/06	Southern Connecticut Gas	Docket No. 05-03-17PH01	LNG/Trunkline
Southern Connecticut Gas	8/08	Southern Connecticut Gas	Docket No. 06-05-04	Peaking Service Agreement
District Of Columbia PSC				
Potomac Electric Power Company	3/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Direct)
Potomac Electric Power Company	5/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Supplemental Direct)
Potomac Electric Power Company	7/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts (Rebuttal)
Fed'l Energy Regulatory Commission				
Safe Harbor Water Power Corp.	8/82	Safe Harbor Water Power Corp.		Wholesale Electric Rate Increase
Western Gas Interstate Company	5/84	Western Gas Interstate Company	Docket No. RP84-77	Load Fcst. Working Capital
Southern Union Gas	4/87	El Paso Natural Gas Company	Docket No. RP87-16-000	Take-or-Pay Costs
Connecticut Natural Gas	11/87	Penn-York Energy Corporation	Docket No. RP87-78-000	Cost Alloc./Rate Design
AMAX Magnesium	12/88	Questar Pipeline Company	Docket No. RP88-93-000	Cost Alloc./Rate Design
Western Gas Interstate Company	6/89	Western Gas Interstate Company	Docket No. RP89-179-000	Cost Alloc./Rate Design, Open-Access Transportation
Associated CD Customers	12/89	CNG Transmission	Docket No. RP88-211-000	Cost Alloc./Rate Design

Sponsor	Date	Case/Applicant	Docket No.	Subject
Utah Industrial Group	9/90	Questar Pipeline Company	Docket No. RP88-93-000, Phase II	Cost Alloc./Rate Design
Iroquois Gas Trans. System	8/90	Iroquois Gas Transmission System	Docket No. CP89-634-000/001; CP89-815-000	Gas Markets, Rate Design, Cost of Capital, Capital Structure
Boston Edison Company	1/91	Boston Edison Company	Docket No. ER91-243-000	Electric Generation Markets
Cincinnati Gas and Electric Co., Union Light, Heat and Power Company, Lawrenceburg Gas Company	7/91	Texas Gas Transmission Corp.	Docket No. RP90-104-000, RP88-115-000, RP90-192-000	Cost Alloc./Rate Design Comparability of Svc.
Ocean State Power II	7/91	Ocean State Power II	ER89-563-000	Competitive Market Analysis, Self-dealing
Brooklyn Union/PSE&G	7/91	Texas Eastern	RP88-67, et al	Market Power, Comparability of Service
Northern Distributor Group	9/92	Northern Natural Gas Company	RP92-1-000, et al	Cost of Service
Canadian Association of Petroleum Producers and Alberta Pet. Marketing Comm.	10/92	Lakehead Pipe Line Co. L.P.	IS92-27-000	Rate Case Analysis Cost of Service
Colonial Gas, Providence Gas	7/93	Algonquin Gas Transmission	RP93-14	Cost Allocation, Rate Design
Colonial Gas, Providence Gas	8/93	Algonquin Gas Transmission	RP93-14 – Rebuttal	Cost Allocation, Rate Design
Iroquois Gas Transmission	94	Iroquois Gas Transmission	RP94-72-000	Cost of Service and Rate Design
Transco Customer Group	1/94	Transcontinental Gas Pipeline Corporation	Docket No. RP92-137-000	Rate Design, Firm to Wellhead
Pacific Gas Transmission	2/94	Pacific Gas Transmission	Docket No. RP94-149-000	Rolled-In vs. Incremental Rates
Tennessee GSR Group	1/95	Tennessee Gas Pipeline Company	Docket Nos. RP93-151-000, RP94-39-000, RP94-197-000, RP94-309-000	GSR Costs
Pacific Gas Transmission	2/95	Pacific Gas Transmission	RP94-149-000	Rate Design
Tennessee GSR Customer Group	3/95	Tennessee Gas Pipeline Company	Docket Nos. RP93-151-000, RP94-39-000, RP94-197-000, RP94-309-000	GSR Costs
ProGas and Texas Eastern	1/96	Tennessee Gas Pipeline Company	RP93-151	Declaration
PG&E and SoCal Gas	96	El Paso Natural Gas Company	RP92-18-000	Stranded Costs
Iroquois Gas Transmission System, L.P.	97	Iroquois Gas Transmission System, L.P.	RP97-126-000	Cost of Service, Rate Design
BEC Energy - Commonwealth Energy System	2/99	Boston Edison Company/ Commonwealth Energy System	EC99-___-000	Market Power Analysis – Merger
Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	10/00	Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	Docket No. EC00-___	Market Power 203/205 Filing
Wyckoff Gas Storage	12/02	Wyckoff Gas Storage	CP03-33-000	Need for Storage Project
Indicated Shippers/Producers	10/03	Northern Natural Gas	Docket No. RP98-39-029	Ad Valorem Tax Treatment
Maritimes & Northeast Pipeline	6/04	Maritimes & Northeast Pipeline	Docket No. RP04-360-000	Rolled-In Rates
ISO New England	8/04	ISO New England	Docket No. ER03-563-030	Cost of New Entry
Transwestern Pipeline Company, LLC	9/06	Transwestern Pipeline Company, LLC	Docket No. RP06-614-000	
Portland Natural Gas Transmission System	6/08	Portland Natural Gas Transmission System	Docket No. RP08-306-000	Market Assessment, natural gas transportation; rate setting

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Florida Public Service Commission				
Florida Power and Light Co.	10/07	Florida Power & Light Co.	Docket No. 07____-EI	Need for new nuclear plant
Florida Power and Light Co.	5/08	Florida Power & Light Co.	Docket No. 080009-EI	New Nuclear cost recovery
Hawaii Public Utility Commission				
Hawaiian Electric Light Company, Inc. (HELCO)	6/00	Hawaiian Electric Light Company, Inc.	Cause No. 41746	Standby Charge
Indiana Utility Regulatory Commission				
Northern Indiana Public Service Company	10/01	Northern Indiana Public Service Company	Docket No. 99-0207	Direct Testimony, Valuation of Electric Generating Facilities
Northern Indiana Public Service Company	01/08	Northern Indiana Public Service Company	Cause No. 43396	Asset Valuation
Northern Indiana Public Service Company	08/08	Northern Indiana Public Service Company	Cause No. 43526	Fair Market Value Assessment
Iowa Utilities Board				
Interstate Power and Light	7/05	Interstate Power and Light and FPL Energy Duane Arnold, LLC	Docket No. SPU-05-15	Sale of Nuclear Plant
Interstate Power and Light	5/07	City of Everly, Iowa	Docket No. SPU-06-5	Public Benefits
Interstate Power and Light	5/07	City of Kalona, Iowa	Docket No. SPU-06-6	Public Benefits
Interstate Power and Light	5/07	City of Wellman, Iowa	Docket No. SPU-06-10	Public Benefits
Interstate Power and Light	5/07	City of Terril, Iowa	Docket No. SPU-06-8	Public Benefits
Interstate Power and Light	5/07	City of Rolfe, Iowa	Docket No. SPU-06-7	Public Benefits
Maine Public Utility Commission				
Northern Utilities	5/96	Granite State and PNGTS	Docket No. 95-480, 95-481	Transportation Service and PBR
Maryland Public Service Commission				
Eastalco Aluminum	3/82	Potomac Edison	Docket No. 7604	Cost Allocation
Potomac Electric Power Company	8/99	Potomac Electric Power Company	Docket No. 8796	Stranded Cost & Price Protection (Direct)
Mass. Department of Public Utilities				
Haverhill Gas	5/82	Haverhill Gas	Docket No. DPU #1115	Cost of Capital
New England Energy Group	1/87	Commission Investigation		Gas Transportation Rates
Energy Consortium of Mass.	9/87	Commonwealth Gas Company	Docket No. DPU-87-122	Cost Alloc./Rate Design
Mass. Institute of Technology	12/88	Middleton Municipal Light	DPU #88-91	Cost Alloc./Rate Design
Energy consortium of Mass.	3/89	Boston Gas	DPU #88-67	Rate Design
PG&E Bechtel Generating Co./ Constellation Holdings	10/91	Commission Investigation	DPU #91-131	Valuation of Environmental Externalities
Coalition of Non-Utility Generators		Cambridge Electric Light Co. & Commonwealth Electric Co.	DPU 91-234 EFSC 91-4	Review Integrated Resource Management Filing
The Berkshire Gas Company Essex County Gas Company Fitchburg Gas and Elec. Light Co.	5/92	The Berkshire Gas Company Essex County Gas Company Fitchburg Gas & Elec. Light Co.	DPU #92-154	Gas Purchase Contract Approval

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Boston Edison Company	7/92	Boston Edison	DPU #92-130	Least Cost Planning
Boston Edison Company	7/92	The Williams/Newcorp Generating Co.	DPU #92-146	RFP Evaluation
Boston Edison Company	7/92	West Lynn Cogeneration	DPU #92-142	RFP Evaluation
Boston Edison Company	7/92	L'Energia Corp.	DPU #92-167	RFP Evaluation
Boston Edison Company	7/92	DLS Energy, Inc.	DPU #92-153	RFP Evaluation
Boston Edison Company	7/92	CMS Generation Co.	DPU #92-166	RFP Evaluation
Boston Edison Company	7/92	Concord Energy	DPU #92-144	RFP Evaluation
The Berkshire Gas Company Colonial Gas Company Essex County Gas Company Fitchburg Gas and Electric Company	11/93	The Berkshire Gas Company Colonial Gas Company Essex County Gas Company Fitchburg Gas and Electric Co.	DPU #93-187	Gas Purchase Contract Approval
Bay State Gas Company	10/93	Bay State Gas Company	Docket No. 93-129	Integrated Resource Planning
Boston Edison Company	94	Boston Edison	DPU #94-49	Surplus Capacity
Hudson Light & Power Department	4/95	Hudson Light & Power Dept.	DPU #94-176	Stranded Costs – Direct
Essex County Gas Company	5/96	Essex County Gas Company	Docket No. 96-70	Unbundled Rates
Boston Edison Company	8/97	Boston Edison Company	D.P.U. No. 97-63	Holding Company Corporate Structure
Berkshire Gas Company	6/98	Berkshire Gas Mergeco Gas Co.	D.T.E. 98-87	Regulatory Issues
Eastern Edison Company	8/98	Montaup Electric Company	D.T.E. 98-83	Marketing for divestiture of its generation business.
Boston Edison Company	98	Boston Edison Company	D.T.E. 97-113	Fossil Generation Divestiture
Boston Edison Company	98	Boston Edison Company	D.T.E. 98-119	Nuclear Generation Divestiture
Eastern Edison Company	12/98	Montaup Electric Company	D.T.E. 99-9	Sale of Nuclear Plant
NStar	9/07, 12/07	NStar, Bay State Gas, Fitchburg G&E, NE Gas, W. MA Electric	DPU 07-50	Decoupling
Mass. Energy Facilities Siting Council				
Mass. Institute of Technology	1/89	M.M.W.E.C.	EFSC-88-1	Least-Cost Planning
Boston Edison Company	9/90	Boston Edison	EFSC-90-12	Electric Generation Mkts
Silver City Energy Ltd. Partnership	11/91	Silver City Energy	D.P.U. 91-100	State Policies; Need for Facility
Michigan Public Service Commission				
Detroit Edison Company	9/98	Detroit Edison Company	Case No. U-11726	Market Value of Generation Assets
Consumers Energy Company	8/06	Consumers Energy Company	Case No. U-14992	Sale of Nuclear Plant
Minnesota Public Utilities Commission				
Xcel Energy/No. States Power	9/04	Xcel Energy/No. States Power	Docket No. G002/GR-04-1511	NRG Impacts
Interstate Power and Light	8/05	Interstate Power and Light and FPL Energy Duane Arnold, LLC	Docket No. E001/PA-05-1272	Sale of Nuclear Plant
Northern States Power Company d/b/a Xcel Energy	11/05	Northern States Power Company	Docket No. E002/GR-05-1428	NRG Impacts on Debt Costs
Northern States Power Company d/b/a Xcel Energy	09/06	NSP v. Excelsior	Docket No. E6472/M-05-1993	Industry Norms and Financial Impacts

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Northern States Power Company d/b/a Xcel Energy	11/06	Northern States Power Company	Docket No. G002/GR-06-1429	Return on Equity
Missouri Public Service Commission				
Missouri Gas Energy	1/03	Missouri Gas Energy	Case No. GR-2001-382	Gas Purchasing Practices; Prudence
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case Nos. ER-2004-0034 HR-2004-0024	Cost of Capital, Capital Structure
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case No. GR-2004-0072	Cost of Capital, Capital Structure
Missouri Gas Energy	11/05	Missouri Gas Energy	Case Nos. GR-2002-348 GR-2003-0330	Capacity Planning
Montana Public Service Commission				
Great Falls Gas Company	10/82	Great Falls Gas Company	Docket No. 82-4-25	Gas Rate Adjust. Clause
Nat. Energy Board of Canada				
Alberta-Northeast	2/87	Alberta Northeast Gas Export Project	Docket No. GH-1-87	Gas Export Markets
Alberta-Northeast	11/87	TransCanada Pipeline	Docket No. GH-2-87	Gas Export Markets
Alberta-Northeast	1/90	TransCanada Pipeline	Docket No. GH-5-89	Gas Export Markets
Indep. Petroleum Association of Canada	1/92	Interprovincial Pipe Line, Inc.	RH-2-91	Pipeline Valuation, Toll
The Canadian Association of Petroleum Producers	11/93	Transmountain Pipe Line	RH3-93	Cost of Capital
Alliance Pipeline L.P.	6/97	Alliance Pipeline L.P.	GH-3-97	Market Study
Maritimes & Northeast Pipeline	97	Sable Offshore Energy Project	GH-6-96	Market Study
Maritimes & Northeast Pipeline	2/02	Maritimes & Northeast Pipeline	GH-3-2002	Natural Gas Demand Analysis
TransCanada Pipelines	8/04	TransCanada Pipelines	RH-3-2004	Segmented Service
Brunswick Pipeline	9/06	Brunswick Pipeline	GH-1-2006	Market Study
TransCanada Pipelines Ltd.	3/07	TransCanada Pipelines Ltd.: Gros Cacouna Receipt Point Application	RH-1-2007	
Repsol Energy Canada Ltd	3/08	Repsol Energy Canada Ltd	GH-1-2008	Market Study
New Brunswick Energy and Utilities Board				
Atlantic Wallboard/JD Irving Co	1/08	Atlantic Wallboard/JD Irving Co.	MCTN #298600	Rate Setting for EGNB
NH Public Utilities Commission				
Bus & Industry Association	6/89	P.S. Co. of New Hampshire	Docket No. DR89-091	Fuel Costs
Bus & Industry Association	5/90	Northeast Utilities	Docket No. DR89-244	Merger & Acq. Issues
Eastern Utilities Associates	6/90	Eastern Utilities Associates	Docket No. DF89-085	Merger & Acq. Issues
EnergyNorth Natural Gas	12/90	EnergyNorth Natural Gas	Docket No. DE90-166	Gas Purchasing Practices
EnergyNorth Natural Gas	7/90	EnergyNorth Natural Gas	Docket No. DR90-187	Special Contracts, Discounted Rates
Northern Utilities, Inc.	12/91	Commission Investigation	Docket No. DR91-172	Generic Discounted Rates
New Jersey Board of Public Utilities				
Hilton/Golden Nugget	12/83	Atlantic Electric	B.P.U. 832-154	Line Extension Policies
Golden Nugget	3/87	Atlantic Electric	B.P.U. No. 837-658	Line Extension Policies

Sponsor	Date	Case/Applicant	Docket No.	Subject
New Jersey Natural Gas	2/89	New Jersey Natural Gas	B.P.U. GR89030335J	Cost Alloc./Rate Design
New Jersey Natural Gas	1/91	New Jersey Natural Gas	B.P.U. GR90080786J	Cost Alloc./Rate Design
New Jersey Natural Gas	8/91	New Jersey Natural Gas	B.P.U. GR91081393J	Rate Design; Weather Norm. Clause
New Jersey Natural Gas	4/93	New Jersey Natural Gas	B.P.U. GR93040114J	Cost Alloc./Rate Design
South Jersey Gas	4/94	South Jersey Gas	BRC Dock No. GR080334	Revised levelized gas adjustment
New Jersey Utilities Association	9/96	Commission Investigation	BPU AX96070530	PBOP Cost Recovery
New Mexico Public Service Commission				
Gas Company of New Mexico	11/83	Public Service Co. of New Mexico	Docket No. 1835	Cost Alloc./Rate Design
New York Public Service Commission				
Iroquois Gas. Transmission	12/86	Iroquois Gas Transmission System	Case No. 70363	Gas Markets
Brooklyn Union Gas Company	8/95	Brooklyn Union Gas Company	Case No. 95-6-0761	Panel on Industry Directions
Central Hudson, ConEdison and Niagara Mohawk	9/00	Central Hudson, ConEdison and Niagara Mohawk	Case No. 96-E-0909 Case No. 96-E-0897 Case No. 94-E-0098 Case No. 94-E-0099	Section 70
Central Hudson, New York State Electric & Gas, Rochester Gas & Electric	5/01	Joint Petition of NiMo, NYSEG, RG&E, Central Hudson, Constellation and Nine Mile Point	Case No. 01-E-0011	Section 70, Rebuttal Testimony
Rochester Gas & Electric	12/03	Rochester Gas & Electric	Case No. 03-E-1231	Sale of Nuclear Plant
Rochester Gas & Electric	01/04	Rochester Gas & Electric	Case No. 03-E-0765 Case No. 02-E-0198 Case No. 03-E-0766	Sale of Nuclear Plant; Ratemaking Treatment of Sale
Oklahoma Corporation Commission				
Oklahoma Natural Gas Company	6/98	Oklahoma Natural Gas Company	Case PUD No. 980000177	Evaluate their use of storage
Oklahoma Gas & Electric Company	9/05	Oklahoma Gas & Electric Company	Cause No. PUD 200500151	Prudence of McLain Acquisition
Oklahoma Gas & Electric Company	03/08	Oklahoma Gas & Electric Company	Cause No. PUD 200800086	Acquisition of Redbud generating facility
Ontario Energy Board				
Market Hub Partners Canada, L.P.	5/06	Natural Gas Electric Interface Roundtable	File No. EB-2005-0551	Market-based Rates For Storage
Pennsylvania Public Utility Commission				
ATOC	4/95	Equitrans	Docket No. R-00943272	Tariff Changes
ATOC	3/96	Equitrans	Docket No. P-00940886	Rate Service - Direct
Rhode Island Public Utilities Commission				
Newport Electric	7/81	Newport Electric	Docket No. 1599	Rate Attrition
South County Gas	9/82	South County Gas	Docket No. 1671	Cost of Capital
New England Energy Group	7/86	Providence Gas Company	Docket No. 1844	Cost Alloc./Rate Design
Providence Gas	8/88	Providence Gas Company	Docket No. 1914	Load Forecast., Least-Cost Planning
Providence Gas Company and The Valley Gas Company	1/01	Providence Gas Company and The Valley Gas Company	Docket No. 1673 and 1736	Gas Cost Mitigation Strategy

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
The New England Gas Company	3/03	New England Gas Company	Docket No. 3459	Cost of Capital
Texas Public Utility Commission				
Southwestern Electric	5/83	Southwestern Electric		Cost of Capital, CWIP
P.U.C. General Counsel	11/90	Texas Utilities Electric Company	Docket No. 9300	Gas Purchasing Practices
Oncor Electric Delivery Company	8/07	Oncor Electric Delivery Company	Docket No. 34040	Rate Filing Package; Regulatory Policy, Rate of Return, Return of Capital and Consolidated Tax Adjustment
Oncor Electric Delivery Company	6/08	Oncor Electric Delivery Company	Docket No.35717	Rate Filing
Texas Railroad Commission				
Southern Union Gas	5/85	Southern Union Gas Company	G.U.D. 1891	Cost of Service
Utah Public Service Commission				
AMAX Magnesium	1/88	Mountain Fuel Supply Company	Case No. 86-057-07	Cost Alloc./Rate Design
AMAX Magnesium	4/88	Utah P&L/Pacific P&L	Case No. 87-035-27	Merger & Acquisition
Utah Industrial Group	7/90	Mountain Fuel Supply	Case No. 89-057-15	Gas Transportation Rates
AMAX Magnesium	9/90	Utah Power & Light	Case No. 89-035-06	Energy Balancing Account
AMAX Magnesium	8/90	Utah Power & Light	Case No. 90-035-06	Electric Service Priorities
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	benchmarking
Vermont Public Service Board				
Green Mountain Power	8/82	Green Mountain Power	Docket No. 4570	Rate Attrition
Green Mountain Power	12/97	Green Mountain Power	Docket No. 5983	Tariff Filing
Green Mountain Power	7/98	Green Mountain Power	Docket No. 6107	Direct Testimony
Green Mountain Power	9/00	Green Mountain Power	Docket No. 6107	Rebuttal Testimony
Wisconsin Public Service Commission				
WEC & WICOR	11/99	WEC	Docket No. 9401-YO-100 Docket No. 9402-YO-101	Approval to Acquire the Stock of WICOR
Wisconsin Electric Power Company	1/07	Wisconsin Electric Power Co.	Docket No. 6630-EI-113	Sale of Nuclear Plant
SPONSOR	**DATE**	**CASE/APPLICANT**	**DOCKET NO.**	**SUBJECT**
American Arbitration Association				
Michael Polsky	3/91	M. Polsky vs. Indeck Energy		Corporate Valuation, Damages
ProGas Limited	7/92	ProGas Limited v. Texas Eastern	Arbitration Panel	Gas Contract Arbitration
Attala Generating Company	12/03	Attala Generating Co v. Attala Energy Co.	Case No. 16-Y-198-00228-03	Power Project Valuation; Breach of Contract; Damages
Nevada Power Company	4/08	Nevada Power v. Nevada Cogeneration Assoc. #2		Power Purchase Agreement
Commonwealth of Massachusetts, Suffolk Superior Court				
John Hancock	1/84	Trinity Church v. John Hancock	C.A. No. 4452	Damages Quantification
State of Colorado District Court, County of Garfield				

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Questar Corporation, et al	11/00	Questar Corporation, et al.	Case No. 00CV129-A	Partnership Fiduciary Duties
State of Delaware, Court of Chancery, New Castle County				
Wilmington Trust Company	11/05	Calpine Corporation vs. Bank Of New York and Wilmington Trust Company	C.A. No. 1669-N	Bond Indenture Covenants
Illinois Appellate Court, Fifth Division				
Norweb, plc	8/02	Indeck No. America v. Norweb	Docket No. 97 CH 07291	Breach of Contract; Power Plant Valuation
Independent Arbitration Panel				
Alberta Northeast Gas Limited	2/98	ProGas Ltd., Canadian Forest Oil Ltd., AEC Oil & Gas		
Ocean State Power	9/02	Ocean State Power vs. ProGas Ltd.	2001/2002 Arbitration	Gas Price Arbitration
Ocean State Power	2/03	Ocean State Power vs. ProGas Ltd.	2002/2003 Arbitration	Gas Price Arbitration
Ocean State Power	6/04	Ocean State Power vs. ProGas Ltd.	2003/2004 Arbitration	Gas Price Arbitration
Shell Canada Limited	7/05	Shell Canada Limited and Nova Scotia Power Inc.		Gas Contract Price Arbitration
International Court of Arbitration				
Wisconsin Gas Company, Inc.	2/97	Wisconsin Gas Co. vs. Pan-Alberta	Case No. 9322/CK	Contract Arbitration
Minnegasco, A Division of NorAm Energy Corp.	3/97	Minnegasco vs. Pan-Alberta	Case No. 9357/CK	Contract Arbitration
Utilicorp United Inc.	4/97	Utilicorp vs. Pan-Alberta	Case No. 9373/CK	Contract Arbitration
IES Utilities	97	IES vs. Pan-Alberta	Case No. 9374/CK	Contract Arbitration
State of New Jersey, Mercer County Superior Court				
Transamerica Corp., et. al.	7/07	IMO Industries Inc. vs. Transamerica Corp., et. al.	Docket No. L-2140-03	Breach-Related Damages, Enterprise Value
State of New York, Nassau County Supreme Court				
Steel Los III, LP	6/08	Steel Los II, LP & Associated Brook, Corp v. Power Authority of State of NY	Index No. 5662/05	Property seizure
Province of Alberta, Court of Queen's Bench				
Alberta Northeast Gas Limited	5/07	Cargill Gas Marketing Ltd. vs. Alberta Northeast Gas Limited	Action No. 0501-03291	Gas Contracting Practices
State of Rhode Island, Providence City Court				
Aquidneck Energy	5/87	Laroche vs. Newport		Least-Cost Planning
State of Texas Hutchinson County Court				
Western Gas Interstate	5/85	State of Texas vs. Western Gas Interstate Co.	Case No. 14,843	Cost of Service

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
State of Utah Third District Court				
PacifiCorp & Holme, Roberts & Owen, LLP	1/07	USA Power & Spring Canyon Energy vs. PacifiCorp. et. al.	Civil No. 050903412	Breach-Related Damages
U.S. Bankruptcy Court, District of New Hampshire				
EUA Power Corporation	7/92	EUA Power Corporation	Case No. BK-91-10525-JEY	Pre-Petition Solvency
U.S. Bankruptcy Court, District Of New Jersey				
Ponderosa Pine Energy Partners, Ltd.	7/05	Ponderosa Pine Energy Partners, Ltd.	Case No. 05-21444	Forward Contract Bankruptcy Treatment
U.S. Bankruptcy Court, So. District Of New York				
Johns Manville	5/04	Enron Energy Mktg. v. Johns Manville; Enron No. America v. Johns Manville	Case No. 01-16034 (AJG)	Breach of Contract; Damages
U.S. Bankruptcy Court, Northern District Of Texas				
Southern Maryland Electric Cooperative, Inc. and Potomac Electric Power Company	11/04	Mirant Corporation, et al. v. SMECO	Case No. 03-4659; Adversary No. 04-4073	PPA Interpretation; Leasing
U. S. Court of Federal Claims				
Boston Edison Company	7/06	Boston Edison v. Department of Energy	No. 99-447C No. 03-2626C	Spent Nuclear Fuel Litigation
Consolidated Edison of New York	08/07	Consolidated Edison of New York, Inc. and subsidiaries v. United States	No. 06-305T	Leasing Litigation
Consolidated Edison Company	2/08	Consolidated Edison Company v. United States	No. 04-0033C	SNF Expert Report
Vermont Yankee Nuclear Power Corporation	6/08	Vermont Yankee Nuclear Power Corporation	No. 03-2663C	SNF Expert Report
U. S. District Court, Boulder County, Colorado				
KN Energy, Inc.	3/93	KN Energy vs. Colorado GasMark, Inc.	Case No. 92 CV 1474	Gas Contract Interpretation
U. S. District Court, Northern California				
Pacific Gas & Electric Co./PGT PG&E/PGT Pipeline Exp. Project	4/97	Norcen Energy Resources Limited	Case No. C94-0911 VRW	Fraud Claim
U. S. District Court, District of Connecticut				
Constellation Power Source, Inc.	12/04	Constellation Power Source, Inc. v. Select Energy, Inc.	Civil Action 304 CV 983 (RNC)	ISO Structure, Breach of Contract

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
U. S. District Court, Massachusetts				
Eastern Utilities Associates & Donald F. Pardus	3/94	NECO Enterprises Inc. vs. Eastern Utilities Associates	Civil Action No. 92-10355-RCL	Seabrook Power Sales
U. S. District Court, Montana				
KN Energy, Inc.	9/92	KN Energy v. Freeport MacMoRan	Docket No. CV 91-40-BLG-RWA	Gas Contract Settlement
U.S. District Court, New Hampshire				
Portland Natural Gas Transmission and Maritimes & Northeast Pipeline	9/03	Public Service Company of New Hampshire vs. PNGTS and M&NE Pipeline	Docket No. C-02-105-B	Impairment of Electric Transmission Right-of-Way
U. S. District Court, Southern District of New York				
Central Hudson Gas & Electric	11/99	Central Hudson v. Riverkeeper, Inc., Robert H. Boyle, John J. Cronin	Civil Action 99 Civ 2536 (BDP)	Expert Report, Shortnose Sturgeon Case
Central Hudson Gas & Electric	8/00	Central Hudson v. Riverkeeper, Inc., Robert H. Boyle, John J. Cronin	Civil Action 99 Civ 2536 (BDP)	Revised Expert Report, Shortnose Sturgeon Case
Consolidated Edison	3/02	Consolidated Edison v. Northeast Utilities	Case No. 01 Civ. 1893 (JGK) (HP)	Industry Standards for Due Diligence
Merrill Lynch & Company	1/05	Merrill Lynch v. Allegheny Energy, Inc.	Civil Action 02 CV 7689 (HB)	Due Diligence, Breach of Contract, Damages
U. S. District Court, Eastern District of Virginia				
Aquila, Inc.	1/05	VPEM v. Aquila, Inc.	Civil Action 304 CV 411	Breach of Contract, Damages
U. S. District Court, Portland Maine				
ACEC Maine, Inc. et al.	10/91	CIT Financial vs. ACEC Maine	Docket No. 90-0304-B	Project Valuation
Combustion Engineering	1/92	Combustion Eng. vs. Miller Hydro	Docket No. 89-0168P	Output Modeling; Project Valuation
U.S. Securities and Exchange Commission				
Eastern Utilities Association	10/92	EUA Power Corporation	File No. 70-8034	Value of EUA Power
District of Columbia Court City Council				
Potomac Electric Power Co.	7/99	Potomac Electric Power Co.	Bill 13-284	Utility restructuring

Situational Assessment Rankings - 1998

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overall Rank (1 is the most challenged)
Alabama Power Company	19	17	24	10	5	13	20	17	15.6	19
Appalachian Power Company	14	21	19	15	20	16	5	20	16.3	21
Arizona Public Service Company	8	14	11	3	3	7	7	23	9.5	3
Carolina Power & Light Company	17	19	21	4	14	5	27	12	14.9	16
Cleveland Electric Illuminating Company	18	4	6	26	27	8	8	25	15.3	18
Columbus Southern Power Company	9	13	9	5	17	16	6	22	12.1	9
Dayton Power and Light Company	10	18	13	18	21	16	17	16	16.1	20
Detroit Edison Company	15	8	3	22	15	15	13	10	12.6	10
Duke Energy Carolinas, LLC	12	6	16	2	16	4	10	18	10.5	6
Duke Energy Indiana, Inc.	27	27	27	8	13	16	9	11	17.3	24
Entergy Arkansas, Inc.	22	24	23	17	9	2	1	8	13.3	12
Entergy Louisiana, LLC						16				
Florida Power & Light Company	**1**	**2**	**2**	**12**	**4**	**9**	**3**	**2**	**4.4**	**1**
Florida Power Corporation	2	9	5	9	2	12	18	4	7.6	2
Georgia Power Company	16	7	17	6	7	11	19	19	12.8	11
Indiana Michigan Power Company	23	20	20	16	11	16	4	5	14.4	14
Kansas City Power & Light	13	12	15	21	6	10	23	21	15.1	17
Kentucky Utilities Company	21	22	22	11	8	16	24	6	16.3	21
Nevada Power Company	3	5	7	1	1	16	16	27	9.5	3
NSTAR Electric Company	24	16	4	27	24	1	12	26	16.8	23
Ohio Edison Company	11	10	8	20	23	14	14	15	14.4	14
Ohio Power Company	26	23	26	25	25	16	21	9	21.4	27
Oklahoma Gas and Electric Company	5	11	12	24	12	16	2	3	10.6	8
PacifiCorp	25	26	25	7	19	28	15	24	21.1	26
Portland General Electric Company	20	25	18	13	26	16	22	13	19.1	25
Public Service Company of Oklahoma	4	3	10	23	10	16	11	7	10.5	6
Southern California Edison Co.	6	1	1	19	22	3	26	1	9.9	5
Virginia Electric and Power Company	7	15	14	14	18	6	25	14	14.1	13

Regional Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overal Rank
Florida Power & Light Company	**1**	**1**	**1**	**4**	**2**	**1**	**1**	**1**	**1.5**	**1**
Florida Power Corporation	2	2	2	3	1	2	2	2	2.0	2
Gulf Power Company	4	4	4	1	4	3	3	3	3.3	4
Tampa Electric Company	3	3	3	2	3	3	4	4	3.1	3

Large Utility Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overal Rank
Dominion Resources, Inc.	3	6	5	5	7	1	7	5	4.9	6
DTE Energy Company	4	2	2	7	6	7	3	4	4.4	4
Entergy Corporation	6	7	7	6	4	2	2	6	5.0	7
Florida Power & Light Company	**1**	**1**	**1**	**4**	**1**	**4**	**1**	**1**	**1.8**	**1**
Progress Energy, Inc.	2	4	4	2	2	3	6	3	3.3	2
Southern Company	5	3	6	3	3	5	5	7	4.6	5
Xcel Energy, Inc.	7	5	3	1	5	6	4	2	4.1	3

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 170
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS John J. Reed (JJR-3)
DATE 09/05/09

Situational Assessment Rankings - 1999

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	**Percent Sales (MWh) Residential**	**Percent Sales (MWh) Other**	**Use per Customer**	**Change in Customers (%)**	**Change in Sales Vol (Rolling 5 Year CAGR)**	**Percent Generation Nuclear**	**Energy Losses / Total Energy Disposition**	**Accum. Dep./Gross Plant**	**Average Rank**	**Overall Rank (1 is the most challenged)**
Alabama Power Company	19	17	23	16	6	13	20	20	16.8	21
Appalachian Power Company	10	18	17	17	20	16	5	21	15.5	20
Arizona Public Service Company	18	24	18	2	4	8	25	23	15.3	19
Carolina Power & Light Company	17	19	19	6	16	5	23	10	14.4	15
Cleveland Electric Illuminating Company	20	9	7	25	27	7	19	25	17.4	23
Columbus Southern Power Company	8	14	9	7	10	16	12	22	12.3	13
Dayton Power and Light Company	9	15	13	21	24	16	2	15	14.4	15
Detroit Edison Company	14	7	4	22	12	14	8	11	11.5	9
Duke Energy Carolinas, LLC	12	4	15	4	18	4	9	17	10.4	4
Duke Energy Indiana, Inc.	26	27	27	10	2	16	24	16	18.5	25
Entergy Arkansas, Inc.	22	22	22	15	8	2	13	6	13.8	14
Entergy Louisiana, LLC						16				
Florida Power & Light Company	**1**	**2**	**3**	**12**	**14**	**9**	**6**	**2**	**6.1**	**1**
Florida Power Corporation	2	12	5	5	3	15	10	4	7.0	2
Georgia Power Company	15	5	16	8	5	12	18	18	12.1	11
Indiana Michigan Power Company	23	20	20	19	9	16	7	5	14.9	18
Kansas City Power & Light	11	10	11	9	11	10	15	19	12.0	10
Kentucky Utilities Company	24	25	24	14	7	16	21	8	17.4	23
Nevada Power Company	3	6	6	1	1	16	14	27	9.3	3
NSTAR Electric Company	16	8	2	11	22	1	3	26	11.1	7
Ohio Edison Company	13	13	8	18	13	11	26	14	14.5	17
Ohio Power Company	27	21	26	23	26	16	17	7	20.4	26
Oklahoma Gas and Electric Company	6	11	12	24	21	16	4	3	12.1	11
PacifiCorp	25	26	25	27	25	28	16	24	24.5	27
Portland General Electric Company	21	23	21	3	17	16	22	13	17.0	22
Public Service Company of Oklahoma	4	3	10	20	15	16	11	9	11.0	6
Southern California Edison Co.	7	1	1	26	23	3	27	1	11.1	7
Virginia Electric and Power Company	5	16	14	13	19	6	1	12	10.8	5

Regional Group	**Percent Sales (MWh) Residential**	**Percent Sales (MWh) Other**	**Use per Customer**	**Change in Customers (%)**	**Change in Sales Vol (Rolling 5 Year CAGR)**	**Percent Generation Nuclear**	**Energy Losses / Total Energy Disposition**	**Accum. Dep./Gross Plant**	**Average Rank**	**Overal Rank**
Florida Power & Light Company	**1**	**1**	**1**	**4**	**3**	**1**	**1**	**1**	**1.6**	**1**
Florida Power Corporation	2	3	2	2	1	2	2	2	2.0	2
Gulf Power Company	4	4	4	1	2	3	4	3	3.1	3
Tampa Electric Company	3	2	3	3	4	3	3	4	3.1	3

Large Utility Group	**Percent Sales (MWh) Residential**	**Percent Sales (MWh) Other**	**Use per Customer**	**Change in Customers (%)**	**Change in Sales Vol (Rolling 5 Year CAGR)**	**Percent Generation Nuclear**	**Energy Losses / Total Energy Disposition**	**Accum. Dep./Gross Plant**	**Average Rank**	**Overal Rank**
Dominion Resources, Inc.	3	4	5	4	5	1	1	6	3.6	3
DTE Energy Company	4	2	2	6	3	5	3	5	3.8	4
Entergy Corporation	6	5	7	5	6	2	6	4	5.1	6
Florida Power & Light Company	**1**	**1**	**1**	**2**	**4**	**4**	**2**	**1**	**2.0**	**1**
Progress Energy, Inc.	2	6	4	1	2	3	5	2	3.1	2
Southern Company	5	3	6	3	1	7	7	7	4.9	5
Xcel Energy, Inc.	7	7	3	7	7	6	4	3	5.5	7

Situational Assessment Rankings - 2000

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overall Rank (1 is the most challenged)
Alabama Power Company	19	16	23	14	8	14	26	22	17.8	22
Appalachian Power Company	18	23	21	18	25	16	13	19	19.1	25
Arizona Public Service Company	9	19	16	2	2	7	23	23	12.6	11
Carolina Power & Light Company	13	17	18	3	16	5	24	7	12.9	12
Cleveland Electric Illuminating Company	22	11	8	27	27	4	6	24	16.1	20
Columbus Southern Power Company	16	18	14	4	20	16	19	20	15.9	19
Dayton Power and Light Company	11	15	10	25	26	16	5	10	14.8	15
Detroit Edison Company	14	5	4	20	22	15	10	15	13.1	13
Duke Energy Carolinas, LLC	10	6	15	6	23	3	17	17	12.1	9
Duke Energy Indiana, Inc.	27	27	27	8	15	16	3	16	17.4	21
Entergy Arkansas, Inc.	21	21	19	22	12	2	15	11	15.4	18
Entergy Louisiana, LLC						16				
Florida Power & Light Company	**1**	**2**	**3**	**5**	**13**	**8**	**4**	**2**	**4.8**	**2**
Florida Power Corporation	2	12	5	11	6	13	11	3	7.9	3
Georgia Power Company	17	8	17	7	5	12	8	18	11.5	8
Indiana Michigan Power Company	25	24	25	24	17	11	12	5	17.9	23
Kansas City Power & Light	8	7	9	15	4	9	18	21	11.4	7
Kentucky Utilities Company	20	20	20	10	7	16	20	6	14.9	16
Nevada Power Company	3	9	7	1	1	16	21	27	10.6	5
NSTAR Electric Company	15	3	2	23	18	16	9	26	14.0	14
Ohio Edison Company	12	13	6	19	24	10	27	9	15.0	17
Ohio Power Company	26	26	26	21	14	16	22	8	19.9	26
Oklahoma Gas and Electric Company	6	10	12	26	11	16	14	4	12.4	10
PacifiCorp	24	22	22	13	21	28	16	25	21.4	27
Portland General Electric Company	23	25	24	12	10	16	25	12	18.4	24
Public Service Company of Oklahoma	5	4	11	17	3	16	2	14	9.0	4
Southern California Edison Co.	7	1	1	16	9	1	1	1	4.6	1
Virginia Electric and Power Company	4	14	13	9	19	6	7	13	10.6	5

Regional Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overal Rank
Florida Power & Light Company	**1**	**1**	**1**	**2**	**3**	**1**	**1**	**1**	**1.4**	**1**
Florida Power Corporation	2	2	2	4	2	2	2	2	2.3	2
Gulf Power Company	4	4	4	3	1	3	4	3	3.3	4
Tampa Electric Company	3	3	3	1	4	3	3	4	3.0	3

Large Utility Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overal Rank
Dominion Resources, Inc.	2	3	3	4	5	1	2	4	3.0	2
DTE Energy Company	4	2	2	6	6	5	3	6	4.3	4
Entergy Corporation	6	6	7	5	7	2	4	5	5.3	6
Florida Power & Light Company	**1**	**1**	**1**	**1**	**3**	**4**	**1**	**1**	**1.6**	**1**
Progress Energy, Inc.	3	5	4	2	2	3	5	2	3.3	3
Southern Company	5	4	6	3	1	6	7	7	4.9	5
Xcel Energy, Inc.	7	7	5	7	4	7	6	3	5.8	7

Situational Assessment Rankings - 2001

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overall Rank (1 is the most challenged)
Alabama Power Company	20	15	22	15	17	14	16	23	17.8	24
Appalachian Power Company				16	22	16	22	22	19.6	26
Arizona Public Service Company	4	13	9	2	2	9	12	24	9.4	5
Carolina Power & Light Company	12	12	15	6	19	7	19	8	12.3	10
Cleveland Electric Illuminating Company	22	22	18	25	26	2	27	21	20.4	27
Columbus Southern Power Company				11	9	16	24	18	15.6	21
Dayton Power and Light Company	11	14	8	20	27	16	11	9	14.5	16
Detroit Edison Company	9	4	4	18	21	15	6	15	11.5	8
Duke Energy Carolinas, LLC	8	5	13	5	25	6	8	16	10.8	7
Duke Energy Indiana, Inc.	23	23	23	12	7	16	9	17	16.3	23
Entergy Arkansas, Inc.	19	20	20	21	8	3	10	12	14.1	14
Entergy Louisiana, LLC						16				
Florida Power & Light Company	**1**	**2**	**3**	**7**	**5**	**10**	**4**	**2**	**4.3**	**1**
Florida Power Corporation	2	9	5	3	6	13	18	3	7.4	3
Georgia Power Company	15	7	16	8	14	12	15	19	13.3	12
Indiana Michigan Power Company				24	18	4	23	5	14.8	19
Kansas City Power & Light	10	10	10	9	13	11	14	20	12.1	9
Kentucky Utilities Company	16	18	21	14	11	16	13	7	14.5	16
Nevada Power Company	13	21	17	1	1	16	21	27	14.6	18
NSTAR Electric Company	14	3	2	27	12	16	3	26	12.9	11
Ohio Edison Company	18	17	11	19	23	1	20	6	14.4	15
Ohio Power Company				23	3	16	25	10	15.4	20
Oklahoma Gas and Electric Company	5	8	7	26	10	16	5	4	10.1	6
PacifiCorp	21	16	19	13	24	28	7	25	19.1	25
Portland General Electric Company	17	19	14	17	16	16	17	11	15.9	22
Public Service Company of Oklahoma	7	6	12	22	4	16	26	14	13.4	13
Southern California Edison Co.	6	1	1	4	20	5	1	1	4.9	2
Virginia Electric and Power Company	3	11	6	10	15	8	2	13	8.5	4

Regional Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overal Rank
Florida Power & Light Company	**1**	**1**	**1**	**3**	**1**	**1**	**1**	**1**	**1.3**	**1**
Florida Power Corporation	2	3	2	1	3	2	3	2	2.3	2
Gulf Power Company	4	4	4	4	2	3	2	3	3.3	4
Tampa Electric Company	3	2	3	2	4	3	4	4	3.1	3

Large Utility Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overal Rank
Dominion Resources, Inc.	3	3	4	3	5	2	1	4	3.1	3
DTE Energy Company	4	2	2	6	6	5	3	6	4.3	4
Entergy Corporation	5	5	7	7	7	1	6	5	5.4	5
Florida Power & Light Company	**1**	**1**	**1**	**2**	**1**	**4**	**2**	**1**	**1.6**	**1**
Progress Energy, Inc.	2	4	3	1	3	3	5	2	2.9	2
Southern Company	6	6	6	4	4	6	4	7	5.4	5
Xcel Energy, Inc.	7	7	5	5	2	7	7	3	5.4	5

Situational Assessment Rankings - 2002

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overall Rank (1 is the most challenged)
Alabama Power Company	18	16	24	17	13	15	21	23	18.4	22
Appalachian Power Company	17	19	22	18	20	16	10	20	17.8	21
Arizona Public Service Company	3	10	5	2	4	9	14	24	8.9	5
Carolina Power & Light Company	13	13	19	3	18	7	24	7	13.0	11
Cleveland Electric Illuminating Company	24	22	16	20	27	2	27	19	19.6	25
Columbus Southern Power Company	12	17	11	9	6	16	18	17	13.3	12
Dayton Power and Light Company	11	14	12	24	24	16	13	10	15.5	18
Detroit Edison Company	10	5	3	21	22	14	7	15	12.1	10
Duke Energy Carolinas, LLC	9	4	14	11	19	6	6	16	10.6	8
Duke Energy Indiana, Inc.	26	27	27	10	5	16	5	22	17.3	19
Entergy Arkansas, Inc.	21	21	21	26	11	3	3	11	14.6	16
Entergy Louisiana, LLC						16				
Florida Power & Light Company	**1**	**2**	**2**	**4**	**2**	**10**	**4**	**2**	**3.4**	**1**
Florida Power Corporation	2	7	4	5	3	13	9	4	5.9	2
Georgia Power Company	16	6	18	7	9	12	25	21	14.3	14
Indiana Michigan Power Company	25	26	25	23	14	5	17	3	17.3	19
Kansas City Power & Light	15	12	15	8	16	11	20	18	14.4	15
Kentucky Utilities Company	14	15	20	13	7	16	15	8	13.5	13
Nevada Power Company	6	11	8	1	1	16	23	27	11.6	9
NSTAR Electric Company	23	20	7	27	15	16	16	26	18.8	24
Ohio Edison Company	19	18	13	22	21	1	19	6	14.9	17
Ohio Power Company	27	25	26	25	10	16	26	12	20.9	26
Oklahoma Gas and Electric Company	7	8	9	16	17	16	2	5	10.0	7
PacifiCorp	22	23	23	12	26	28	12	25	21.4	27
Portland General Electric Company	20	24	17	15	25	16	22	9	18.5	23
Public Service Company of Oklahoma	5	3	6	19	12	16	1	14	9.5	6
Southern California Edison Co.	8	1	1	14	23	4	8	1	7.5	3
Virginia Electric and Power Company	4	9	10	6	8	8	11	13	8.6	4

Regional Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overal Rank
Florida Power & Light Company	**1**	**1**	**1**	**2**	**2**	**1**	**1**	**1**	**1.3**	**1**
Florida Power Corporation	2	3	2	3	3	2	2	2	2.4	2
Gulf Power Company	4	4	4	4	1	3	3	3	3.3	4
Tampa Electric Company	3	2	3	1	4	3	4	4	3.0	3

Large Utility Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overal Rank
Dominion Resources, Inc.	2	3	3	3	2	2	3	4	2.8	2
DTE Energy Company	4	2	2	7	6	5	2	6	4.3	4
Entergy Corporation	5	5	5	5	7	1	4	5	4.6	5
Florida Power & Light Company	**1**	**1**	**1**	**2**	**1**	**4**	**1**	**1**	**1.5**	**1**
Progress Energy, Inc.	3	4	4	1	4	3	5	2	3.3	3
Southern Company	6	6	6	4	3	7	7	7	5.8	7
Xcel Energy, Inc.				6	5	6	6	3	5.2	6

Situational Assessment Rankings - 2003

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overall Rank (1 is the most challenged)
Alabama Power Company	20	16	25	18	16	13	19	23	18.8	23
Appalachian Power Company	18	24	23	21	22	16	14	20	19.8	25
Arizona Public Service Company	14	25	22	2	2	8	26	24	15.4	18
Carolina Power & Light Company	10	12	17	6	20	7	23	8	12.9	9
Cleveland Electric Illuminating Company	25	20	13	25	25	3	27	14	19.0	24
Columbus Southern Power Company	16	21	14	13	7	16	11	15	14.1	12
Dayton Power and Light Company	11	15	11	22	26	16	10	27	17.3	22
Detroit Edison Company	7	3	2	24	11	14	5	12	9.8	6
Duke Energy Carolinas, LLC	9	2	12	27	27	6	7	13	12.9	9
Duke Energy Indiana, Inc.	23	19	24	15	9	16	2	22	16.3	20
Entergy Arkansas, Inc.	21	22	21	7	14	2	9	17	14.1	12
Entergy Louisiana, LLC						16				
Florida Power & Light Company	**1**	**1**	**3**	**3**	**4**	**10**	**3**	**5**	**3.8**	**1**
Florida Power Corporation	2	8	4	4	5	15	6	7	6.4	3
Georgia Power Company	15	7	18	5	13	11	25	19	14.1	12
Indiana Michigan Power Company	26	27	26	20	23	5	8	2	17.1	21
Kansas City Power & Light	13	13	16	10	19	12	22	11	14.5	17
Kentucky Utilities Company	12	14	19	17	10	16	16	9	14.1	12
Nevada Power Company	3	5	6	1	1	16	20	25	9.6	5
NSTAR Electric Company	22	11	5	12	8	16	13	26	14.1	12
Ohio Edison Company	19	17	10	19	18	1	12	4	12.5	8
Ohio Power Company	27	26	27	23	3	16	24	16	20.3	27
Oklahoma Gas and Electric Company	5	9	8	14	17	16	4	3	9.5	4
PacifiCorp	24	18	20	8	24	28	17	21	20.0	26
Portland General Electric Company	17	23	15	16	15	16	21	6	16.1	19
Public Service Company of Oklahoma	6	6	9	26	21	16	18	10	14.0	11
Southern California Edison Co.	8	4	1	11	12	4	1	1	5.3	2
Virginia Electric and Power Company	4	10	7	9	6	9	15	18	9.8	6

Regional Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overal Rank
Florida Power & Light Company	**1**	**1**	**1**	**2**	**1**	**1**	**1**	**1**	**1.1**	**1**
Florida Power Corporation	2	3	2	3	4	2	2	2	2.5	2
Gulf Power Company	4	4	4	4	2	3	4	3	3.5	4
Tampa Electric Company	3	2	3	1	3	3	3	4	2.8	3

Large Utility Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overal Rank
Dominion Resources, Inc.	2	3	3	3	2	2	3	6	3.0	2
DTE Energy Company	4	2	1	7	4	5	2	4	3.6	3
Entergy Corporation	5	5	6	5	7	1	4	5	4.8	5
Florida Power & Light Company	**1**	**1**	**2**	**1**	**1**	**4**	**1**	**1**	**1.5**	**1**
Progress Energy, Inc.	3	4	5	2	5	3	5	2	3.6	3
Southern Company	6	7	7	4	6	6	7	7	6.3	7
Xcel Energy, Inc.	7	6	4	6	3	7	6	3	5.3	6

Situational Assessment Rankings - 2004

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overall Rank (1 is the most challenged)
Alabama Power Company	19	16	23	14	14	13	18	23	17.5	21
Appalachian Power Company	4	1	7	23	20	16	22	22	14.4	15
Arizona Public Service Company	23	26	25	2	3	9	27	24	17.4	20
Carolina Power & Light Company	11	14	18	7	11	7	23	8	12.4	10
Cleveland Electric Illuminating Company	25	24	21	26	23	2	26	13	20.0	27
Columbus Southern Power Company	16	21	15	11	16	16	11	14	15.0	16
Dayton Power and Light Company	12	15	12	25	24	16	10	27	17.6	22
Detroit Edison Company	8	10	2	24	2	15	4	12	9.6	5
Duke Energy Carolinas, LLC	9	5	14	8	25	6	8	17	11.5	9
Duke Energy Indiana, Inc.	24	23	24	21	18	16	12	19	19.6	26
Entergy Arkansas, Inc.	21	22	22	17	19	3	7	15	15.8	17
Entergy Louisiana, LLC						16				
Florida Power & Light Company	**1**	**2**	**3**	**3**	**4**	**10**	**3**	**6**	**4.0**	**1**
Florida Power Corporation	2	11	5	4	6	14	5	7	6.8	3
Georgia Power Company	14	6	19	5	9	12	25	20	13.8	12
Indiana Michigan Power Company	26	27	26	22	26	4	17	2	18.8	24
Kansas City Power & Light	17	18	17	16	21	11	24	11	16.9	19
Kentucky Utilities Company	15	17	20	13	8	16	14	10	14.1	14
Nevada Power Company	3	4	4	1	1	16	16	25	8.8	4
NSTAR Electric Company	22	13	6	27	13	16	19	26	17.8	23
Ohio Edison Company	20	20	13	18	27	1	9	3	13.9	13
Ohio Power Company	27	25	27	19	5	16	21	16	19.5	25
Oklahoma Gas and Electric Company	7	8	9	15	17	16	2	5	9.9	6
PacifiCorp	18	12	16	6	22	28	6	21	16.1	18
Portland General Electric Company	13	19	11	10	12	16	20	4	13.1	11
Public Service Company of Oklahoma	6	3	8	20	10	16	15	9	10.9	8
Southern California Edison Co.	10	7	1	12	15	5	1	1	6.5	2
Virginia Electric and Power Company	5	9	10	9	7	8	13	18	9.9	6

Regional Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overal Rank
Florida Power & Light Company	1	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1.0**	**1**
Florida Power Corporation	2	3	2	2	4	2	2	2	2.4	2
Gulf Power Company	4	4	4	4	3	3	4	3	3.6	4
Tampa Electric Company	3	2	3	3	2	3	3	4	2.9	3

Large Utility Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overal Rank
Dominion Resources, Inc.	2	2	4	3	3	2	5	5	3.3	4
DTE Energy Company	4	3	1	6	1	5	2	3	3.1	2
Entergy Corporation	5	5	5	5	6	1	3	4	4.3	5
Florida Power & Light Company	**1**	**1**	**2**	**1**	**2**	**4**	**1**	**1**	**1.6**	**1**
Progress Energy, Inc.	3	4	3	2	4	3	4	2	3.1	2
Southern Company	6	6	6	4	5	6	6	6	5.6	6
Xcel Energy, Inc.						7				

Situational Assessment Rankings - 2005

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overall Rank (1 is the most challenged)
Alabama Power Company	22	15	24	15	14	12	22	22	18.3	24
Appalachian Power Company	19	23	23	21	15	16	8	23	18.5	25
Arizona Public Service Company	15	24	20	2	1	9	24	24	14.9	15
Carolina Power & Light Company	11	16	17	6	20	7	21	5	12.9	10
Cleveland Electric Illuminating Company	25	25	21	16	26	2	26	17	19.8	26
Columbus Southern Power Company	13	19	13	20	10	16	13	16	15.0	17
Dayton Power and Light Company	8	13	7	24	22	16	7	27	15.5	18
Detroit Edison Company	7	6	2	25	9	14	9	11	10.4	7
Duke Energy Carolinas, LLC	9	3	14	7	27	6	4	15	10.6	8
Duke Energy Indiana, Inc.	24	21	25	12	8	16	1	19	15.8	19
Entergy Arkansas, Inc.	16	18	18	22	11	3	5	13	13.3	12
Entergy Louisiana, LLC						16				
Florida Power & Light Company	**1**	**1**	**3**	**3**	**3**	**10**	**2**	**7**	**3.8**	**1**
Florida Power Corporation	2	11	6	4	6	15	11	8	7.9	2
Georgia Power Company	20	10	19	9	16	13	27	18	16.5	21
Indiana Michigan Power Company	26	27	26	26	18	4	16	1	18.0	23
Kansas City Power & Light	12	14	16	17	21	11	17	10	14.8	14
Kentucky Utilities Company	14	17	22	14	7	16	10	6	13.3	12
Nevada Power Company	3	2	5	1	2	16	19	25	9.1	5
NSTAR Electric Company	18	5	4	23	13	16	14	26	14.9	15
Ohio Edison Company	21	20	11	18	23	1	23	12	16.1	20
Ohio Power Company	27	26	27	27	19	16	20	20	22.8	27
Oklahoma Gas and Electric Company	5	8	8	13	17	16	3	4	9.3	6
PacifiCorp	23	12	15	5	25	28	6	21	16.9	22
Portland General Electric Company	17	22	12	10	5	16	18	3	12.9	10
Public Service Company of Oklahoma	6	4	10	19	12	16	25	9	12.6	9
Southern California Edison Co.	10	7	1	11	24	5	12	2	9.0	4
Virginia Electric and Power Company	4	9	9	8	4	8	15	14	8.9	3

Regional Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overal Rank
Florida Power & Light Company	**1**	**1**	**1**	**2**	**1**	**1**	**1**	**1**	**1.1**	**1**
Florida Power Corporation	2	3	2	3	3	2	2	2	2.4	2
Gulf Power Company	4	4	4	4	4	3	4	3	3.8	4
Tampa Electric Company	3	2	3	1	2	3	3	4	2.6	3

Large Utility Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overal Rank
Dominion Resources, Inc.	2	3	4	3	2	2	5	6	3.4	3
DTE Energy Company	4	2	1	5	3	5	3	4	3.4	3
Entergy Corporation	5	5	6	6	7	1	2	5	4.6	5
Florida Power & Light Company	**1**	**1**	**2**	**1**	**1**	**4**	**1**	**2**	**1.6**	**1**
Progress Energy, Inc.	3	4	3	2	4	3	4	1	3.0	2
Southern Company	6	6	7	4	6	7	6	7	6.1	7
Xcel Energy, Inc.	7	7	5		5	6	7	3	5.7	6

Situational Assessment Rankings - 2006

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overall Rank (1 is the most challenged)
Alabama Power Company	21	19	26	18	7	12	23	20	18.3	21
Appalachian Power Company	26	25	25	21	5	16	6	25	18.6	24
Arizona Public Service Company	6	22	14	3	2	9	10	23	11.1	8
Carolina Power & Light Company	14	21	19	7	17	7	25	4	14.3	16
Cleveland Electric Illuminating Company	23	10	8	27	25	16	28	22	19.9	27
Columbus Southern Power Company	17	23	15	4	4	16	18	15	14.0	14
Dayton Power and Light Company	13	20	11	24	26	16	9	28	18.4	23
Detroit Edison Company	11	8	4	23	27	15	4	12	13.0	11
Duke Energy Carolinas, LLC	10	3	12	9	21	6	5	14	10.0	6
Duke Energy Indiana, Inc.	19	17	22	20	13	16	26	18	18.9	25
Entergy Arkansas, Inc.	22	24	24	16	12	2	15	11	15.8	19
Entergy Louisiana, LLC	12	5	23			4	12	17	12.2	9
Florida Power & Light Company	**1**	**1**	**3**	**8**	**6**	**10**	**1**	**6**	**4.5**	**1**
Florida Power Corporation	2	13	6	5	11	14	16	8	9.4	4
Georgia Power Company	18	14	21	1	3	13	27	16	14.1	15
Indiana Michigan Power Company	28	28	27	25	22	5	22	1	19.8	26
Kansas City Power & Light	15	16	16	17	14	11	21	10	15.0	18
Kentucky Utilities Company	16	18	20	15	9	16	8	7	13.6	13
Nevada Power Company	3	2	7	2	1	16	17	26	9.3	3
NSTAR Electric Company	20	7	2	13	20	16	14	27	14.9	17
Ohio Edison Company	7	6	5	22	23	1	19	19	12.8	10
Ohio Power Company	27	27	28	26	18	16	13	24	22.4	28
Oklahoma Gas and Electric Company	5	11	10	14	16	16	2	5	9.9	5
PacifiCorp	25	15	17	6	15	28	3	21	16.3	20
Portland General Electric Company	24	26	18	11	24	16	24	3	18.3	21
Public Service Company of Oklahoma	8	9	13	19	19	16	11	9	13.0	11
Southern California Edison Co.	9	4	1	12	8	3	7	2	5.8	2
Virginia Electric and Power Company	4	12	9	10	10	8	20	13	10.8	7

Regional Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overal Rank
Florida Power & Light Company	**1**	**1**	**1**	**4**	**1**	**1**	**1**	**1**	**1.4**	**1**
Florida Power Corporation	2	3	2	3	4	2	3	2	2.6	2
Gulf Power Company	4	4	4	2	2	3	4	3	3.3	4
Tampa Electric Company	3	2	3	1	3	3	2	4	2.6	2

Large Utility Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overal Rank
Dominion Resources, Inc.	2	3	4	4	2	2	4	6	3.4	3
DTE Energy Company	4	2	2	7	6	6	2	5	4.3	4
Entergy Corporation	6	6	7	6	7	1	3	4	5.0	6
Florida Power & Light Company	**1**	**1**	**1**	**3**	**1**	**4**	**1**	**2**	**1.8**	**1**
Progress Energy, Inc.	3	4	3	2	4	3	5	1	3.1	2
Southern Company	5	5	6	5	3	7	7	7	5.6	7
Xcel Energy, Inc.	7	7	5	1	5	5	6	3	4.9	5

Situational Assessment Rankings - 2007

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overall Rank (1 is the most challenged)
Alabama Power Company	21	18	25	12	14	12	16	20	17.3	21
Appalachian Power Company	26	25	26	19	4	16	14	24	19.3	25
Arizona Public Service Company	3	10	9	1	1	9	6	23	7.8	3
Carolina Power & Light Company	14	21	18	5	20	7	25	2	14.0	16
Cleveland Electric Illuminating Company	20	9	8	22	22	16	22	21	17.5	22
Columbus Southern Power Company	25	24	21	18	3	16	20	16	17.9	23
Dayton Power and Light Company	11	19	12	26	24	16	8	28	18.0	24
Detroit Edison Company	13	7	4	23	25	15	13	12	14.0	16
Duke Energy Carolinas, LLC	8	3	13	4	21	6	9	10	9.3	4
Duke Energy Indiana, Inc.	22	22	24	15	13	16	28	19	19.9	27
Entergy Arkansas, Inc.	23	23	22	20	12	3	5	8	14.5	18
Entergy Louisiana, LLC	15	4	23	16		5	11	7	11.6	7
Florida Power & Light Company	**1**	**1**	**3**	**6**	**11**	**11**	**2**	**6**	**5.1**	**1**
Florida Power Corporation	2	15	6	17	18	14	12	14	12.3	9
Georgia Power Company	18	12	20	7	5	13	18	18	13.9	15
Indiana Michigan Power Company	27	28	27	24	23	4	23	1	19.6	26
Kansas City Power & Light	17	20	17	21	8	10	19	9	15.1	19
Kentucky Utilities Company	12	17	19	14	10	16	7	15	13.8	13
Nevada Power Company	4	2	7	2	2	16	21	27	10.1	5
NSTAR Electric Company	16	8	2			16	15	26	13.8	14
Ohio Edison Company	6	5	5	27	19	1	24	17	13.0	11
Ohio Power Company	28	27	28	25	26	16	17	25	24.0	28
Oklahoma Gas and Electric Company	7	13	10	11	16	16	3	5	10.1	5
PacifiCorp	24	16	16	3	6	16	4	22	13.4	12
Portland General Electric Company	19	26	15	8	17	16	26	4	16.4	20
Public Service Company of Oklahoma	10	11	14	13	15	16	10	11	12.5	10
Southern California Edison Co.	9	6	1	10	9	2	1	3	5.1	1
Virginia Electric and Power Company	5	14	11	9	7	8	27	13	11.8	8

Regional Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overal Rank
Florida Power & Light Company	**1**	**1**	**1**	**2**	**1**	**1**	**1**	**1**	**1.1**	**1**
Florida Power Corporation	2	3	2	4	4	2	2	2	2.6	2
Gulf Power Company	4	4	4	1	3	3	4	3	3.3	4
Tampa Electric Company	3	2	3	3	2	3	3	4	2.9	3

Large Utility Group	Percent Sales (MWh) Residential	Percent Sales (MWh) Other	Use per Customer	Change in Customers (%)	Change in Sales Vol (Rolling 5 Year CAGR)	Percent Generation Nuclear	Energy Losses / Total Energy Disposition	Accum. Dep./Gross Plant	Average Rank	Overal Rank
Dominion Resources, Inc.	2	3	5	4	1	1	6	6	3.5	2
DTE Energy Company	4	2	2	7	6	6	3	5	4.4	4
Entergy Corporation	5	6	7	6	7	2	2	2	4.6	5
Florida Power & Light Company	**1**	**1**	**1**	**1**	**2**	**4**	**1**	**3**	**1.8**	**1**
Progress Energy, Inc.	3	5	3	5	5	3	4	1	3.6	3
Southern Company	6	4	6	3	4	7	5	7	5.3	7
Xcel Energy, Inc.	7	7	4	2	3	5	7	4	4.9	6

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080677-EI & 090130-EI EXHIBIT 171

COMPANY Florida Power & Light Co. (FPL) (Direct)

WITNESS John J. Reed (JJR-4)

DATE 10/23/09

Productive Efficiency Rankings - 1998

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overall Rank (1 is the highest performer)
Alabama Power Company	15	19	24	15	20	5	15	10	20	21		16.4	19
Appalachian Power Company	5	21	26	9	8	10	14	13	8	7		12.1	8
Arizona Public Service Company	21	16	10	18	21	9	21	27	16	27		18.6	25
Carolina Power & Light Company	20	17	2	11	16	12	11	17	12	23		14.1	13
Cleveland Electric Illuminating Company	25	20	22	8	8	24	3	15	20	20		16.5	20
Columbus Southern Power Company	6	27	12	4	19	23	13	3	11	4		12.2	9
Dayton Power and Light Company	3	3	15	20	17	25	16	7	8	16		13.0	11
Detroit Edison Company	14	11	25	21	8	22	19	23	14	12		16.9	22
Duke Energy Carolinas, LLC	21	13	9	22	5	8	10	16	20	19		14.3	15
Duke Energy Indiana, Inc.	11	15	3	27	22	15		20	25	5		15.9	17
Entergy Arkansas, Inc.	24	7	7	24	15	11	5	6	23	16		13.8	12
Entergy Louisiana, LLC													
Florida Power & Light Company	**6**	**7**	**22**	**2**	**13**	**3**	**7**	**3**	**3**	**10**		**7.6**	**3**
Florida Power Corporation	16	12	5	1	26	4		5	10	10		9.9	6
Georgia Power Company	16	18	20	13	25	19	8	18	14	25		17.6	24
Indiana Michigan Power Company	27	1	19	14	6	13	12	24	27	18		16.1	18
Kansas City Power & Light	18	13	21	22	7	20	2	25	18	25		17.1	23
Kentucky Utilities Company	4	9	8	6	12	2	9	10	6	5		7.1	2
Nevada Power Company	6	5	1	15	13	17	6	10	4	14		9.1	5
NSTAR Electric Company	23	23	27	25	27	25	24	25	26	2		22.7	27
Ohio Edison Company	26	4	18	10	23	27	1	1	24	24		15.8	16
Ohio Power Company	19	22	14	5	8	18	23	9	16	8		14.2	14
Oklahoma Gas and Electric Company	2	5	6	17	3	6	17	13	2	9		8.0	4
PacifiCorp	6	26	15	26	17	21	25	20	18	14		18.8	26
Portland General Electric Company	12	24	17	12	4	6	18	8	7	1		10.9	7
Public Service Company of Oklahoma	1	2	3	6	1	1	4	2	1	3		2.4	1
Southern California Edison Co.	13	24	11	19	24	14	20	18	13	12		16.8	21
Virginia Electric and Power Company	10	10	12	3	2	16	22	22	4	21		12.2	9

Regional Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overal Rank
Florida Power & Light Company	**1**	**1**	**3**	**1**	**1**	**1**	**1**	**1**	**1**	**1**		**1.2**	**1**
Florida Power Corporation	2	3	1	1	4	2		1	2	1		1.9	2
Gulf Power Company	2	4	3	3	2	4	2	1	4	1		2.6	4
Tampa Electric Company	2	1	1	4	2	3	3	1	2	4		2.3	3

Large Utility Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overal Rank
Dominion Resources, Inc.	3	2	3	1	1	6	7	4	1	7		3.5	3
DTE Energy Company	4	3	7	6	2	7	6		6	5		5.1	7
Entergy Corporation	5	5	1	7	3	2	2	1	4	6		3.6	4
Florida Power & Light Company	**2**	**1**	**5**	**1**	**4**	**1**	**3**	**2**	**1**	**2**		**2.2**	**1**
Progress Energy, Inc.	7	4	1	3	6	2	1	6	5	3		3.8	5
Southern Company	5	5	6	5	6	5	4	4	7	3		5.0	6
Xcel Energy, Inc.	1	7	3	3	5	2	5	2	3	1		3.2	2

Productive Efficiency Rankings - 1999

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overall Rank (1 is the highest performer)
Alabama Power Company	19	19	15	12	18	9	18	12	14	22	25	16.6	20
Appalachian Power Company	3	4	26	15	11	7	11	17	7	6	14	11.0	9
Arizona Public Service Company	23	14	11	13	20	10	22	26	20	27	6	17.5	23
Carolina Power & Light Company	16	19	11	20	14	5	12	16	17	24	16	15.5	16
Cleveland Electric Illuminating Company	25	17	23	14	23	25		5	25	13		18.9	25
Columbus Southern Power Company	4	26	15	2	17	19	9	2	10	4	2	10.0	6
Dayton Power and Light Company	4	2	3	8	12	24	15	7	3	18	10	9.6	5
Detroit Edison Company	12	3	25	25	13	21	16	23	16	14	23	17.4	22
Duke Energy Carolinas, LLC	22	13	6	26	7	6	6	12	23	20	3	13.1	11
Duke Energy Indiana, Inc.	12	15	2	21	24	20		18	21	5	8	14.6	13
Entergy Arkansas, Inc.	24	9	19	26	9	11	3	10	24	15	21	15.5	17
Entergy Louisiana, LLC													
Florida Power & Light Company	**7**	**7**	**15**	**2**	**8**	**2**	**5**	**3**	**3**	**11**	**7**	**6.4**	**3**
Florida Power Corporation	16	16	8	1	26	4		6	11	10	5	10.3	7
Georgia Power Company	21	17	21	11	21	13	10	14	17	25	11	16.5	19
Indiana Michigan Power Company	27	1	14	21	6	8	8	25	27	19	20	16.0	18
Kansas City Power & Light	19	11	22	21	16	14		24	19	25	19	19.0	26
Kentucky Utilities Company	4	4	4	5	4	2	7	9	2	7	15	5.7	2
Nevada Power Company	9	4	1	19	5	17	4	18	3	12	1	8.5	4
NSTAR Electric Company	10	27	27	24	27	26	20	18	22	2	18	20.1	27
Ohio Edison Company	25	8	19	7	24	26	1	1	25	23	9	15.3	15
Ohio Power Company	16	22	10	6	10	16	23	11	15	8	24	14.6	14
Oklahoma Gas and Electric Company	1	9	9	17	15	22	14	8	6	8	13	11.1	10
PacifiCorp	7	23	24	15	19	23	17		13	15	22	17.8	24
Portland General Electric Company	15	23	13	9	3	14	13	14	7	1	4	10.5	8
Public Service Company of Oklahoma	1	21	5	4	2	1	2	4	1	3	17	5.5	1
Southern California Edison Co.	10	25	6	18	22	11	19	22	12	15	26	16.9	21
Virginia Electric and Power Company	14	11	18	10	1	17	21	18	9	21	12	13.8	12

Regional Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overal Rank
Florida Power & Light Company	**1**	**2**	**3**	**2**	**1**	**1**	**1**	**1**	**1**	**1**	**3**	**1.5**	**1**
Florida Power Corporation	3	4	2	1	4	2		1	2	1	2	2.2	2
Gulf Power Company	2	3	3	3	2	3	2	1	4	1	1	2.3	3
Tampa Electric Company	3	1	1	4	2	4	3	1	2	4	4	2.6	4

Large Utility Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overal Rank
Dominion Resources, Inc.	3	3	3	4	1	6	7	5	2	7	3	4.0	5
DTE Energy Company	3	1	7	6	4	7	5		6	3	7	4.9	6
Entergy Corporation	7	4	2	6	3	4	1	2	4	6	4	3.9	4
Florida Power & Light Company	**1**	**2**	**3**	**1**	**2**	**1**	**3**	**1**	**1**	**2**	**1**	**1.6**	**1**
Progress Energy, Inc.	5	4	1	3	7	2	2	6	4	3	2	3.5	2
Southern Company	6	4	6	5	6	5	4	3	7	3	5	4.9	7
Xcel Energy, Inc.	1	7	3	2	5	3	6	3	3	1	6	3.6	3

Productive Efficiency Rankings - 2000

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overall Rank (1 is the highest performer)
Alabama Power Company	18	17	22	9	20	10	21	13	16	23	23	17.5	24
Appalachian Power Company	5	11	23	14	13	11	19	10	8	6	13	12.1	11
Arizona Public Service Company	21	11	12	10	22	13	22	26	18	26	8	17.2	22
Carolina Power & Light Company	18	13	2	24	12	20	14	24	18	25	15	16.8	19
Cleveland Electric Illuminating Company	26	24	21	14	23	26		13	26	11		20.4	27
Columbus Southern Power Company	10	25	18	5	16	18	8	2	12	3	2	10.8	8
Dayton Power and Light Company	7	1	2	5	19	25	12	6	5	19	18	10.8	8
Detroit Edison Company	15	2	24	23	11	21	16	23	17	16	16	16.7	18
Duke Energy Carolinas, LLC	23	16	13	27	9	16	7	16	23	21	6	16.1	17
Duke Energy Indiana, Inc.	12	13	2	25	16	11	1	20	15	5	12	12.0	10
Entergy Arkansas, Inc.	24	9	25	26	13	22	5	6	23	20	24	17.9	25
Entergy Louisiana, LLC													
Florida Power & Light Company	**7**	**7**	**15**	**2**	**6**	**4**	**6**	**1**	**3**	**13**	**9**	**6.6**	**3**
Florida Power Corporation	16	17	8	7	25	6	3	5	13	12	4	10.5	6
Georgia Power Company	17	23	19	12	24	8	17	17	14	23	14	17.1	21
Indiana Michigan Power Company	27	4	17	21	5	1	10	25	27	15	20	15.6	15
Kansas City Power & Light	22	15	26	21	13	3		22	20	26	26	19.4	26
Kentucky Utilities Company	6	3	5	3	2	4	11	9	4	8	7	5.6	1
Nevada Power Company	4	5	1	11	4	23	9	2	2	13	1	6.8	4
NSTAR Electric Company	1	27	27	13	27	24	25	17	20	4	5	17.3	23
Ohio Edison Company	25	26	16	8	26	27	2	4	25	2	11	15.6	15
Ohio Power Company	18	22	10	16	7	13	18	10	22	9	22	15.2	14
Oklahoma Gas and Electric Company	2	6	9	18	8	17	15		6	10	17	10.8	7
PacifiCorp	9	19	19	1	18	8	20	13	8	16	19	13.6	12
Portland General Electric Company	10	21	11	16	10	7	13	10	7	1	3	9.9	5
Public Service Company of Oklahoma	3	8	6	3	3	2	4	8	1	6	21	5.9	2
Southern California Edison Co.	13	20	6	19	21	15	24	20	8	16	25	17.0	20
Virginia Electric and Power Company	14	10	14	20	1	19	23	19	8	22	10	14.5	13

Regional Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overal Rank
Florida Power & Light Company	**1**	**1**	**3**	**1**	**1**	**1**	**2**	**1**	**1**	**1**	**3**	**1.5**	**1**
Florida Power Corporation	3	4	2	2	4	2	1	1	2	1	1	2.1	2
Gulf Power Company	2	2	3	3	3	3	3	1	3	1	2	2.4	3
Tampa Electric Company	4	2	1	4	2	4	4	1	3	4	4	3.0	4

Large Utility Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overal Rank
Dominion Resources, Inc.	3	3	3	5	1	5	7	4	2	7	2	3.8	3
DTE Energy Company	4	1	7	7	4	5	5	4	5	5	4	4.6	6
Entergy Corporation	7	6	3	5	3	5	1	1	4	6	6	4.3	5
Florida Power & Light Company	**1**	**2**	**5**	**1**	**2**	**1**	**2**	**3**	**1**	**2**	**1**	**1.9**	**1**
Progress Energy, Inc.	5	4	1	4	6	4	3	6	5	3	3	4.0	4
Southern Company	5	5	6	3	6	2	6	6	7	3	5	4.9	7
Xcel Energy, Inc.	2	7	2	2	5	3	4	2	3	1	7	3.5	2

Productive Efficiency Rankings - 2001

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	**Non-Fuel Production O&M**	**Transmission O&M**	**Distribution O&M**	**A&G Expense**	**Customer Expense**	**Uncollectibles Expense**	**Days Sales Outstanding**	**Labor Efficiency**	**Total Non-Fuel O&M**	**Gross Asset Base**	**Additions to Plant / Cust Growth**	**Average Rank**	**Overall Rank** (1 is the highest performer)
Alabama Power Company	15	12	19	6	21	8	23	14	17	23	23	16.5	20
Appalachian Power Company	6	10	24	10	11	4	9	15	1	14	18	11.1	8
Arizona Public Service Company	22	11	12	8	22	16	22	23	20	27	7	17.3	24
Carolina Power & Light Company	21	17	4	20	12	11	16	21	18	26	15	16.5	20
Cleveland Electric Illuminating Company	25	18	17	20	5	21	1	8	24	5	25	15.4	16
Columbus Southern Power Company	7	23	13	4	16	22	4	2	1	3	4	9.0	4
Dayton Power and Light Company	10	1	3	2	14	26	15	6	7	16	24	11.3	9
Detroit Edison Company	15	19	21	26	19	19	19	24	26	13	14	19.5	26
Duke Energy Carolinas, LLC	23	16	8	26	10	10	14	13	26	20	9	15.9	18
Duke Energy Indiana, Inc.	9	3	5	25	2	12	3	16	12	6	19	10.2	6
Entergy Arkansas, Inc.	25	9	22	6	15	20	12	12	24	18	26	17.2	23
Entergy Louisiana, LLC													
Florida Power & Light Company	**4**	**5**	**15**	**3**	**9**	**7**	**13**	**4**	**6**	**12**	**6**	**7.6**	**3**
Florida Power Corporation	13	14	6	1	26	4	11	4	9	9	5	9.3	5
Georgia Power Company	18	21	22	15	24	17	20	16	23	22	17	19.5	26
Indiana Michigan Power Company	27	7	25	24	8	1	5	25	1	24	13	14.5	13
Kansas City Power & Light	17	13	26	18	7	1		20	18	25	21	16.6	22
Kentucky Utilities Company	5	2	2	19	2	6	8	2	8	10	10	6.7	1
Nevada Power Company	11	6	1	14	20	27	10	9	10	6	2	10.5	7
NSTAR Electric Company	2	27	27	10	27	24	26		20	3	20	18.6	25
Ohio Edison Company	24	26	11	17	2	23	2	1	22	1	3	12.0	10
Ohio Power Company	20	21	15	13	13	14	6	19	1	19	27	15.3	15
Oklahoma Gas and Electric Company	3	4	13	16	17	24	17		11	10	22	13.7	12
PacifiCorp	12	20	20	9	18	18	18	10	16	17	11	15.4	16
Portland General Electric Company	7	25	6	10	25	13	21	11	12	2	12	13.1	11
Public Service Company of Oklahoma	1	14	10	5	6	1	7	6	1	8	16	6.8	2
Southern California Edison Co.	14	24	9	20	22	15	25	18	15	14	1	16.1	19
Virginia Electric and Power Company	19	8	18	20	1	9	24	21	12	20	8	14.5	13

Regional Group	**Non-Fuel Production O&M**	**Transmission O&M**	**Distribution O&M**	**A&G Expense**	**Customer Expense**	**Uncollectibles Expense**	**Days Sales Outstanding**	**Labor Efficiency**	**Total Non-Fuel O&M**	**Gross Asset Base**	**Additions to Plant / Cust Growth**	**Average Rank**	**Overal Rank**
Florida Power & Light Company	**1**	**1**	**3**	**2**	**1**	**2**	**2**	**1**	**1**	**1**	**2**	**1.5**	**1**
Florida Power Corporation	2	4	1	1	4	1	1	1	2	1	1	1.7	2
Gulf Power Company	2	3	4	3	3	4	3	1	3	1	4	2.8	3
Tampa Electric Company	4	2	1	4	2	3	4	1	3	4	3	2.8	3

Large Utility Group	**Non-Fuel Production O&M**	**Transmission O&M**	**Distribution O&M**	**A&G Expense**	**Customer Expense**	**Uncollectibles Expense**	**Days Sales Outstanding**	**Labor Efficiency**	**Total Non-Fuel O&M**	**Gross Asset Base**	**Additions to Plant / Cust Growth**	**Average Rank**	**Overal Rank**
Dominion Resources, Inc.	7	2	4	6	1	2	7	4	2	7	2	4.0	5
DTE Energy Company	4	6	6	7	5	6	5	4	7	5	4	5.4	7
Entergy Corporation	6	5	3	3	3	6	1	1	2	5	7	3.8	4
Florida Power & Light Company	**1**	**1**	**4**	**1**	**2**	**1**	**2**	**2**	**1**	**2**	**1**	**1.6**	**1**
Progress Energy, Inc.	3	3	1	2	5	2	3		2	4	3	2.8	2
Southern Company	5	4	7	3	5	5	6	6	6	3	6	5.1	6
Xcel Energy, Inc.	2	7	2	3	4	4	4	2	5	1	5	3.5	3

Productive Efficiency Rankings - 2002

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	**Non-Fuel Production O&M**	**Transmission O&M**	**Distribution O&M**	**A&G Expense**	**Customer Expense**	**Uncollectibles Expense**	**Days Sales Outstanding**	**Labor Efficiency**	**Total Non-Fuel O&M**	**Gross Asset Base**	**Additions to Plant / Cust Growth**	**Average Rank**	**Overall Rank** (1 is the highest performer)
Alabama Power Company	16	11	21	6	21	9	15	11	15	24	23	15.6	18
Appalachian Power Company	4	4	23	13	8	8	12	8	10	9	16	10.5	7
Arizona Public Service Company	23	7	17	7	20	7	17	26	15	27	7	15.7	20
Carolina Power & Light Company	19	19	10	18	13	11	14	21	17	26	10	16.2	21
Cleveland Electric Illuminating Company	26	22	17	24	2	17	1	6	25	5	17	14.7	14
Columbus Southern Power Company	5	20	14	4	18	25	4	5	8	4	3	10.0	5
Dayton Power and Light Company	8	1	3	1	11	27	13	2	1	18	22	9.7	4
Detroit Edison Company	18	24	24	24	21	18	22	24	21	17	19	21.1	27
Duke Energy Carolinas, LLC	23	12	25	23	11	10	11	15	21	22	15	17.1	23
Duke Energy Indiana, Inc.	8	10	4	26	16	23	3	18	13	6	20	13.4	12
Entergy Arkansas, Inc.	19	7	20	27	19	15	8	11	26	20	25	17.9	24
Entergy Louisiana, LLC													
Florida Power & Light Company	**7**	**7**	**10**	**1**	**10**	**6**	**10**	**7**	**4**	**14**	**6**	**7.5**	**2**
Florida Power Corporation	11	16	7	5	26	4	9	15	8	10	5	10.5	8
Georgia Power Company	22	22	22	7	25	12	21	19	18	23	11	18.4	26
Indiana Michigan Power Company	27	2	16	22	3	1	6	25	27	15	24	15.3	16
Kansas City Power & Light	17	14	26	21	6	2		17	21	25	8	15.7	19
Kentucky Utilities Company	5	13	4	12	3	5		2	7	10	18	7.9	3
Nevada Power Company	10	6	1	11	14	26	19	14	3	10	2	10.5	8
NSTAR Electric Company	1	27	26	15	27	24	23		18	2		18.1	25
Ohio Edison Company	25	25	17	17	3	20	2	1	20	1	4	12.3	11
Ohio Power Company	19	16	12	13	14	20	7	23	24	7	26	16.5	22
Oklahoma Gas and Electric Company	2	5	6	16	9	15	16	8	6	10	21	10.4	6
PacifiCorp	13	16	9	18	16	19	18	11	14	19	13	15.1	15
Portland General Electric Company	11	25	8	7	23	22	24	8	11	3	12	14.0	13
Public Service Company of Oklahoma	2	15	12	3	6	3	5	4	1	7	14	6.5	1
Southern California Edison Co.	14	21	15	18	23	12	20	20	11	16	1	15.5	17
Virginia Electric and Power Company	15	3	1	7	1	14	25	21	5	21	9	11.1	10

Regional Group	**Non-Fuel Production O&M**	**Transmission O&M**	**Distribution O&M**	**A&G Expense**	**Customer Expense**	**Uncollectibles Expense**	**Days Sales Outstanding**	**Labor Efficiency**	**Total Non-Fuel O&M**	**Gross Asset Base**	**Additions to Plant / Cust Growth**	**Average Rank**	**Overal Rank**
Florida Power & Light Company	**1**	**1**	**3**	**1**	**1**	**2**	**2**	**1**	**1**	**1**	**2**	**1.5**	**1**
Florida Power Corporation	2	4	1	2	4	1	1	4	2	1	1	2.1	2
Gulf Power Company	3	3	4	3	2	3	3	2	3	1	3	2.7	3
Tampa Electric Company	4	2	2	4	3	4	4	2	3	4	4	3.3	4

Large Utility Group	**Non-Fuel Production O&M**	**Transmission O&M**	**Distribution O&M**	**A&G Expense**	**Customer Expense**	**Uncollectibles Expense**	**Days Sales Outstanding**	**Labor Efficiency**	**Total Non-Fuel O&M**	**Gross Asset Base**	**Additions to Plant / Cust Growth**	**Average Rank**	**Overal Rank**
Dominion Resources, Inc.	3	1	1	3	1	5	7	5	1	7	3	3.4	3
DTE Energy Company	5	7	6	6	6	7	6	3	6	5	6	5.7	7
Entergy Corporation	6	5	3	6	3	6	1	1	5	5	7	4.4	5
Florida Power & Light Company	**1**	**2**	**4**	**1**	**2**	**1**	**2**	**3**	**1**	**1**	**1**	**1.7**	**1**
Progress Energy, Inc.	4	4	4	5	5	2	3	2	4	4	2	3.5	4
Southern Company	6	3	6	3	6	3	5	6	7	3	5	4.8	6
Xcel Energy, Inc.	2	6	2	2	4	3	4		3	1	4	3.1	2

Productive Efficiency Rankings - 2003

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overall Rank (1 is the highest performer)
Alabama Power Company	16	17	21	12	21	8	13	9	19	21	19	16.0	19
Appalachian Power Company	6	4	22	5	12	8	15	4	7	6	18	9.7	5
Arizona Public Service Company	23	6	11	16	20	11	11	24	16	25	3	15.1	17
Carolina Power & Light Company	18	20	3	19	15	14	14	22	17	27	11	16.4	21
Cleveland Electric Illuminating Company	26	18	19	8	4	16	1	1	25	5	16	12.6	11
Columbus Southern Power Company	7	22	16	1	18	24	5	2	8	4	2	9.9	6
Dayton Power and Light Company	1	1	2	23	1	26	20	9	1	17	17	10.7	7
Detroit Edison Company	16	24	25	27	25	25	22	22	26	19	24	23.2	27
Duke Energy Carolinas, LLC	22	12	23	21	10	10	10	9	20	24	26	17.0	23
Duke Energy Indiana, Inc.	9	8	4	26	14	16	3	18	12	13	15	12.5	10
Entergy Arkansas, Inc.	24	8	17	19	16	16	8	16	20	20	20	16.7	22
Entergy Louisiana, LLC													
Florida Power & Light Company	**8**	**7**	**5**	**1**	**10**	**5**	**9**	**6**	**3**	**13**	**4**	**6.5**	**2**
Florida Power Corporation	12	14	9	8	22	5	12		10	13	5	11.0	9
Georgia Power Company	15	21	17	6	24	12	21	14	12	23	6	15.5	18
Indiana Michigan Power Company	27	2	14	23	3	2	6	18	27	12	23	14.3	14
Kansas City Power & Light	20	19	23	25	4	3		25	24	26	10	17.9	25
Kentucky Utilities Company	5	15	7	10	4	4		7	4	9	25	9.0	3
Nevada Power Company	10	10	1	13	19	27	16	8	4	11	1	10.9	8
NSTAR Electric Company	2	27	27	17	27	15	23		18	3	22	18.1	26
Ohio Edison Company	25	25	12	13	8	23	2	5	22	1	7	13.0	12
Ohio Power Company	21	12	13	3	13	22	7	13	22	7	27	14.5	16
Oklahoma Gas and Electric Company	4	5	5	17	9	5	17	16	4	9	9	9.1	4
PacifiCorp	14	16	20	15	16	20	18	14	14	17	14	16.2	20
Portland General Electric Company	10	25	7	6	22	21	25	9	11	2	12	13.6	13
Public Service Company of Oklahoma	3	10	10	4	4	1	4	3	2	7	21	6.3	1
Southern California Edison Co.	13	23	14	22	26	19	19	20	15	16	8	17.7	24
Virginia Electric and Power Company	18	2	26	10	2	13	24	20	9	21	13	14.4	15

Regional Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overal Rank
Florida Power & Light Company	**1**	**2**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**2**	**1.2**	**1**
Florida Power Corporation	2	4	3	3	2	1	3		2	1	3	2.4	2
Gulf Power Company	2	3	4	4	4	3	2	1	4	1	1	2.6	3
Tampa Electric Company	4	1	2	2	2	3	4	1	2	4	4	2.6	3

Large Utility Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overal Rank
Dominion Resources, Inc.	5	1	7	2	1	5	7	3	2	7	4	4.0	4
DTE Energy Company	4	7	6	7	6	7	6	6	6	5	7	6.1	7
Entergy Corporation	7	5	2	5	3	5	1	1	5	5	6	4.1	5
Florida Power & Light Company	**1**	**2**	**2**	**1**	**2**	**1**	**2**	**3**	**1**	**2**	**1**	**1.6**	**1**
Progress Energy, Inc.	3	4	1	5	5	2	3	3	3	4	2	3.2	3
Southern Company	6	3	5	2	6	2	4	6	6	3	3	4.2	6
Xcel Energy, Inc.	2	6	2	2	3	2	5	1	3	1	5	2.9	2

Productive Efficiency Rankings - 2004

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overall Rank (1 is the highest performer)
Alabama Power Company	17	16	17	16	22	9	21	15	16	23	22	17.6	23
Appalachian Power Company	6	5	23	4	12	7	15	3	8	17	26	11.5	10
Arizona Public Service Company	23	2	14	17	20	6	14	23	18	18	5	14.5	16
Carolina Power & Light Company	23	14	12	22	10	13	12	21	18	27	10	16.5	20
Cleveland Electric Illuminating Company	19	17	5	20	5	19	1	6	13	4	27	12.4	11
Columbus Southern Power Company	9	20	21	2	17	25	4	1	9	3	6	10.6	7
Dayton Power and Light Company	13	6	2	22	12	27	17	4	12	16	16	13.4	12
Detroit Edison Company	17	23	18	27	25	26	23	22	25	19	24	22.6	27
Duke Energy Carolinas, LLC	22	8	11	18	9	11	10	11	11	25	23	14.5	14
Duke Energy Indiana, Inc.	11	15	4	26	12	20	2	15	23	11	21	14.5	16
Entergy Arkansas, Inc.	25	10	12	15	18	16	9	11	18	19	15	15.3	18
Entergy Louisiana, LLC													
Florida Power & Light Company	**5**	**3**	**10**	**1**	**10**	**13**	**13**	**7**	**1**	**11**	**3**	**7.0**	**2**
Florida Power Corporation	7	10	6	7	20	7	11		6	8	2	8.4	4
Georgia Power Company	21	22	23	11	24	17	25	17	14	21	13	18.9	26
Indiana Michigan Power Company	27	1	16	24	8	2	6	18	27	11	19	14.5	14
Kansas City Power & Light	16	21	21	25	7	1		23	25	26	14	17.9	24
Kentucky Utilities Company	4	9	7	5	5	5	8		1	8	12	6.4	1
Nevada Power Company	12	6	1	13	12	21	16	9	4	14	1	9.9	6
NSTAR Electric Company	1	27	26	13	27	23	22		15	2	17	17.3	22
Ohio Edison Company	26	25	8	10	2	3	3	5	18	1	4	9.5	5
Ohio Power Company	20	13	18	8	16	23	7	8	24	6	25	15.3	18
Oklahoma Gas and Electric Company	3	10	8	19	4	15	19	10	5	10	18	11.0	8
PacifiCorp	10	18	27	12	19	10	24	13	18	24	11	16.9	21
Portland General Electric Company	7	26	15	5	23	22	26	13	9	4	7	14.3	13
Public Service Company of Oklahoma	2	19	18	3	3	4	5	2	3	6	20	7.7	3
Southern California Edison Co.	14	24	25	21	26	12	18	20	16	14	9	18.1	25
Virginia Electric and Power Company	14	3	2	9	1	18	20	19	7	22	8	11.2	9

Regional Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overal Rank
Florida Power & Light Company	**1**	**2**	**3**	**1**	**1**	**2**	**3**	**2**	**1**	**1**	**3**	**1.8**	**1**
Florida Power Corporation	2	4	1	2	3	1	2		2	1	2	2.0	2
Gulf Power Company	2	3	4	4	4	4	1	1	4	1	4	2.9	4
Tampa Electric Company	4	1	1	2	2	2	4	3	2	4	1	2.4	3

Large Utility Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overal Rank
Dominion Resources, Inc.	3	2	1	2	1	4	4	2	2	6	3	2.7	3
DTE Energy Company	4	6	5	6	5	6	6	2	5	4	6	5.0	6
Entergy Corporation	6	4	2	3	3	4	1	1	3	4	5	3.3	4
Florida Power & Light Company	**1**	**1**	**2**	**1**	**2**	**2**	**3**	**2**	**1**	**1**	**1**	**1.5**	**1**
Progress Energy, Inc.	2	2	2	4	3	1	2	5	3	3	2	2.6	2
Southern Company	5	5	5	5	5	3	5	5	5	2	4	4.5	5
Xcel Energy, Inc.													

Productive Efficiency Rankings - 2005

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overall Rank (1 is the highest performer)
Alabama Power Company	17	13	22	16	20	14	23	14	20	24	18	18.3	24
Appalachian Power Company	7	4	19	5	15	7	8	4	7	7	25	9.8	5
Arizona Public Service Company	24	9	12	10	25	6	16	25	20	26	2	15.9	21
Carolina Power & Light Company	20	9	11	23	3	9	11	23	20	25	12	15.1	17
Cleveland Electric Illuminating Company	22	21	8	11	5	19	1	5	18	2	15	11.5	9
Columbus Southern Power Company	19	18	17	2	18	24	2	2	10	4	7	11.2	8
Dayton Power and Light Company	12	20	2	7	9	24	14	6	8	17	19	12.5	11
Detroit Edison Company	15	26	24	27	22	24	20	22	26	18	21	22.3	27
Duke Energy Carolinas, LLC	22	6	13	21	8	9	10	12	11	22	14	13.5	14
Duke Energy Indiana, Inc.	13	7	3	25	11	21	5	14	17	16	23	14.1	15
Entergy Arkansas, Inc.	24	3	8	17	17	1	12	8	14	21	20	13.2	12
Entergy Louisiana, LLC													
Florida Power & Light Company	**6**	**8**	**5**	**6**	**7**	**7**	**9**	**11**	**2**	**11**	**4**	**6.9**	**1**
Florida Power Corporation	9	11	18	23	19	14	13	17	11	9	1	13.2	12
Georgia Power Company	15	22	19	14	24	18	25	17	13	18	9	17.6	23
Indiana Michigan Power Company	27	1	25	20	2	3	4	20	27	13	24	15.1	17
Kansas City Power & Light	18	13	23	26	6	5		24	25	27	22	18.9	25
Kentucky Utilities Company	4	16	7	8	4	11	15		2	8	8	8.3	3
Nevada Power Company	10	4	1	19	11	17	17	7	2	14	3	9.5	4
NSTAR Electric Company	1	27	26	17	26	24	22		20	4	26	19.3	26
Ohio Edison Company	26	23	8	2	11	23		1	19	1	5	11.9	10
Ohio Power Company	20	12	19	4	16	21	6	8	24	9	27	15.1	17
Oklahoma Gas and Electric Company	2	18	6	13	10	12	18	8	2	12	13	10.4	6
PacifiCorp	8	13	27	11	20	13	21	12	14	22	16	16.1	22
Portland General Electric Company	4	24	14	15	22	19	24	16	8	3	10	14.5	16
Public Service Company of Oklahoma	3	16	14	1	11	2	3	2	1	6	17	6.9	1
Southern California Edison Co.	11	25	16	22	26	4	7	19	14	14	11	15.4	20
Virginia Electric and Power Company	14	1	3	9	1	16	19	21	6	20	6	10.5	7

Regional Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overal Rank
Florida Power & Light Company	**1**	**2**	**1**	**1**	**1**	**1**	**2**	**2**	**1**	**1**	**3**	**1.5**	**1**
Florida Power Corporation	3	4	3	3	3	3	3	2	3	1	2	2.7	4
Gulf Power Company	2	3	3	3	4	1	1	1	4	1	4	2.5	2
Tampa Electric Company	3	1	1	2	2	4	4	4	2	4	1	2.5	3

Large Utility Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overal Rank
Dominion Resources, Inc.	3	1	1	2	1	5	4	4	1	6	3	2.8	2
DTE Energy Company	6	7	6	7	6	7	5	7	7	5	5	6.2	7
Entergy Corporation	7	4	3	4	4	3	2	1	4	7	6	4.1	5
Florida Power & Light Company	**1**	**2**	**2**	**1**	**2**	**1**	**1**	**1**	**1**	**2**	**1**	**1.4**	**1**
Progress Energy, Inc.	3	2	5	6	3	2	3	5	5	3	2	3.5	4
Southern Company	3	5	6	5	6	4	6	5	6	4	4	4.9	6
Xcel Energy, Inc.	2	6	4	3	5	6		1	3	1		3.4	3

Productive Efficiency Rankings - 2006

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	**Non-Fuel Production O&M**	**Transmission O&M**	**Distribution O&M**	**A&G Expense**	**Customer Expense**	**Uncollectibles Expense**	**Days Sales Outstanding**	**Labor Efficiency**	**Total Non-Fuel O&M**	**Gross Asset Base**	**Additions to Plant / Cust Growth**	**Average Rank**	**Overall Rank (1 is the highest performer)**
Alabama Power Company	17	18	24	17	21	12	19	16	20	22	20	18.7	27
Appalachian Power Company	11	4	19	5	7	5	10	5	8	7	25	9.6	5
Arizona Public Service Company	27	9	15	17	23	7	16	24	21	28	3	17.3	22
Carolina Power & Light Company	24	9	9	21	3	10	12	20	18	26	9	14.6	13
Cleveland Electric Illuminating Company	2	19	9	2	8	21	1	2	1	2	11	7.1	1
Columbus Southern Power Company	13	22	13	3	18	23	2	3	9	3	4	10.3	8
Dayton Power and Light Company	8	21	4	10	15	28	13	7	13	19	24	14.7	15
Detroit Edison Company	20	26	25	26	26	27	23	22	27	18	22	23.8	28
Duke Energy Carolinas, LLC	18	2	13	25	5	6	14		17	24	14	13.8	12
Duke Energy Indiana, Inc.	21	17	5	28	14	25	5		25	21	21	18.2	26
Entergy Arkansas, Inc.	24	11	6	23	19	20	8	8	22	16	16	15.7	18
Entergy Louisiana, LLC	23	12	3	20	13	12		13	11	25		14.7	14
Florida Power & Light Company	**6**	**8**	**9**	**5**	**15**	**7**	**9**	**5**	**6**	**8**	**6**	**7.6**	**2**
Florida Power Corporation	6	14	18	8	20	16	11	12	7	11	7	11.8	10
Georgia Power Company	13	23	22	12	23	18	25	17	15	16	1	16.8	21
Indiana Michigan Power Company	28	1	22	22	3	2	4	21	28	11	26	15.3	17
Kansas City Power & Light	16	19	17	26	2	3		23	22	27	23	17.8	24
Kentucky Utilities Company	5	3	8	9	5	9	17		3	8	19	8.6	3
Nevada Power Company	9	4	1	16	11	21	15	9	3	14	5	9.8	6
NSTAR Electric Company	1	28	27	15	27	19	22		22	5	13	17.9	25
Ohio Edison Company	21	27	9	1	12	26		1	14	1	2	11.4	9
Ohio Power Company	26	15	16	7	15	23	3	9	26	13	27	16.4	20
Oklahoma Gas and Electric Company	3	6	2	17	10	14	20	11	2	8	17	10.0	7
PacifiCorp	12	16	28	10	23	17	21	14	16	22	15	17.6	23
Portland General Electric Company	9	24	19	13	22	14	24	15	12	3	12	15.2	16
Public Service Company of Oklahoma	4	13	26	4	9	1	6	4	5	6	18	8.7	4
Southern California Edison Co.	13	24	19	24	27	4	7	18	18	14	10	16.2	19
Virginia Electric and Power Company	18	7	7	13	1	11	18	18	9	20	8	11.8	10

Regional Group	**Non-Fuel Production O&M**	**Transmission O&M**	**Distribution O&M**	**A&G Expense**	**Customer Expense**	**Uncollectibles Expense**	**Days Sales Outstanding**	**Labor Efficiency**	**Total Non-Fuel O&M**	**Gross Asset Base**	**Additions to Plant / Cust Growth**	**Average Rank**	**Overal Rank**
Florida Power & Light Company	**1**	**1**	**1**	**1**	**1**	**1**	**2**	**1**	**1**	**1**	**2**	**1.2**	**1**
Florida Power Corporation	1	4	3	2	3	4	3	3	2	1	3	2.6	3
Gulf Power Company	3	2	3	4	4	2	1	3	4	1	1	2.5	2
Tampa Electric Company	4	2	1	3	2	3	4	2	3	4	4	2.9	4

Large Utility Group	**Non-Fuel Production O&M**	**Transmission O&M**	**Distribution O&M**	**A&G Expense**	**Customer Expense**	**Uncollectibles Expense**	**Days Sales Outstanding**	**Labor Efficiency**	**Total Non-Fuel O&M**	**Gross Asset Base**	**Additions to Plant / Cust Growth**	**Average Rank**	**Overal Rank**
Dominion Resources, Inc.	5	1	3	2	1	2	4	3	1	7	2	2.8	2
DTE Energy Company	5	7	6	6	6	7	5	7	6	4	5	5.8	7
Entergy Corporation	7	3	1	6	4	5	1	2	3	6		3.8	5
Florida Power & Light Company	**1**	**2**	**4**	**1**	**2**	**1**	**2**	**3**	**1**	**2**	**1**	**1.8**	**1**
Progress Energy, Inc.	3	4	5	4	2	2	3	3	3	4	3	3.3	3
Southern Company	4	5	6	4	6	4	6	6	6	3	4	4.9	6
Xcel Energy, Inc.	2	6	2	2	5	6	7	1	3	1		3.5	4

Productive Efficiency Rankings - 2007

(a rank of 1 indicates the most challenged performer for each metric)

Straight Electric Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overall Rank (1 is the highest performer)
Alabama Power Company	19	17	24	17	22	15	23	16	20	23	18	19.5	27
Appalachian Power Company	10	3	17	6	11	15	10	4	7	7	20	10.0	7
Arizona Public Service Company	27	14	19	13	22	8	18	23	22	27	5	18.0	26
Carolina Power & Light Company	26	11	12	19	3	10	8	22	22	26	7	15.1	17
Cleveland Electric Illuminating Company	2	21	11	2	8	22		3	1	2		8.0	2
Columbus Southern Power Company	18	14	16	3	17	21	1	2	5	3	3	9.4	4
Dayton Power and Light Company	12	23	3	12	13	27	14	5	18	20	23	15.5	19
Detroit Edison Company	16	26	26	28	26	27	24	15	27	12	25	22.9	28
Duke Energy Carolinas, LLC	22	3	7	24	3	8	15		15	25	9	13.1	10
Duke Energy Indiana, Inc.	13	11	2	26	18	25	2		22	18	19	15.6	21
Entergy Arkansas, Inc.	23	16	9	22	19	18	6	11	21	15	15	15.9	22
Entergy Louisiana, LLC	21	13	5	20	16	22	5	11	11	22		14.6	14
Florida Power & Light Company	**4**	**7**	**7**	**3**	**13**	**5**	**13**	**7**	**2**	**9**	**4**	**6.7**	**1**
Florida Power Corporation	8	9	23	21	20	17	11	14	11	12	16	14.7	15
Georgia Power Company	17	21	21	14	22	12	25	16	17	18	2	16.8	23
Indiana Michigan Power Company	28	3	22	22	5	1	4	19	28	10	24	15.1	17
Kansas City Power & Light	13	20	13	26	2	2		24	25	27	21	17.3	25
Kentucky Utilities Company	6	6	6	7	6	4	16		2	11	22	8.6	3
Nevada Power Company	7	2	1	16	8	19	12	8	4	20	6	9.4	4
NSTAR Electric Company	1	27	26	11	27	22	22		15	3	1	15.5	20
Ohio Edison Company	19	27	13	1	13	25		1	8	1	10	11.8	9
Ohio Power Company	23	1	13	9	12	20	3	10	26	14	26	14.3	12
Oklahoma Gas and Electric Company	11	8	4	10	7	11	17	11	5	8	12	9.5	6
PacifiCorp	9	18	25	5	21	6	21	9	14	23	14	15.0	16
Portland General Electric Company	3	24	17	17	22	14	20	16	10	5	11	14.5	13
Public Service Company of Oklahoma	4	19	28	8	8	3	7	5	11	6	17	10.5	8
Southern California Edison Co.	13	24	19	25	28	7	9	19	19	16	8	17.0	24
Virginia Electric and Power Company	23	10	10	15	1	13	19	21	8	17	13	13.6	11

Regional Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overal Rank
Florida Power & Light Company	**1**	**1**	**1**	**1**	**1**	**1**	**3**	**1**	**1**	**1**	**2**	**1.3**	**1**
Florida Power Corporation	2	4	3	3	3	4	2	3	3	3	4	3.1	4
Gulf Power Company	2	2	3	4	4	2	1	1	4	1	1	2.3	2
Tampa Electric Company	4	2	1	2	2	2	4	3	2	4	3	2.6	3

Large Utility Group	Non-Fuel Production O&M	Transmission O&M	Distribution O&M	A&G Expense	Customer Expense	Uncollectibles Expense	Days Sales Outstanding	Labor Efficiency	Total Non-Fuel O&M	Gross Asset Base	Additions to Plant / Cust Growth	Average Rank	Overal Rank
Dominion Resources, Inc.	6	3	4	3	1	2	4	4	2	5	3	3.4	3
DTE Energy Company	4	7	6	7	6	7	7	4	7	3	5	5.7	7
Entergy Corporation	6	4	1	6	4	6	1	1	4	3		3.6	5
Florida Power & Light Company	**1**	**1**	**2**	**1**	**2**	**1**	**3**	**3**	**1**	**2**	**1**	**1.6**	**1**
Progress Energy, Inc.	3	2	5	5	2	2	2	4	5	7	2	3.5	4
Southern Company	5	5	6	4	6	2	5	4	6	5	4	4.7	6
Xcel Energy, Inc.	2	6	2	2	5	5	6	1	3	1		3.3	2

Operational Metrics

Metric	2002	2003	2004	2005	2006	2007	Average
			FPL Values by Year				
Fossil Plant Performance							
Fossil Equivalent Availability Factor	93.80	90.10	93.70	91.70	92.20	92.60	92.35
Fossil Equivalent Forced Outage Rate	2.39	3.02	1.08	2.55	3.02	2.27	2.39
Source: North American Reliability Council (NERC)							
Nuclear Performance							
Nuclear Capacity Factor: Regulated Plants		89.801	87.884	81.715	89.577	83.506	86.497
Nuclear Forced Loss Rate: Regulated Plants		1.783	2.223	4.693	3.050	1.720	2.694
Nuclear Industrial Safety Accident Rate (ISA): Regulated Plants		0.140	0.225	0.125	0.080	0.040	0.122
Source: SNL Financial, Institute of Nuclear Power Operations (INPO)							
Distribution System Reliability							
System Average Interruption Frequency Index (SAIFI) excluding Major Events		1.35	1.22	1.15	1.29		1.25
Customer Average Interruption Duration Index (CAIDI) excluding Major Events		50.50	57.30	60.40	57.80		56.50
System Average Interruption Duration Index (SAIDI) excluding Major Events		68.20	69.70	69.60	74.30		70.45
Source: Edison Electric Institute (EEI)							
Customer Service							
Care Center Cost per Customer		$6.99	$7.93	$7.00	$8.08	$7.96	$7.59
Abandonment Rate		2.0%	4.0%	3.0%	3.1%	1.1%	2.6%
Average Speed of Answer (seconds)		29	49	41	33	27	36
Source: FPL report from PA Consulting Group							

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 172
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS John J. Reed (JJR-5)
DATE 10/23/09

Operational Metrics

Metric	FPL Rank of Total Ranked						
	2002	2003	2004	2005	2006	2007	Average Rank
Fossil Plant Performance							
Fossil Equivalent Availability Factor	1 of 37	7 of 37	1 of 37	5 of 37	8 of 36	4 of 36	4 of 37
Fossil Equivalent Forced Outage Rate	3 of 37	8 of 37	2 of 37	4 of 37	7 of 36	6 of 36	5 of 37
Nuclear Performance							
Nuclear Capacity Factor: Regulated Plants		8 of 21	14 of 21	16 of 21	10 of 21	19 of 21	13 of 21
Nuclear Forced Loss Rate: Regulated Plants		9 of 21	12 of 21	17 of 21	15 of 21	13 of 21	13 of 21
Nuclear Industrial Safety Accident Rate (ISA): Regulated Plants		10 of 21	13 of 21	9 of 21	8 of 21	6 of 21	9 of 21
Distribution System Reliability							
System Average Interruption Frequency Index (SAIFI) excluding Major Events		42 of 63	48 of 76	30 of 66	50 of 69		43 of 69
Customer Average Interruption Duration Index (CAIDI) excluding Major Events		3 of 63	5 of 76	3 of 66	8 of 70		5 of 69
System Average Interruption Duration Index (SAIDI) excluding Major Events		12 of 63	19 of 76	9 of 66	19 of 70		15 of 69
Customer Service							
Care Center Cost per Customer		1st Quartile	2nd Quartile	1st Quartile	2nd Quartile	1st Quartile	1st Quartile
Abandonment Rate		1st Quartile	2nd Quartile	1st Quartile	2nd Quartile	1st Quartile	1st Quartile
Average Speed of Answer (seconds)		1st Quartile	3rd Quartile	2nd Quartile	2nd Quartile	1st Quartile	2nd Quartile

Benchmarking Workpapers

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 173
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS John J. Reed (JJR-6)
DATE 10/23/09

Benchmarking Workpapers

Comparable Groups

	Straight Electric	Regional	Large Utilities
Alabama Power Company	√		
Appalachian Power Company	√		
Arizona Public Service Company	√		
Carolina Power & Light Company	√		
Cleveland Electric Illuminating Company	√		
Columbus Southern Power Company	√		
Dayton Power and Light Company	√		
Detroit Edison Company	√		
Dominion Resources, Inc.			√
DTE Energy Company			√
Duke Energy Carolinas, LLC	√		
Duke Energy Indiana, Inc.	√		
Entergy Arkansas, Inc.	√		
Entergy Corporation			√
Entergy Louisiana, LLC	√		
Florida Power Corporation	√	√	
Georgia Power Company	√		
Gulf Power Company		√	
Indiana Michigan Power Company	√		
Kansas City Power & Light	√		
Kentucky Utilities Company	√		
Nevada Power Company	√		
NSTAR Electric Company	√		
Ohio Edison Company	√		
Ohio Power Company	√		
Oklahoma Gas and Electric Company	√		
PacifiCorp	√		
Portland General Electric Company	√		
Progress Energy, Inc.			√
Public Service Company of Oklahoma	√		
Southern California Edison Co.	√		
Southern Company			√
Tampa Electric Company		√	
Virginia Electric and Power Company	√		
Xcel Energy, Inc.			√
# In Group	27	3	6

Benchmarking Workpapers

Definitions

Situational Assessment

Metric	Units	Calculation
Percent Sales (MWh) Residential	percent (%)	Total Residential MWh Sold/Total MWh Sold
Percent Sales (MWh) Other	percent (%)	(Total Public Street and Highway Lighting + Total Sales to Public Authorities + Total Sales to Railroads + Total Interdepartmental Sales + Total Sales for Resale in MWh Sold) / Total MWh Sold
Use per Customer	MWh/customer	Total Sales of Electricity / Total Customers
Change in Customers (%)	percent (%)	(Total Customers for Current Year - Total Customers for Previous Year) / Total Customers for Previous Year
Change in Sales (5-year CAGR)	CAGR (%)	Total MWh Sold to Ultimate Consumers for Current Year / Total MWh Sold to Ultimate Consumers for 5 Years Prior to Current Year)$^{1/5}$ -1
Percent Generation Nuclear	percent (%)	Total Nuclear MWh Produced / Net Generation
Energy Losses / Total Energy Disposition	percent (%)	Total MWh of Energy Lost / Total Disposition of Energy (MWh)
Accum. Dep./Gross Plant	$000s accum dep/$ gross plant	Accumulated Depreciation for Total Electric Plant / Total Electric Utility Plant

Productive Efficiency

Metric Group	Metric	Units	Calculation
Non-Fuel Production O&M	Non-Fuel Production O&M per Customer	$/customer	Total Power Production O&M Expenses less Fuel, Purchased Power, and Other Expenses / Total Customers
	Non-Fuel Production O&M MWh Produced	$/MWh	Total Power Production O&M Expenses less Fuel, Purchased Power, and Other Expenses / Total MWh Produced
Transmission O&M	Transmission O&M per Customer	$/customer	Total Transmission O&M Expenses / Total Customers
	Transmission O&M per MWh	$/kWh	Total Transmission O&M Expenses / Total MWh Sold
	Transmission O&M per Mile of Transmission Line	$000s/mile	Total Transmission O&M Expense less Transmission of Electricity by Others / Total Length (Miles) of Transmission Line
Distribution O&M	Distribution O&M per Customer	$/customer	Total Distribution O&M Expenses / Total Ultimate Customers
	Distribution O&M per MWh	$/MWh	Total Distribution O&M Expenses / Total MWh Sold to Ultimate Customers
A&G Expense	A&G Expense per Customer	$/customer	Total A&G Expenses / Total Ultimate Customers
	A&G Expense per MWh	$/MWh	Total A&G Expenses / Total MWh Sold to Ultimate Customers
Customer Expense	Customer Expense per Customer	$/customer	(Total Customer Accounts Expenses + Total Customer Service and Informational Expenses + Total Sales Expenses) / Total Ultimate Customers
	Customer Expense per MWh	$/MWh	(Total Customer Accounts Expenses + Total Customer Service and Informational Expenses + Total Sales Expenses) / Total MWh Sold to Ultimate Customers
Uncollectibles Expense	Uncollectibles Expense per Customer	$/customer	Uncollectible Accounts Expenses / Total Ultimate Customers
	Uncollectibles Expense per MWh	$/kWh	Uncollectible Accounts Expenses / Total MWh Sold to Ultimate Customers
Days Sales Outstanding	Days Sales Outstanding	days sales outstanding	365 / (Total Sales of Electricity / Average of Customer Accounts Receivable for Current Year and Previous Year)
Labor Efficiency	Employees per Thousand Customers	employees/ thousand customer	Total Employees / (Total Customers /1000))
	Salaries, Wages, Pensions, and Benefits per Employee	$000s/employee	(Total Electric Salaries and Wages + Total Pensions and Benefits) / Total Employees
Total Non-Fuel O&M	Total Non-Fuel O&M per Customer	$/customer	Total O&M Expenses less Fuel, Purchased Power, and Other / Total Ultimate Customers
	Total Non-Fuel O&M per MWh Sold	$/MWh	Total O&M Expenses less Fuel, Purchased Power, and Other / Total MWh Sold to Ultimate Customers

Benchmarking Workpapers

Definitions

Productive Efficiency (continued)

Metric Group	Metric	Units	Calculation
Gross Asset Base	Gross Asset Base per Customer	$000s/customer	Total Electric Utility Plant / Total Customers
	Gross Asset Base per kWh	$000s/kWh	Total Electric Utility Plant / Total MWh Sold
Additions to Plant / Cust Growth	Additions to Plant / Cust Growth	$000s/change in customers	Gross Additions to Utility Plant (less nuclear fuel) / Total New Customers (change in 2 year rolling average number of customers)

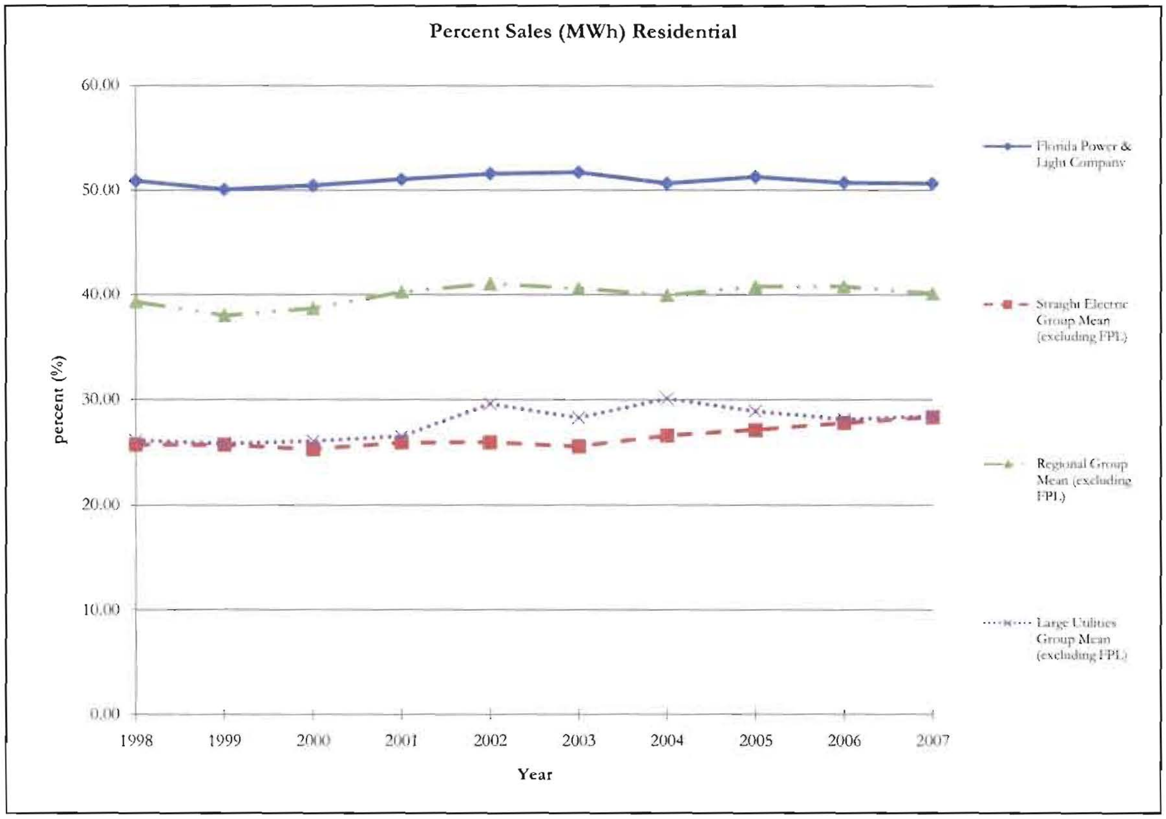
Operational Metrics

Metric Group	Metric	Units	Calculation
Fossil Plant Performance	Fossil Equivalent Availability Factor	percent (%)	Weighted Equivalent Availability Factor (excluding Maintenance Outage Factor)
	Fossil Equivalent Forced Outage Rate	percent (%)	Weighted Equivalent Forced Outage Rate
Nuclear Plant Performance	Nuclear Capacity Factor	percent (%)	Percentage of energy generated relative to capacity
	Nuclear Forced Loss Rate	percent (%)	Percentage of energy generation during non-outage periods that a plant is not capable of supplying to the electrical grid because of unplanned energy losses
	Nuclear Industrial Safety Accident Rate	Accidents/ 200,000 workhours	Number of accidents that result in lost work time, restricted work, or fatalities per 200,000 workhours.
System Reliability	System Average Interruption Frequency Index (SAIFI) for All Interruptions	percent (%)	Total Number of Customers Interrupted / Total Number of Customers Served
	Customer Average Interruption Duration Index (CAIDI) for All Interruptions	percent (%)	Sum of All Customer Interruption Durations / Total Number of Customer Interruptions
	System Average Interruption Duration Index (SAIDI) for All Interruptions	percent (%)	Sum of All Customer Interruption Durations / Total Number of Customer Served

Benchmarking Workpapers
Situational Assessment

Benchmarking Workpapers

Situational Assessment



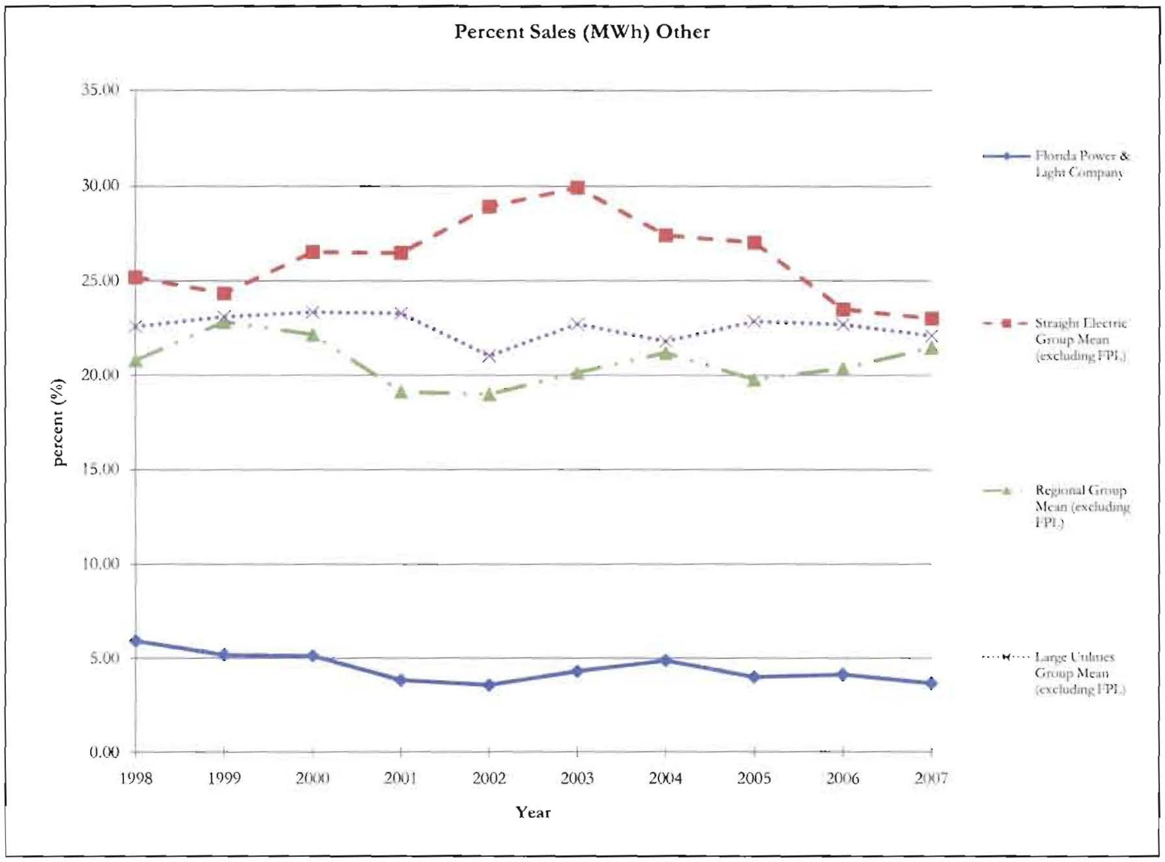
Percent Sales (MWh) Residential

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	50.90	50.08	50.46	51.06	51.61	51.75	50.69	51.29	50.75	50.67
Straight Electric Group Mean (excluding FPL)	25.74	25.73	25.32	25.93	25.95	25.59	26.61	27.13	27.82	28.36
Regional Group Mean (excluding FPL)	39.31	38.00	38.67	40.26	41.05	40.61	39.95	40.78	40.79	40.13
Large Utilities Group Mean (excluding FPL)	26.13	25.83	26.08	26.52	29.62	28.28	30.12	28.91	28.15	28.46
Rankings										
	1998	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	1	1	1
Total Ranked	27	27	27	23	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	1	1	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	1	1	1
Total Ranked	7	7	7	7	6	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Total Residential MWh Sold; Total MWh Sold

Benchmarking Workpapers

Situational Assessment

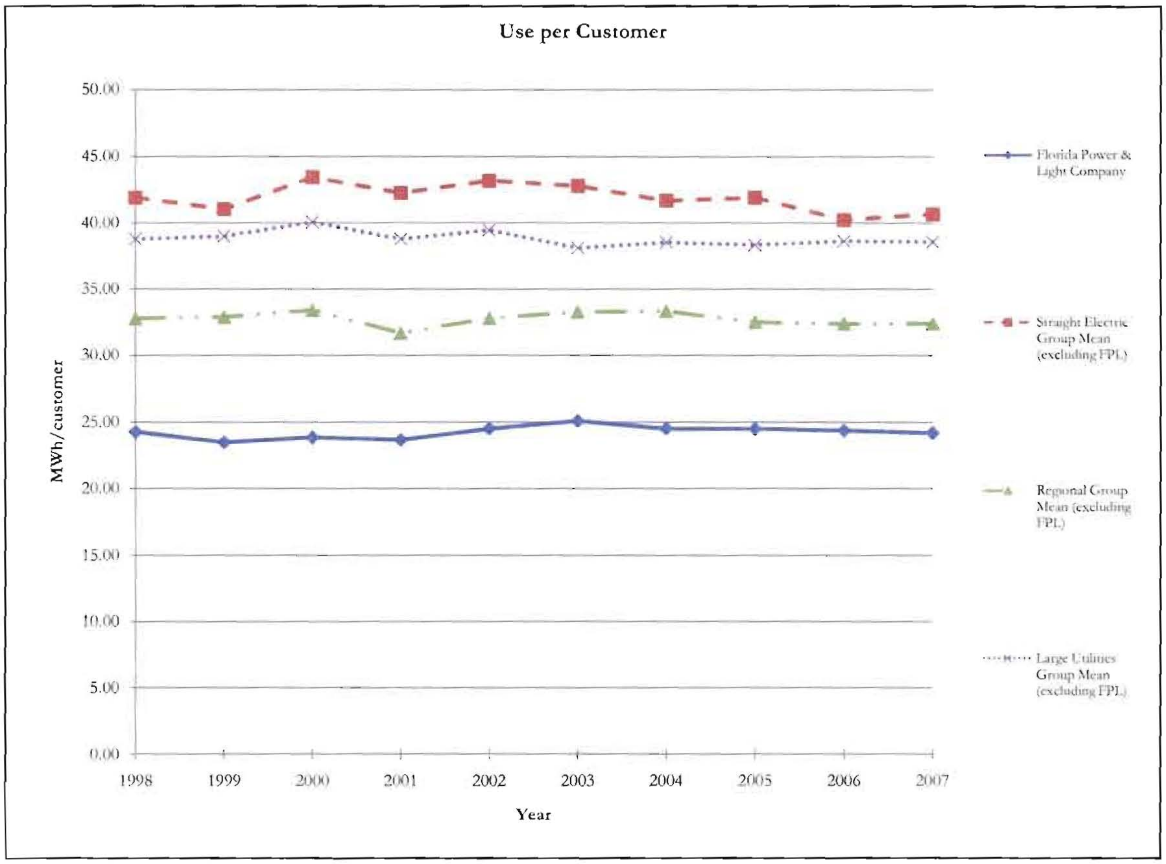


Percent Sales (MWh) Other

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	5.93	5.19	5.13	3.82	3.56	4.30	4.87	3.99	4.12	3.66
Straight Electric Group Mean (excluding FPL)	25.19	24.32	26.53	26.47	28.92	29.92	27.41	27.03	23.48	23.00
Regional Group Mean (excluding FPL)	20.79	22.82	22.16	19.13	19.00	20.14	21.19	19.78	20.38	21.49
Large Utilities Group Mean (excluding FPL)	22.56	23.09	23.33	23.26	21.02	22.70	21.78	22.84	22.67	22.08
Rankings										
	1998	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	2	2	2	2	2	1	2	1	1	1
Total Ranked	27	27	27	23	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	1	1	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	1	1	1
Total Ranked	7	7	7	7	6	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Total Public Street and Highway Lighting, Total Sales to Public Authorities, Total Sales to Railroads, Total Interdepartmental Sales, Total Sales for Resale in MWh Sold; Total MWh Sold

Benchmarking Workpapers
Situational Assessment



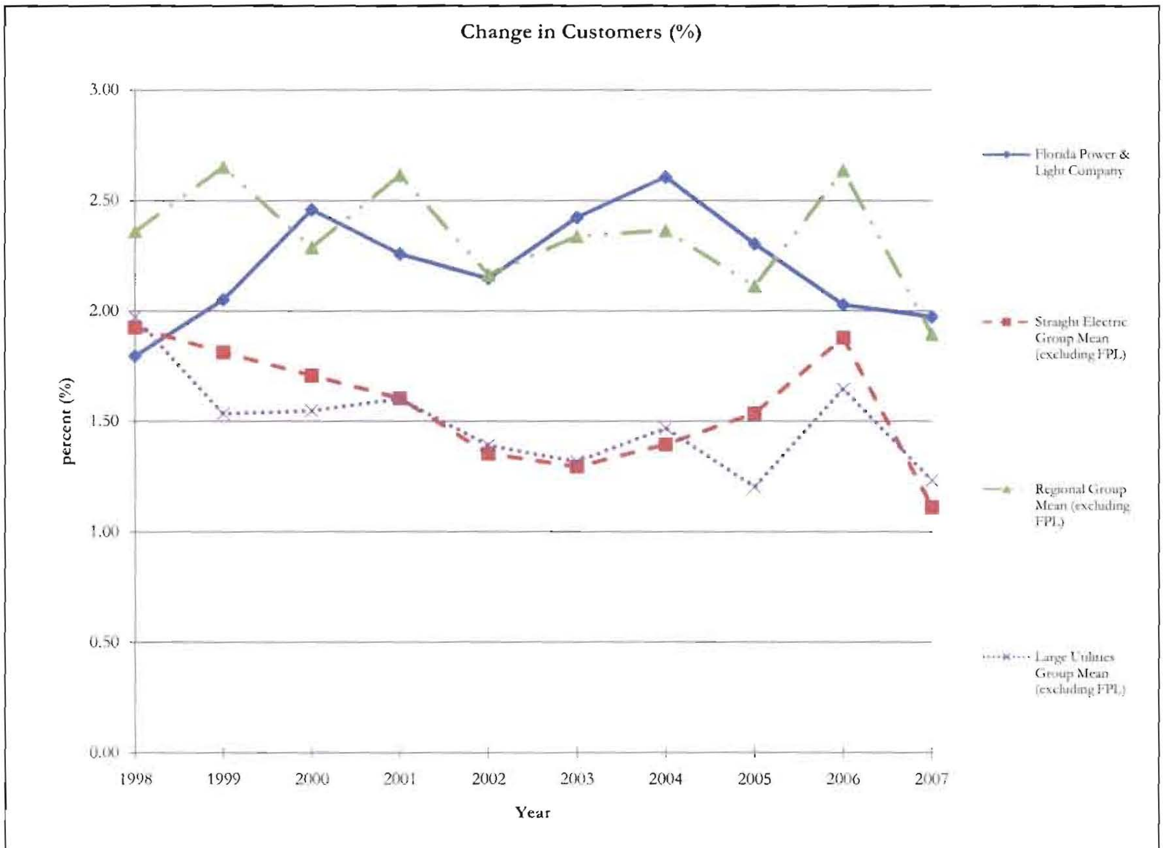
Use per Customer

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	24.28	23.49	23.85	23.68	24.52	25.10	24.52	24.52	24.39	24.20
Straight Electric Group Mean (excluding FPL)	41.90	41.03	43.44	42.25	43.17	42.79	41.68	41.91	40.23	40.68
Regional Group Mean (excluding FPL)	32.79	32.91	33.41	31.69	32.80	33.30	33.35	32.51	32.39	32.42
Large Utilities Group Mean (excluding FPL)	38.79	39.00	40.07	38.78	39.47	38.11	38.53	38.33	38.62	38.59
Rankings										
	1998	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	2	3	3	3	2	3	3	3	3	3
Total Ranked	27	27	27	23	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	1	1	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	1	1	1	1	1	2	2	2	1	1
Total Ranked	7	7	7	7	6	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Total Sales of Electricity; Total Customers

Benchmarking Workpapers

Situational Assessment

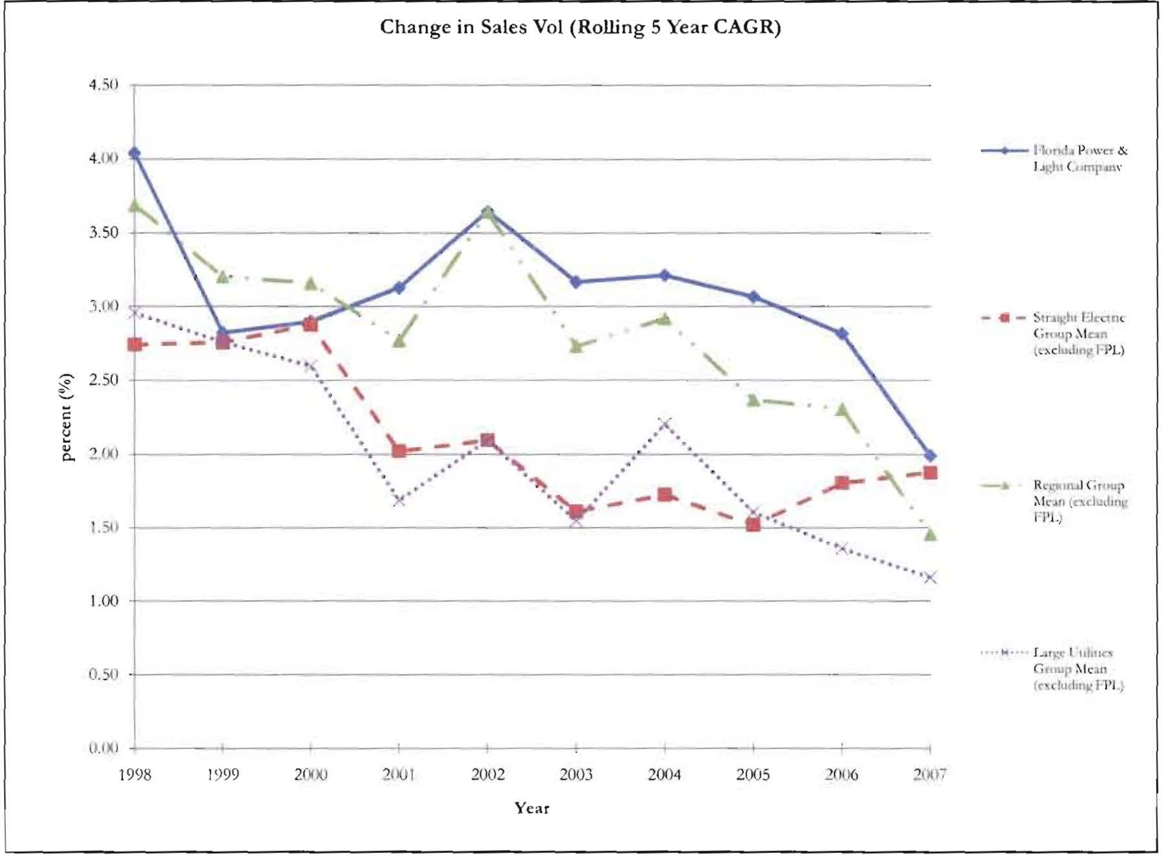


Change in Customers (%)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	1.80	2.05	2.46	2.26	2.15	2.42	2.61	2.30	2.03	1.97
Straight Electric Group Mean (excluding FPL)	1.93	1.81	1.71	1.60	1.35	1.29	1.39	1.54	1.88	1.11
Regional Group Mean (excluding FPL)	2.36	2.65	2.29	2.61	2.17	2.34	2.37	2.11	2.64	1.89
Large Utilities Group Mean (excluding FPL)	1.97	1.53	1.55	1.60	1.39	1.32	1.47	1.20	1.65	1.23
Rankings	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Straight Electric Group:										
Florida Power & Light Company Rank	12	12	5	7	4	3	3	3	8	6
Total Ranked	27	27	27	27	27	27	27	27	27	27
Regional Group:										
Florida Power & Light Company Rank	4	4	2	3	2	2	1	2	4	2
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	4	2	1	2	2	1	1	1	3	1
Total Ranked	7	7	7	7	7	7	6	6	7	7

Source: SNL Interactive, FERC Form 1
Total Customers for Current Year and Previous Year

Benchmarking Workpapers
Situational Assessment



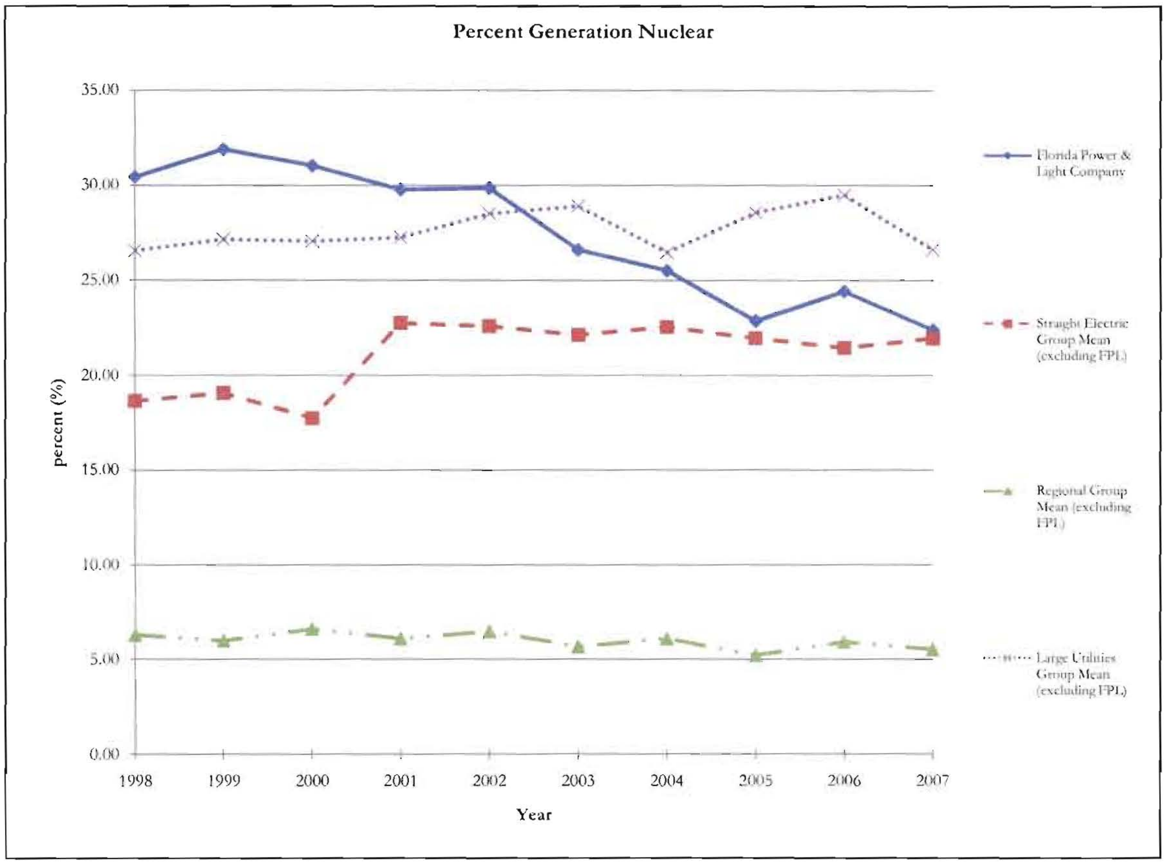
Change in Sales Vol (Rolling 5 Year CAGR)

Annual Values	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Florida Power & Light Company	4.04	2.82	2.90	3.13	3.65	3.17	3.21	3.07	2.82	1.99
Straight Electric Group Mean (excluding FPL)	2.74	2.76	2.88	2.02	2.10	1.61	1.73	1.52	1.80	1.88
Regional Group Mean (excluding FPL)	3.69	3.21	3.16	2.77	3.64	2.73	2.92	2.37	2.31	1.46
Large Utilities Group Mean (excluding FPL)	2.96	2.76	2.60	1.69	2.10	1.55	2.20	1.60	1.36	1.16
Rankings	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Straight Electric Group:										
Florida Power & Light Company Rank	4	14	13	5	2	4	4	3	6	11
Total Ranked	27	27	27	27	27	27	27	27	27	26
Regional Group:										
Florida Power & Light Company Rank	2	3	3	1	2	1	1	1	1	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	1	4	3	1	1	1	2	1	1	2
Total Ranked	7	7	7	7	7	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Total MWh Sold to Ultimate Consumers for Current Year and 5 Years preceding

Benchmarking Workpapers

Situational Assessment



Percent Generation Nuclear

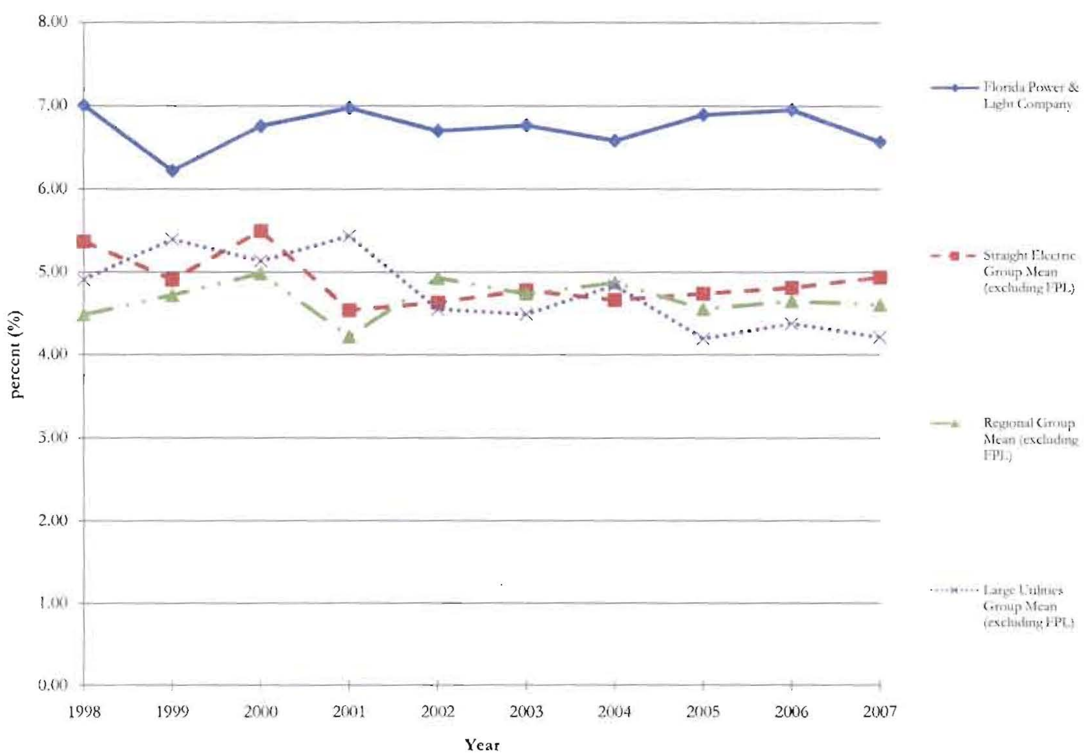
	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	30.44	31.91	31.04	29.78	29.86	26.61	25.51	22.88	24.43	22.40
Straight Electric Group Mean (excluding FPL)	18.67	19.09	17.75	22.76	22.60	22.14	22.56	21.96	21.45	21.95
Regional Group Mean (excluding FPL)	6.30	5.98	6.61	6.11	6.48	5.67	6.10	5.22	5.92	5.54
Large Utilities Group Mean (excluding FPL)	26.55	27.17	27.07	27.26	28.51	28.91	26.46	28.57	29.50	26.60
Rankings										
	1998	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	9	9	8	10	10	10	10	10	10	11
Total Ranked	28	28	28	28	28	28	28	28	28	28
Regional Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	1	1	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	4	4	4	4	4	4	4	4	4	4
Total Ranked	7	7	7	7	7	7	7	7	7	7

Source: SNL Interactive, FERC Form 1
Total Nuclear MWh Produced; Net Generation

Benchmarking Workpapers

Situational Assessment

Energy Losses / Total Energy Disposition



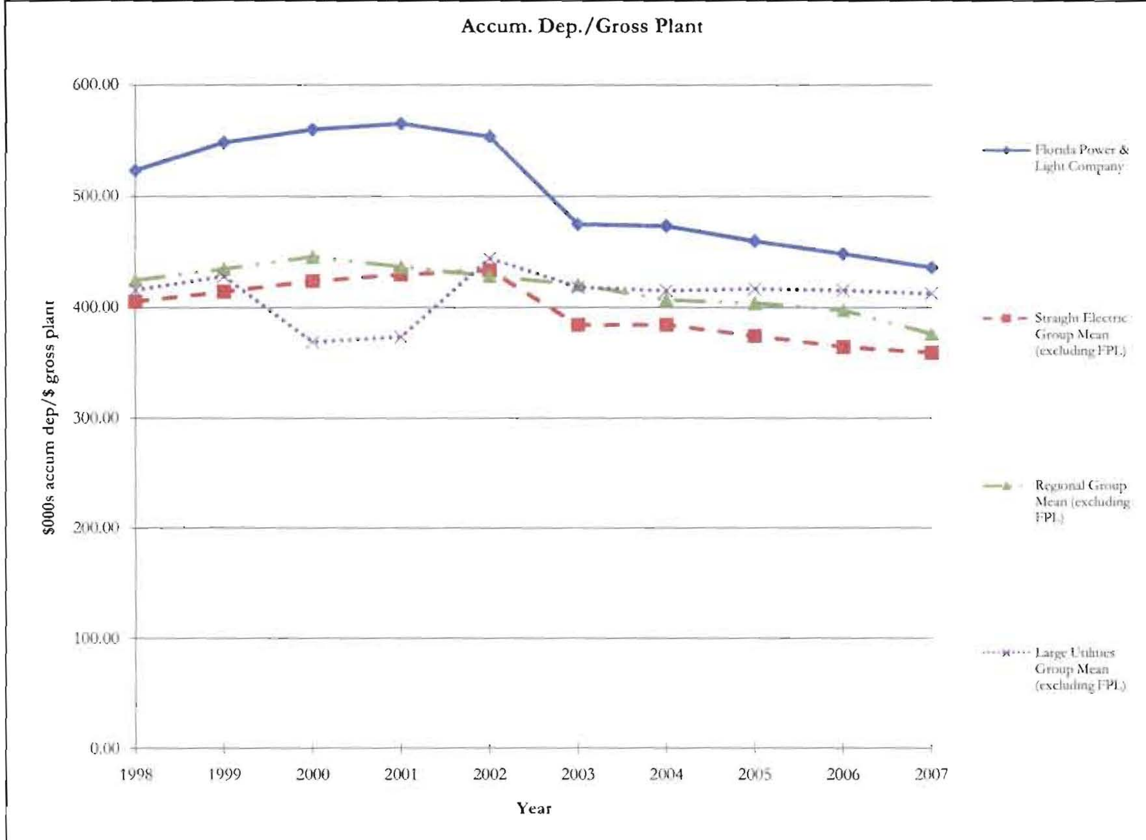
Energy Losses / Total Energy Disposition

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	7.00	6.22	6.76	6.97	6.70	6.77	6.58	6.89	6.95	6.57
Straight Electric Group Mean (excluding FPL)	5.37	4.91	5.49	4.54	4.63	4.78	4.66	4.74	4.81	4.94
Regional Group Mean (excluding FPL)	4.48	4.72	4.98	4.22	4.93	4.74	4.87	4.55	4.65	4.60
Large Utilities Group Mean (excluding FPL)	4.91	5.39	5.13	5.43	4.55	4.49	4.84	4.20	4.38	4.22
Rankings	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	3	6	4	4	4	3	3	2	1	2
Total Ranked	27	27	27	27	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	1	1	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	1	2	1	2	1	1	1	1	1	1
Total Ranked	7	7	7	7	7	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Total MWh of Energy Lost; Total Disposition of Energy (MWh)

Benchmarking Workpapers

Situational Assessment



Accum. Dep./Gross Plant

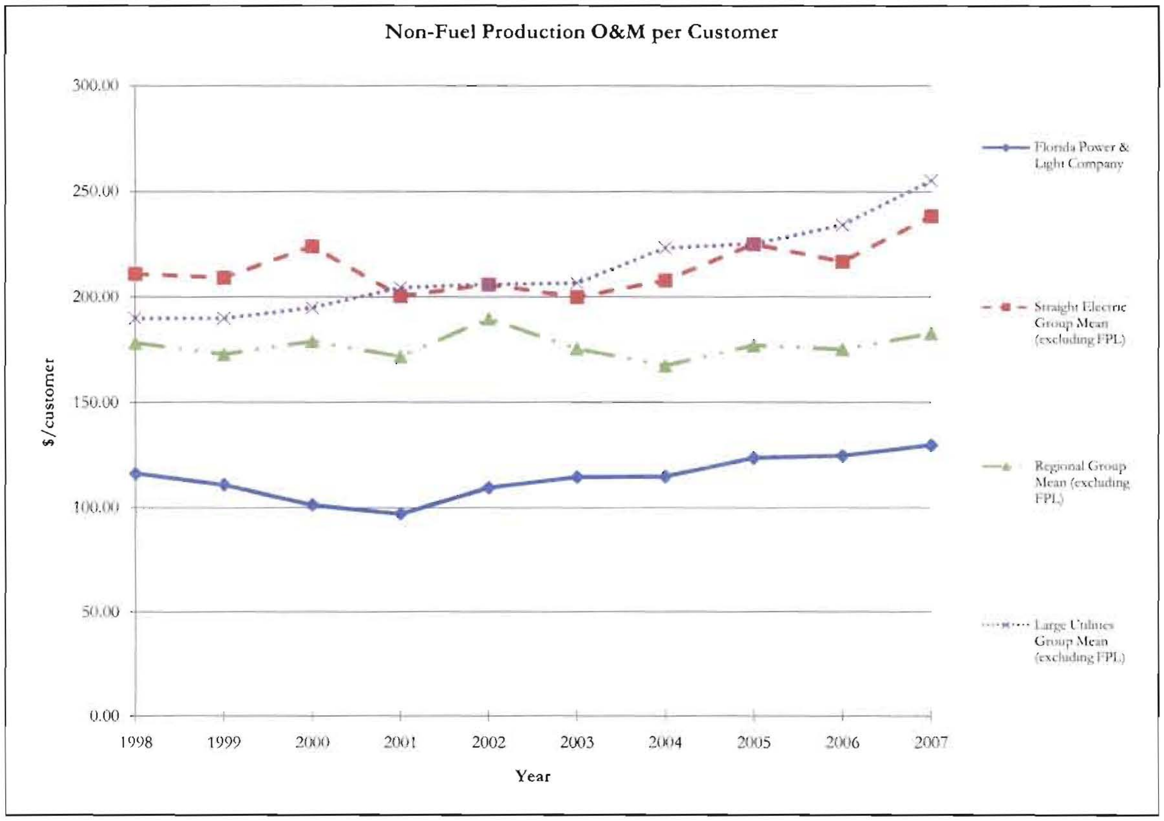
	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	523.60	548.62	560.34	565.56	553.88	474.95	473.38	459.67	448.13	435.85
Straight Electric Group Mean (excluding FPL)	405.29	414.09	423.71	429.50	433.39	384.22	384.18	373.90	364.33	358.91
Regional Group Mean (excluding FPL)	424.36	434.64	445.50	436.46	427.85	420.41	406.67	403.65	397.19	375.89
Large Utilities Group Mean (excluding FPL)	415.41	427.82	368.77	373.10	444.06	418.09	414.92	416.46	415.20	412.41
Rankings	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Straight Electric Group:										
Florida Power & Light Company Rank	2	2	2	2	2	5	6	7	6	6
Total Ranked	27	27	27	27	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	1	1	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	2	2	3
Total Ranked	7	7	7	7	7	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Accumulated Depreciation for Total Electric Plant; Total Electric Utility Plant

Benchmarking Workpapers

Productive Efficiency

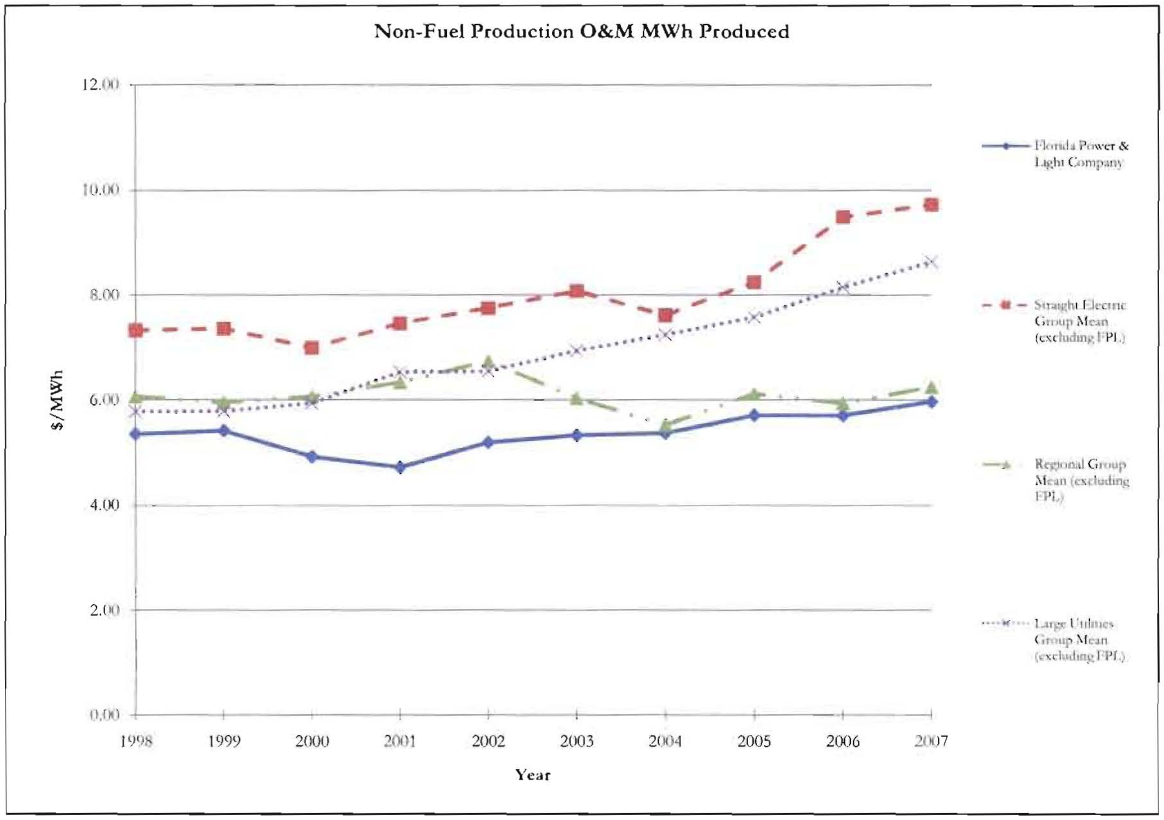
Benchmarking Workpapers
Productive Efficiency



Non-Fuel Production O&M per Customer										
	Annual Values									
	1998	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Florida Power & Light Company	116.23	110.88	101.33	97.05	109.50	114.49	114.72	123.58	124.67	129.73
Straight Electric Group Mean (excluding FPL)	211.01	209.23	224.16	200.39	206.05	199.97	207.88	225.15	216.85	238.43
Regional Group Mean (excluding FPL)	178.20	172.85	178.99	171.77	189.72	175.50	167.37	177.10	175.21	182.84
Large Utilities Group Mean (excluding FPL)	189.91	189.85	195.00	204.57	206.04	206.75	223.42	225.37	234.30	255.39
	Rankings									
	1998	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	6	9	7	5	[illegible]	11	7	7	8	6
Total Ranked	27	27	27	27	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	1	1	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	1	1	1
Total Ranked	7	7	7	7	7	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Total Power Production O&M Expenses less Fuel, Purchased Power, and Other Expenses; Total Customers

Benchmarking Workpapers
Productive Efficiency



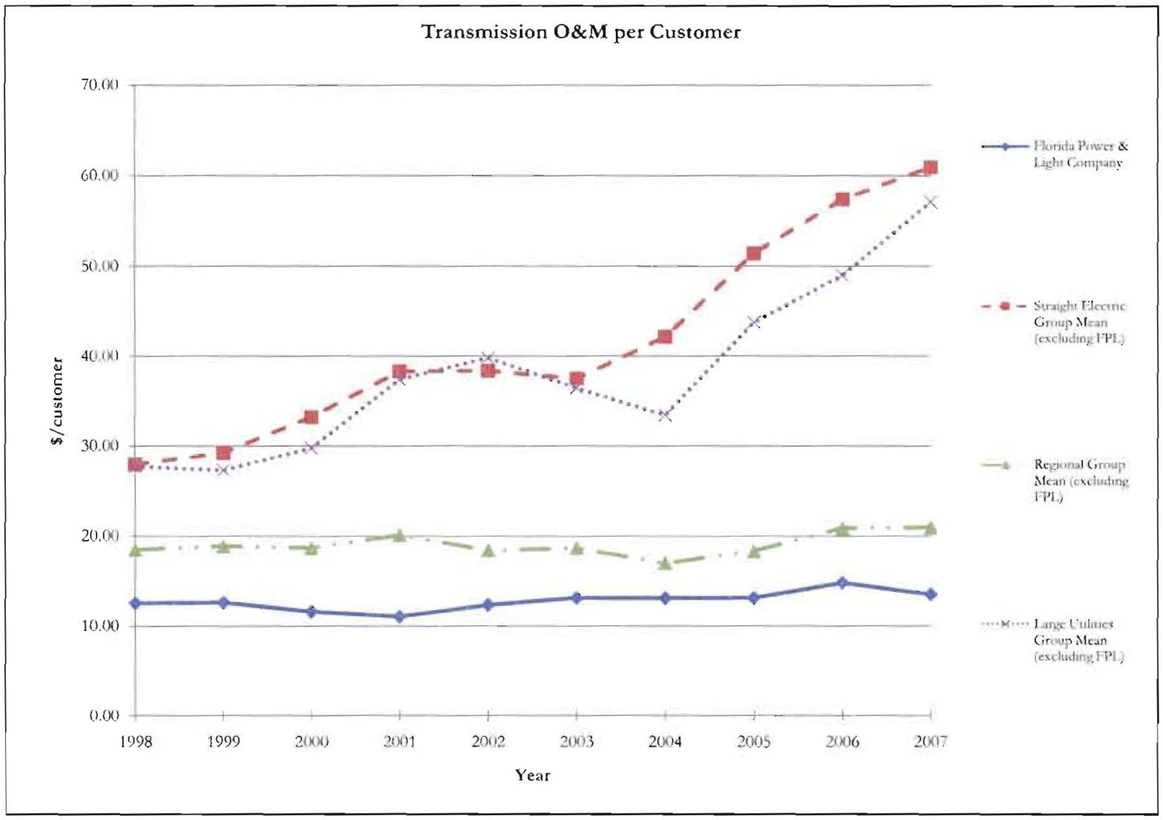
Non-Fuel Production O&M MWh Produced

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	5.36	5.42	4.92	4.72	5.20	5.33	5.37	5.71	5.71	5.97
Straight Electric Group Mean (excluding FPL)	7.33	7.37	7.00	7.47	7.76	8.08	7.62	8.26	9.50	9.74
Regional Group Mean (excluding FPL)	6.07	5.96	6.07	6.34	6.75	6.04	5.53	6.12	5.94	6.25
Large Utilities Group Mean (excluding FPL)	5.78	5.79	5.94	6.54	6.55	6.94	7.25	7.58	8.16	8.65
Rankings	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	11	10	10	7	9	9	7	6	9	5
Total Ranked	27	27	27	27	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	1	2	1	1	1	2	2	2	3	2
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	3	2	1	1	1	1	1	1	1	1
Total Ranked	7	7	7	7	7	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Total Power Production O&M Expenses less Fuel, Purchased Power, and Other Expenses; Total MWh Produced

Benchmarking Workpapers

Productive Efficiency



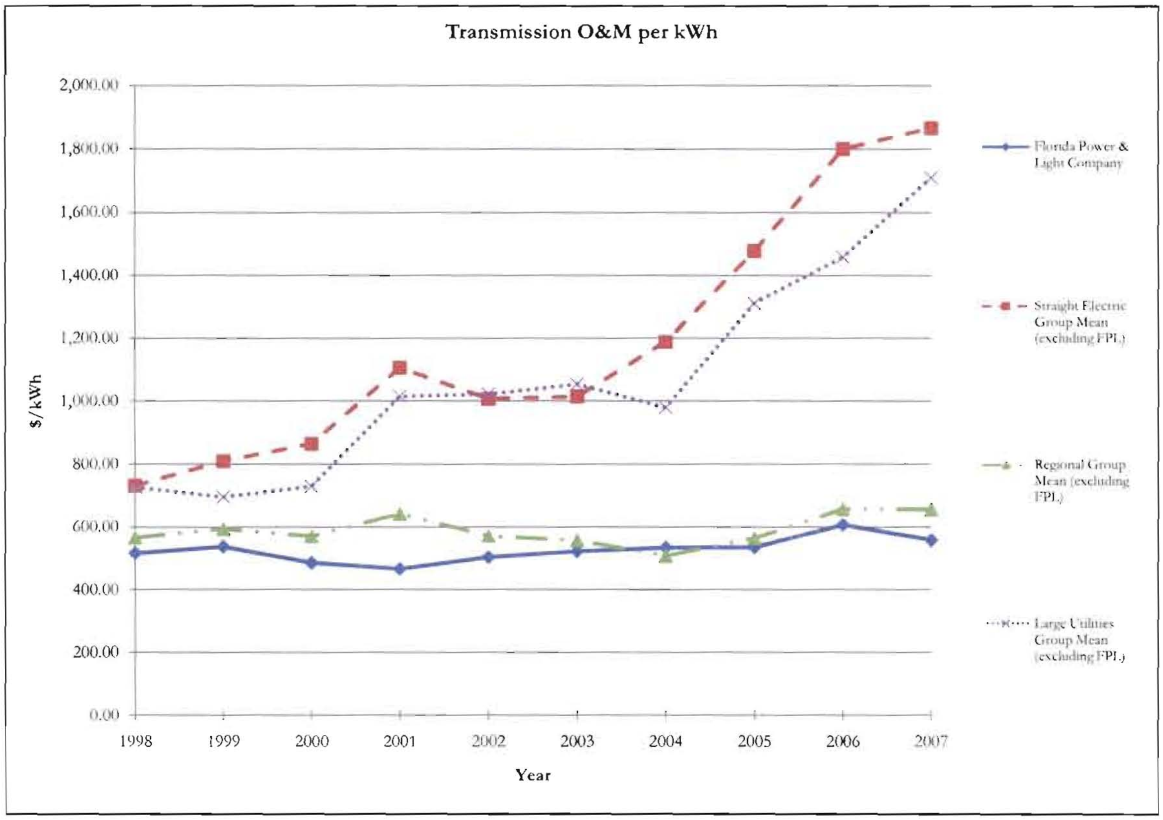
Transmission O&M per Customer

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	12.55	12.63	11.59	11.05	12.36	13.13	13.11	13.14	14.82	13.53
Straight Electric Group Mean (excluding FPL)	28.00	29.27	33.26	38.33	38.39	37.53	42.17	51.47	57.42	60.97
Regional Group Mean (excluding FPL)	18.51	18.90	18.69	20.12	18.44	18.68	17.03	18.35	20.90	20.96
Large Utilities Group Mean (excluding FPL)	27.73	27.32	29.77	37.41	39.84	36.48	33.45	43.80	49.00	57.16
Rankings										
	1998	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	5	4	4	3	6	4	2	3	3	2
Total Ranked	27	27	27	27	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	1	1	1	1	1	2	2	2	1	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	1	2	2	1	2	2	1	2	1	1
Total Ranked	7	7	7	7	7	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Total Transmission O&M Expenses; Total Customers

Benchmarking Workpapers

Productive Efficiency



Transmission O&M per kWh

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	516.95	537.80	485.91	466.46	504.18	523.18	534.60	535.95	607.62	558.89
Straight Electric Group Mean (excluding FPL)	731.41	810.04	864.92	1,105.31	1,007.54	1,013.88	1,188.38	1,478.60	1,799.86	1,866.06
Regional Group Mean (excluding FPL)	567.27	594.10	570.72	642.23	572.27	558.06	507.85	565.07	657.38	656.06
Large Utilities Group Mean (excluding FPL)	727.24	695.88	730.51	1,015.23	1,022.44	1,053.97	980.69	1,311.83	1,458.62	1,710.00
Rankings	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	11	10	6	4	6	5	4	4	7	5
Total Ranked	27	27	27	23	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	2	3	2	2	2	2	2	2	3	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	2	2	2	1	2	2	2	2	2	1
Total Ranked	7	7	7	7	6	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Total Transmission O&M Expenses; Total MWh Sold

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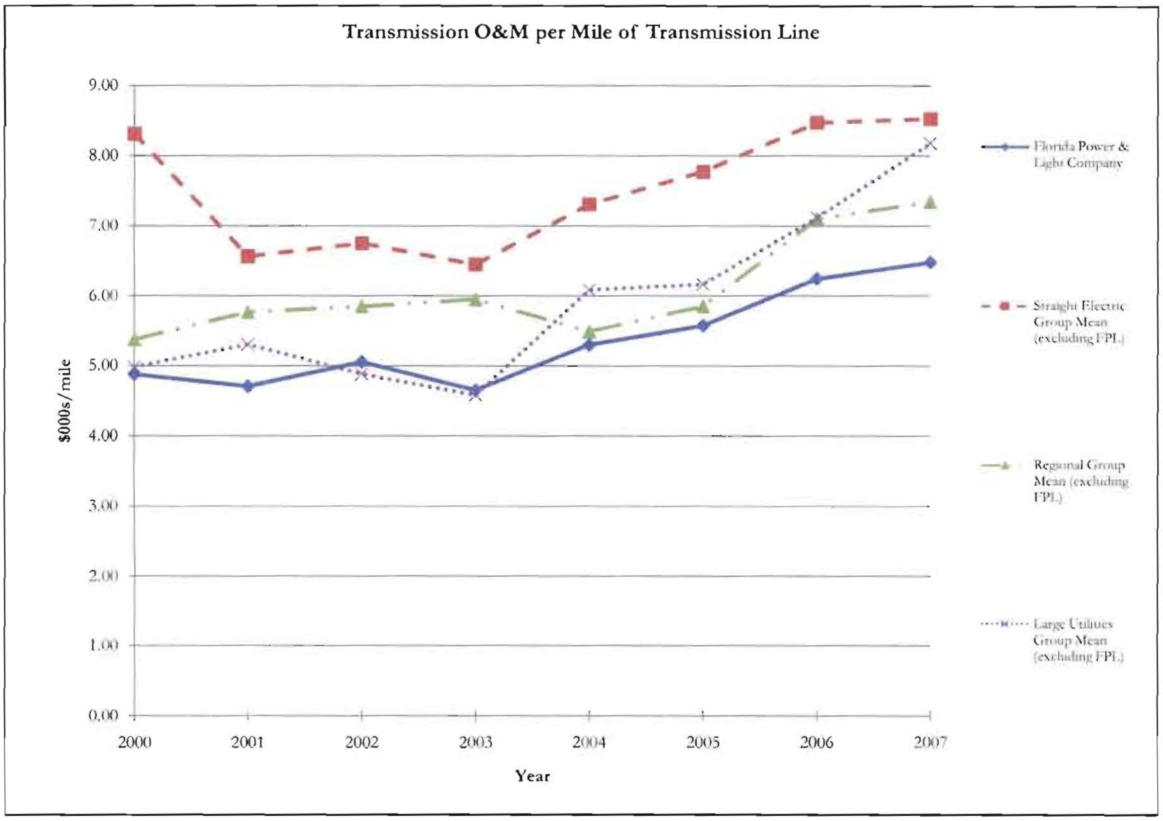
Productive Efficiency



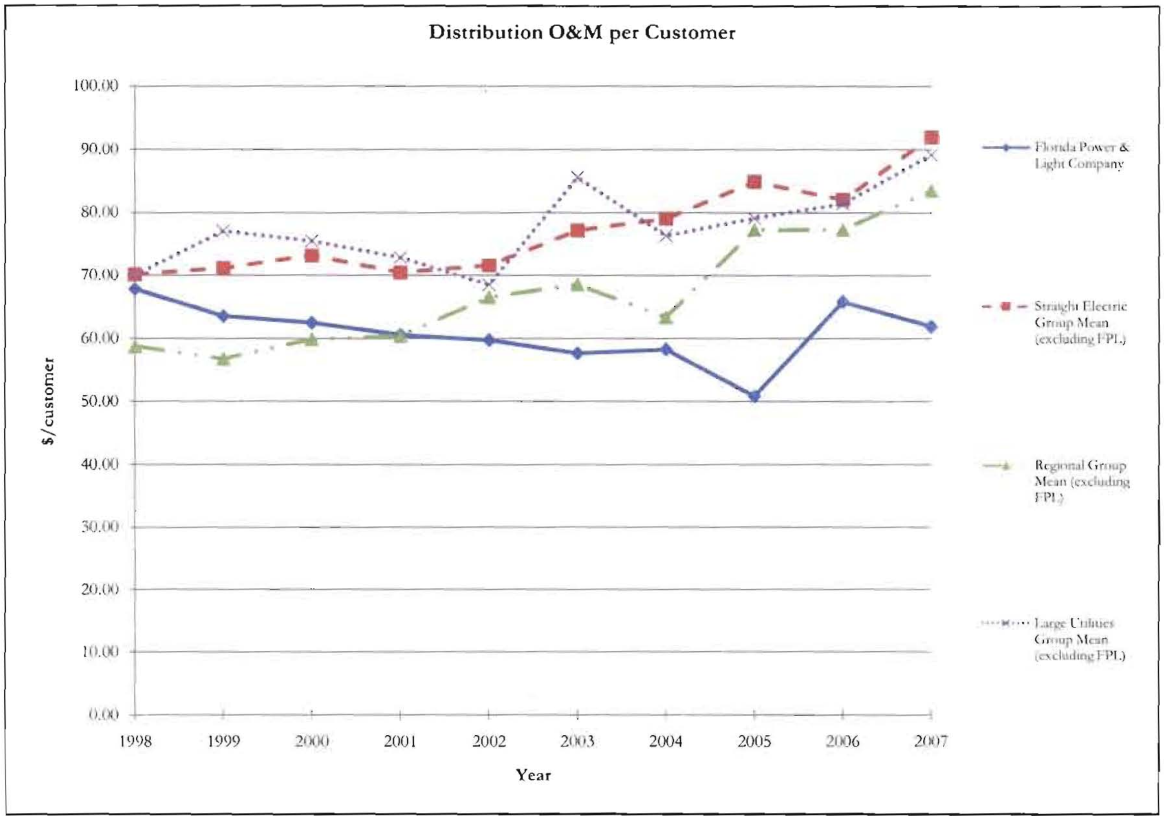
Transmission O&M per Mile of Transmission Line

Annual Values	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Florida Power & Light Company			4.88	4.71	5.06	4.65	5.30	5.58	6.25	6.49
Straight Electric Group Mean (excluding FPL)			8.31	6.57	6.75	6.45	7.31	7.78	8.48	8.53
Regional Group Mean (excluding FPL)			5.38	5.77	5.85	5.95	5.49	5.86	7.11	7.35
Large Utilities Group Mean (excluding FPL)			4.99	5.31	4.88	4.58	6.09	6.17	7.12	8.18
Rankings	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank			16	17	20	16	18	20	19	18
Total Ranked			26	26	26	26	26	26	27	27
Regional Group:										
Florida Power & Light Company Rank			2	1	1	1	2	2	2	2
Total Ranked			4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank			2	2	2	2	2	4	4	2
Total Ranked			3	4	4	4	5	6	6	6

Source: SNL Interactive, FERC Form 1
Total Transmission O&M Expense less Transmission of Electricity by Others; Total Length (Miles) of Transmission Line

Benchmarking Workpapers

Productive Efficiency

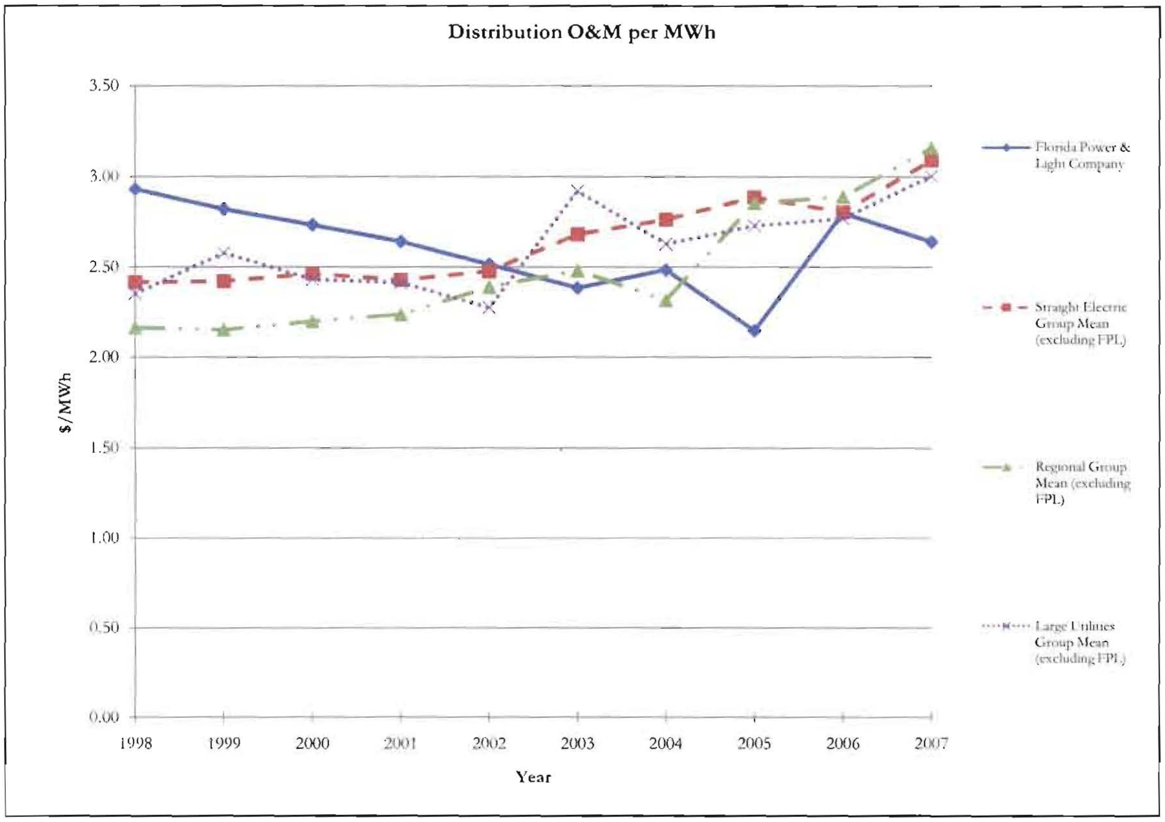


Distribution O&M per Customer

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	67.85	63.57	62.50	60.59	59.77	57.69	58.31	50.89	65.86	61.94
Straight Electric Group Mean (excluding FPL)	70.15	71.17	73.17	70.43	71.60	77.16	79.03	84.90	82.07	91.98
Regional Group Mean (excluding FPL)	58.77	56.81	59.91	60.38	66.59	68.60	63.39	77.28	77.29	83.54
Large Utilities Group Mean (excluding FPL)	70.02	77.11	75.52	72.85	68.56	85.63	76.35	79.13	81.48	89.20
Rankings	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	18	11	9	10	9	4	8	3	6	5
Total Ranked	27	27	27	27	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	3	3	3	3	2	1	3	1	1	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	5	2	3	3	3	2	2	1	3	1
Total Ranked	7	7	7	7	7	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Total Distribution O&M Expenses; Total Ultimate Customers

Benchmarking Workpapers
Productive Efficiency



Distribution O&M per MWh

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	2.93	2.82	2.73	2.64	2.52	2.39	2.49	2.15	2.80	2.64
Straight Electric Group Mean (excluding FPL)	2.42	2.42	2.46	2.43	2.48	2.68	2.76	2.89	2.80	3.09
Regional Group Mean (excluding FPL)	2.17	2.15	2.20	2.24	2.39	2.48	2.32	2.86	2.89	3.16
Large Utilities Group Mean (excluding FPL)	2.35	2.58	2.43	2.42	2.28	2.92	2.63	2.73	2.77	3.01
Rankings	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Straight Electric Group:										
Florida Power & Light Company Rank	24	21	20	21	15	9	12	7	16	12
Total Ranked	27	27	27	27	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	4	4	4	3	3	2	3	2	2	2
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	6	6	6	6	5	4	4	3	5	4
Total Ranked	7	7	7	7	7	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Total Distribution O&M Expenses; Total MWh Sold to Ultimate Customers

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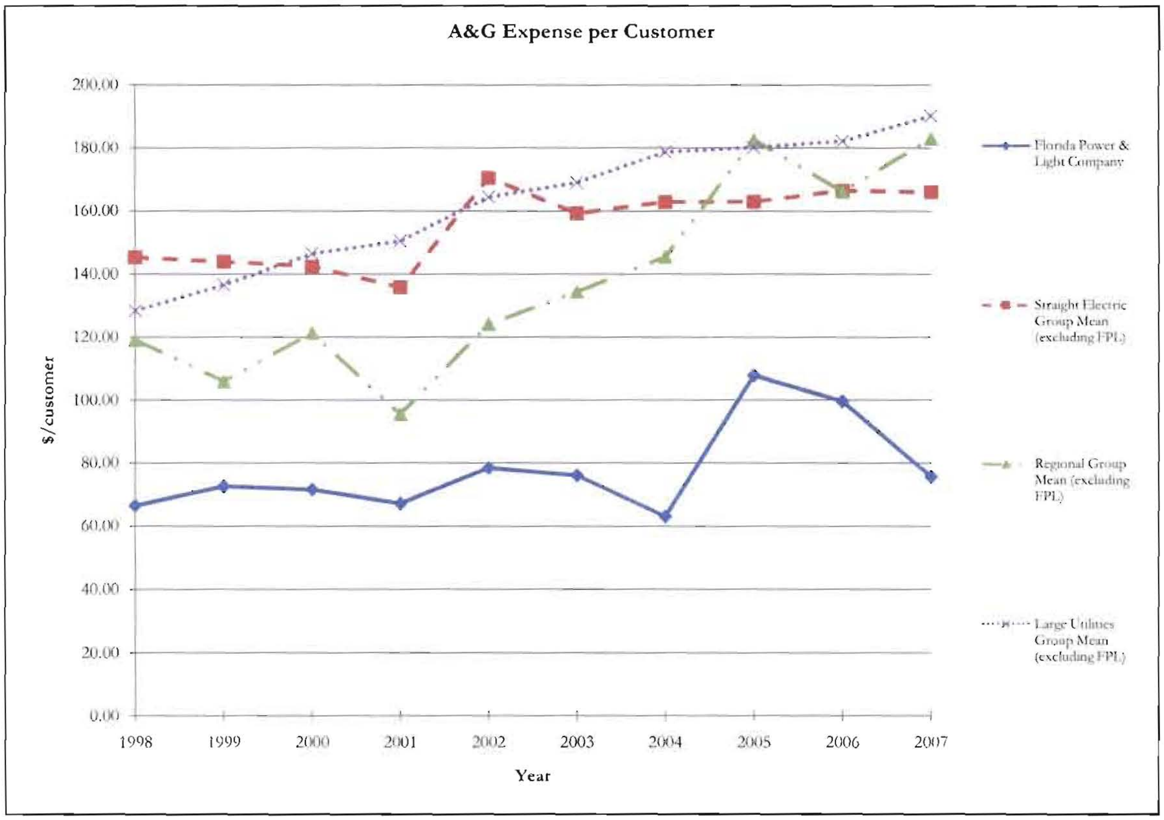
Productive Efficiency



A&G Expense per Customer

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	66.51	72.66	71.60	67.17	78.49	76.11	63.08	107.91	99.64	75.75
Straight Electric Group Mean (excluding FPL)	145.38	143.95	142.45	135.82	170.55	159.27	162.92	163.01	166.57	166.09
Regional Group Mean (excluding FPL)	119.25	106.04	121.36	95.56	124.25	134.48	145.53	182.67	166.24	183.04
Large Utilities Group Mean (excluding FPL)	128.45	136.58	146.49	150.53	164.50	168.99	178.77	180.18	182.23	190.26
Rankings										
	1998	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	1	2	2	2	1	1	1	4	4	3
Total Ranked	27	27	27	27	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	1	2	1	2	1	1	1	1	1	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	1	1	1
Total Ranked	7	7	7	7	7	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Total A&G Expenses; Total Ultimate Customers

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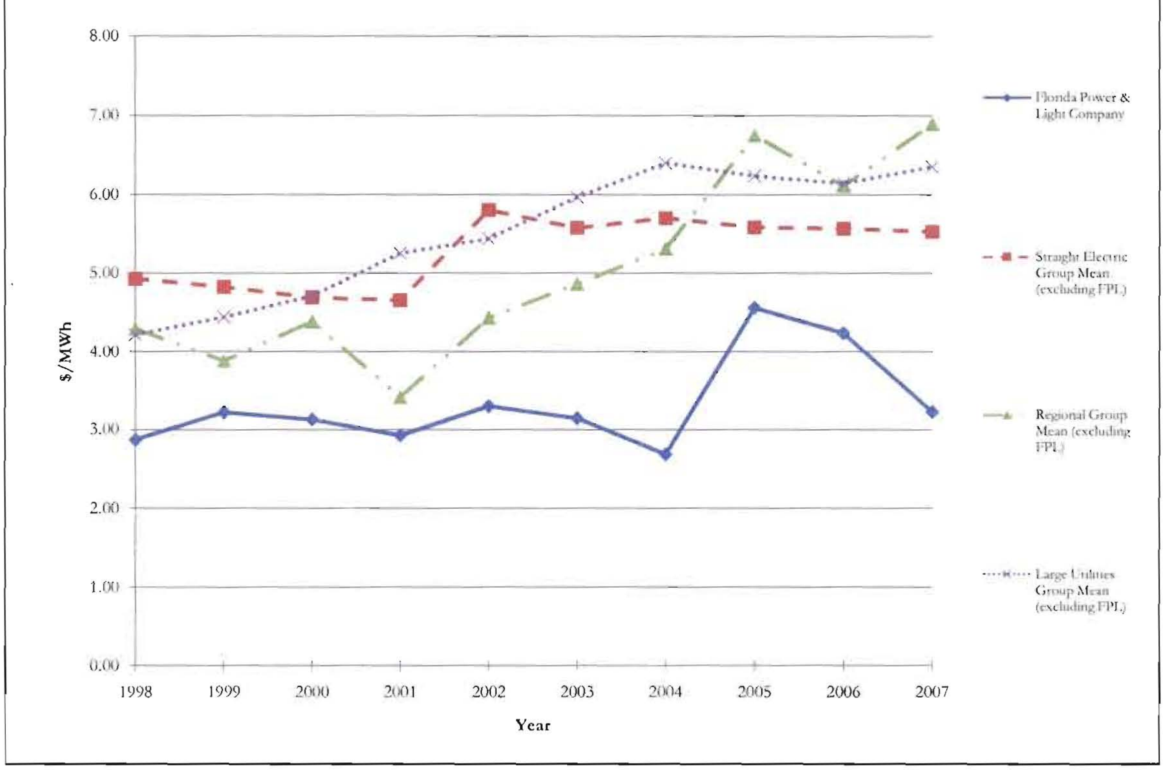
Productive Efficiency

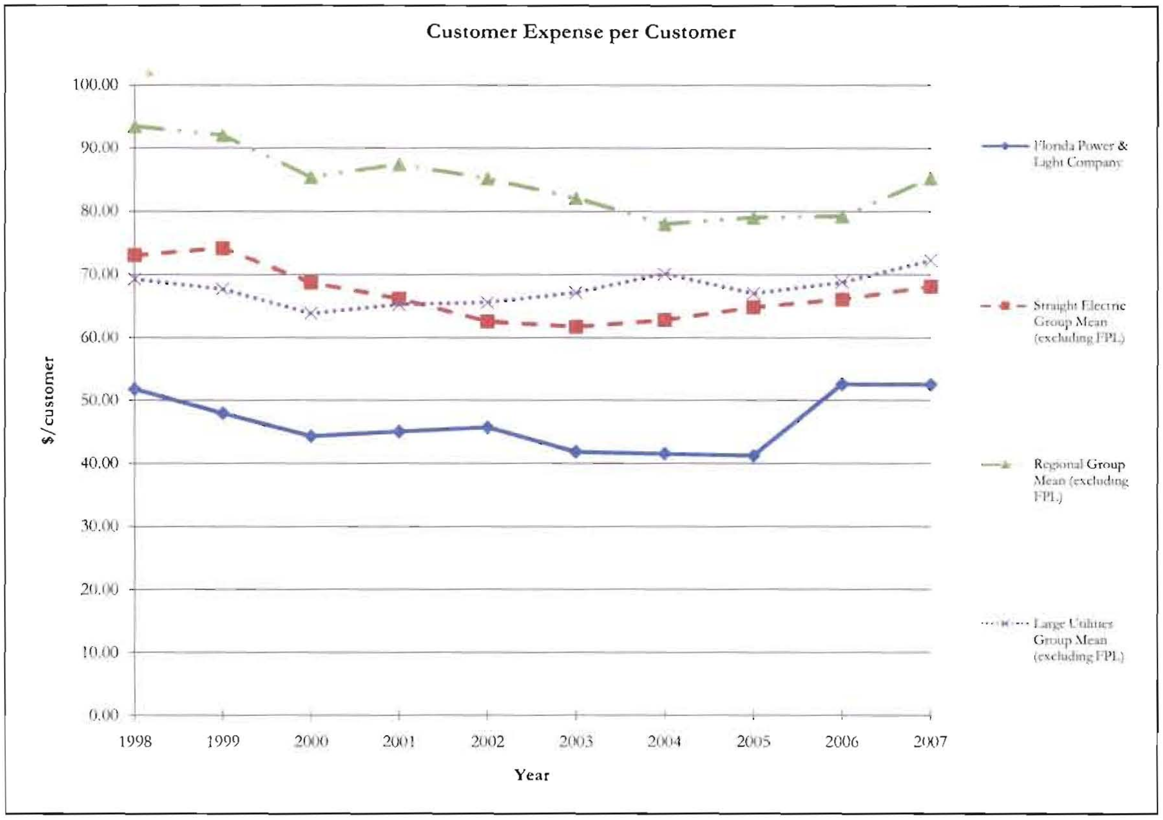


A&G Expense per MWh

Annual Values	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Florida Power & Light Company	2.88	3.23	3.13	2.93	3.30	3.15	2.69	4.56	4.24	3.23
Straight Electric Group Mean (excluding FPL)	4.93	4.82	4.69	4.65	5.81	5.58	5.70	5.59	5.57	5.53
Regional Group Mean (excluding FPL)	4.29	3.88	4.39	3.42	4.43	4.86	5.31	6.75	6.12	6.90
Large Utilities Group Mean (excluding FPL)	4.22	4.44	4.71	5.26	5.44	5.97	6.40	6.24	6.15	6.35
Rankings	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	4	4	4	4	2	3	1	9	8	4
Total Ranked	27	27	27	27	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	2	2	1	2	1	1	1	1	1	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	2	1	1	1	1	1	1	2	1	1
Total Ranked	7	7	7	7	7	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Total A&G Expenses; Total MWh Sold to Ultimate Customers

Benchmarking Workpapers
Productive Efficiency



Customer Expense per Customer

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	51.84	47.98	44.36	45.10	45.76	41.86	41.55	41.25	52.61	52.56
Straight Electric Group Mean (excluding FPL)	73.07	74.17	68.77	66.24	62.62	61.78	62.86	64.87	66.16	68.20
Regional Group Mean (excluding FPL)	93.48	92.03	85.48	87.49	85.25	82.14	78.01	79.03	79.25	85.28
Large Utilities Group Mean (excluding FPL)	69.35	67.77	63.87	65.28	65.62	67.20	70.20	67.09	68.86	72.34
Rankings										
	1998	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	6	4	2	6	8	7	7	2	13	10
Total Ranked	27	27	27	27	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	1	1	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	3	2	2	2	2	2	2	2	2	2
Total Ranked	7	7	7	7	7	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Total Customer Accounts Expenses; Total Customer Service and Informational Expenses; Total Sales Expenses; Total Ultimate Customers

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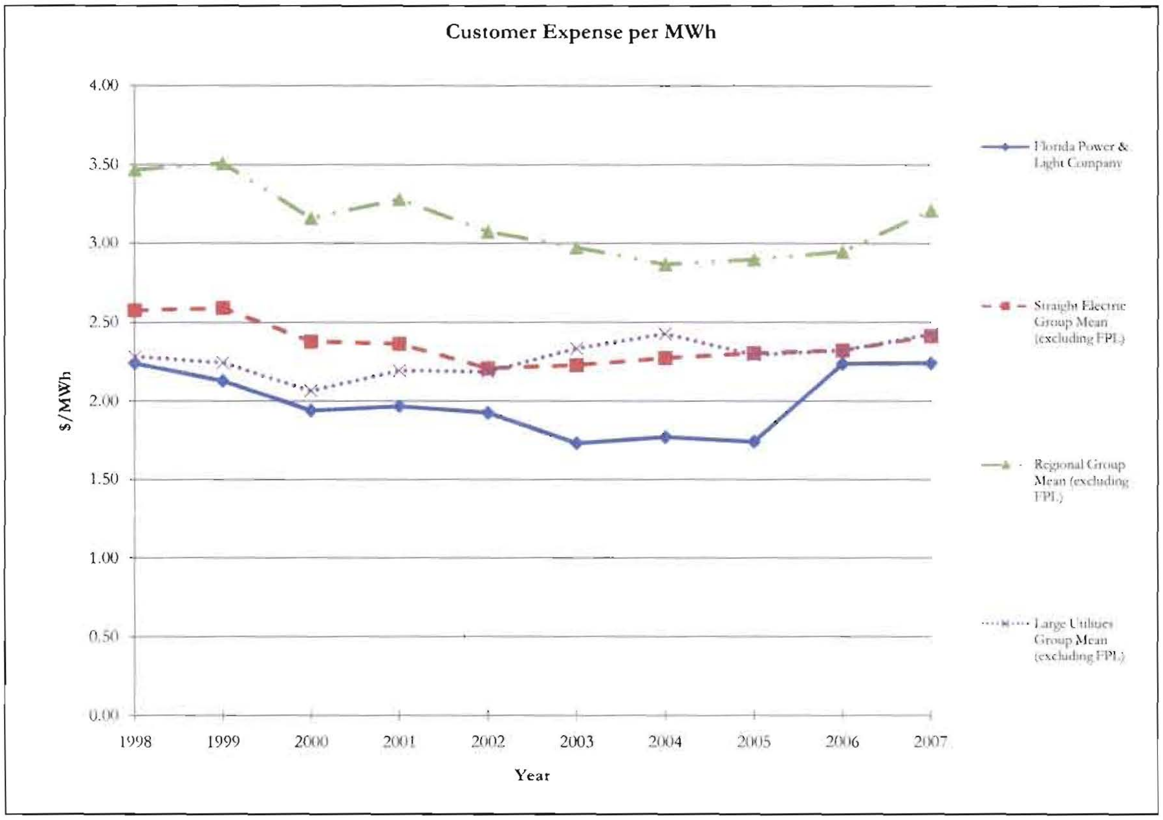
Productive Efficiency

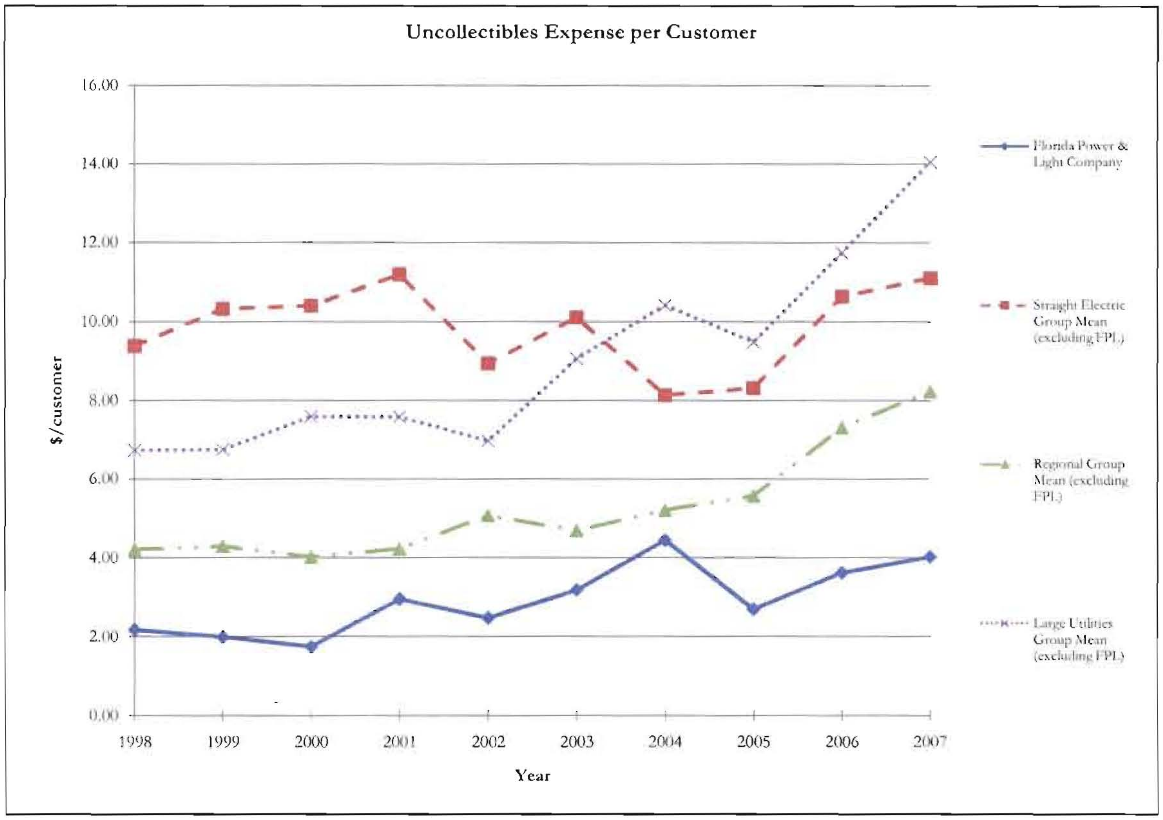


Customer Expense per MWh

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	2.24	2.13	1.94	1.97	1.93	1.73	1.77	1.74	2.24	2.24
Straight Electric Group Mean (excluding FPL)	2.58	2.59	2.38	2.36	2.21	2.23	2.27	2.30	2.32	2.41
Regional Group Mean (excluding FPL)	3.47	3.51	3.16	3.28	3.08	2.97	2.87	2.90	2.95	3.21
Large Utilities Group Mean (excluding FPL)	2.28	2.24	2.07	2.20	2.19	2.33	2.43	2.29	2.32	2.43
Rankings	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	16	14	11	13	15	14	15	15	17	18
Total Ranked	27	27	27	27	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	1	1	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	4	3	3	3	3	2	2	2	4	4
Total Ranked	7	7	7	7	7	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Total Customer Accounts Expenses; Total Customer Service and Informational Expenses; Total Sales Expenses; Total MWh Sold to Ultimate Customers

Benchmarking Workpapers
Productive Efficiency

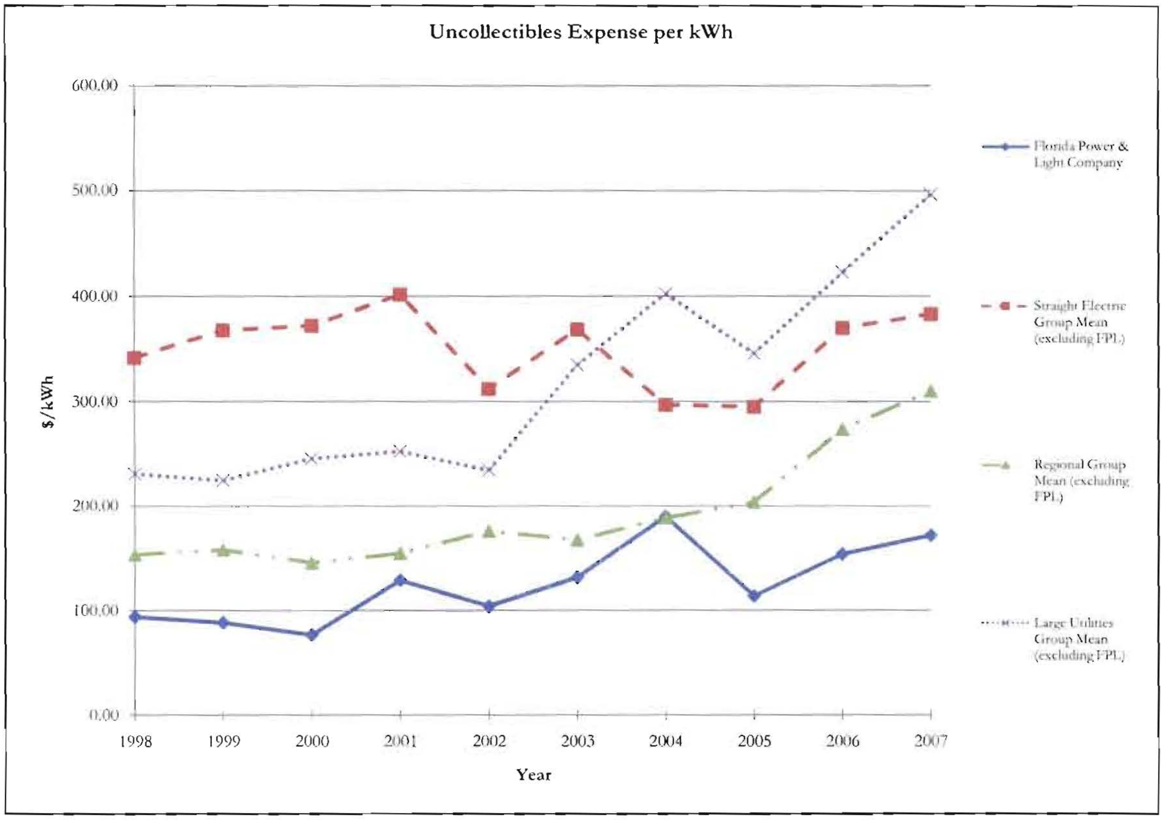


Uncollectibles Expense per Customer

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	2.17	1.99	1.74	2.95	2.47	3.18	4.45	2.69	3.62	4.03
Straight Electric Group Mean (excluding FPL)	9.39	10.33	10.40	11.20	8.94	10.11	8.14	8.32	10.64	11.11
Regional Group Mean (excluding FPL)	4.21	4.29	4.02	4.22	5.08	4.69	5.21	5.58	7.32	8.24
Large Utilities Group Mean (excluding FPL)	6.74	6.76	7.60	7.59	6.98	9.07	10.42	9.49	11.75	14.05
Rankings	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Straight Electric Group:										
Florida Power & Light Company Rank	3	2	4	6	5	5	12	6	6	5
Total Ranked	27	27	27	27	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	1	1	1	2	2	1	2	1	1	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	2	1	1	1
Total Ranked	7	7	7	7	7	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Uncollectible Accounts Expenses; Total Ultimate Customers

Benchmarking Workpapers
Productive Efficiency

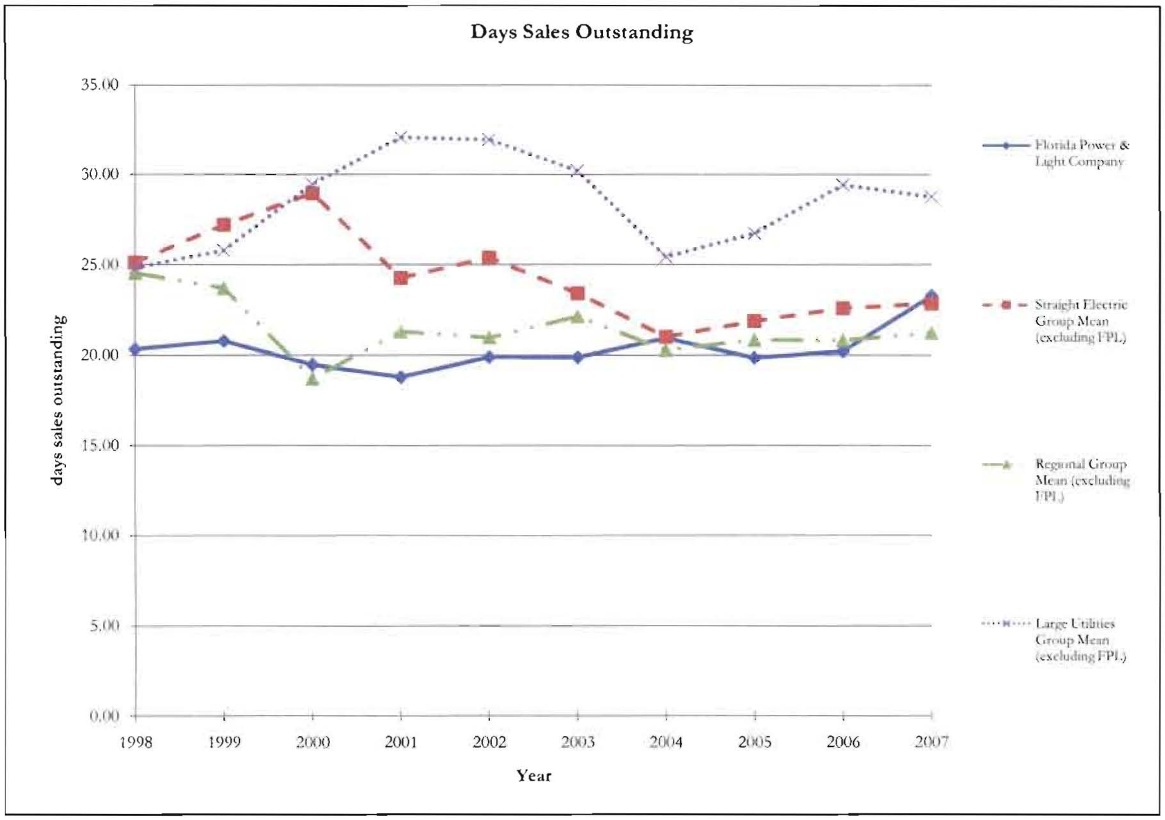


Uncollectibles Expense per kWh

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	93.87	88.27	76.34	128.79	104.00	131.63	189.84	113.74	153.89	171.76
Straight Electric Group Mean (excluding FPL)	342.22	368.25	372.33	401.84	312.33	369.00	297.23	295.33	370.00	383.17
Regional Group Mean (excluding FPL)	153.36	158.06	145.53	154.77	176.00	167.47	188.47	203.74	273.77	310.65
Large Utilities Group Mean (excluding FPL)	230.89	224.60	245.64	252.72	234.38	334.95	402.73	345.86	422.79	496.70
Rankings	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Straight Electric Group:										
Florida Power & Light Company Rank	3	3	5	8	6	7	14	8	9	7
Total Ranked	27	27	27	27	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	1	1	1	2	2	2	3	2	1	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	2	1	1	1
Total Ranked	7	7	7	7	7	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Uncollectible Accounts Expenses; Total MWh Sold to Ultimate Customers

Benchmarking Workpapers
Productive Efficiency



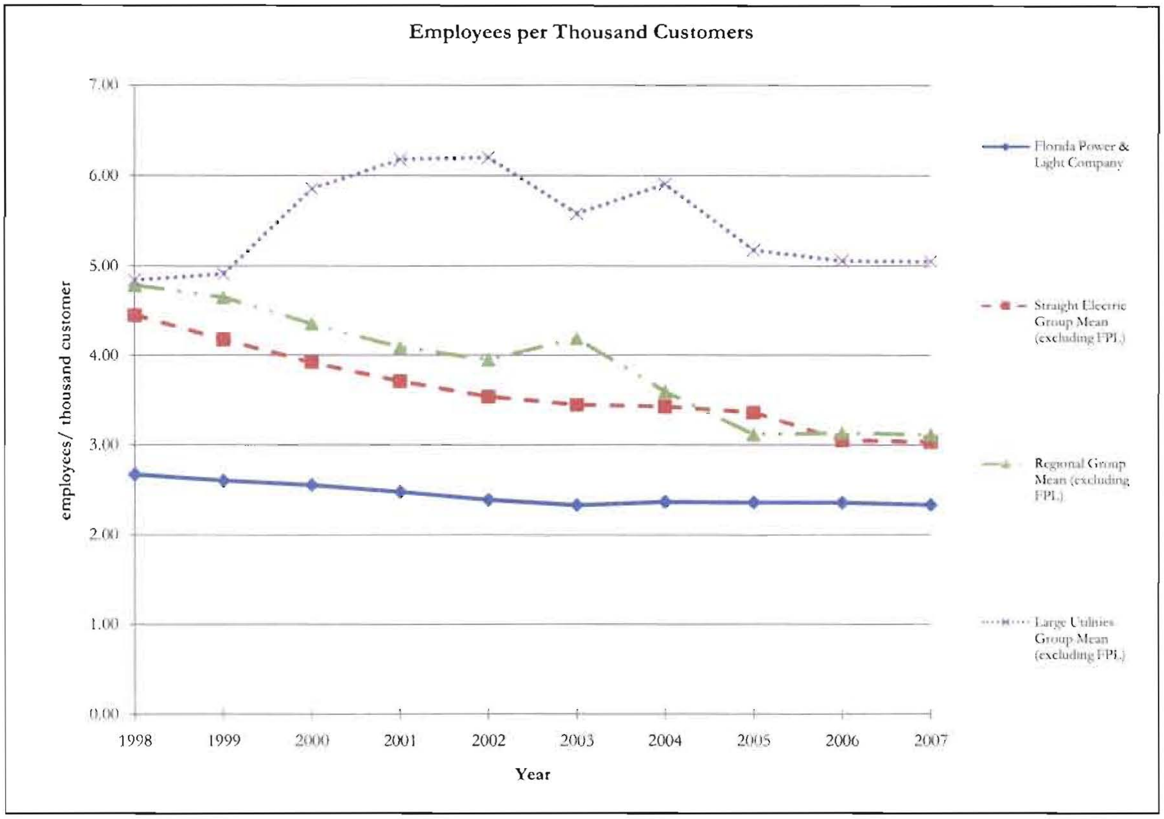
Days Sales Outstanding

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	20.36	20.81	19.49	18.80	19.91	19.89	20.97	19.87	20.24	23.31
Straight Electric Group Mean (excluding FPL)	25.14	27.22	28.97	24.28	25.40	23.44	21.03	21.91	22.62	22.88
Regional Group Mean (excluding FPL)	24.56	23.74	18.72	21.34	21.00	22.17	20.31	20.87	20.84	21.25
Large Utilities Group Mean (excluding FPL)	24.85	25.80	29.49	32.07	31.95	30.22	25.44	26.75	29.43	28.79
Rankings										
	1998	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	7	5	6	13	10	9	13	9	9	13
Total Ranked	25	23	25	26	25	25	26	25	25	25
Regional Group:										
Florida Power & Light Company Rank	1	1	2	2	2	1	3	2	2	3
Total Ranked	3	3	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	3	3	2	2	2	2	3	1	2	3
Total Ranked	7	7	7	7	7	7	6	6	7	7

Source: SNL Interactive, FERC Form 1
Total Sales of Electricity; Average of Customer Accounts Receivable for Current Year and Previous Year

Benchmarking Workpapers

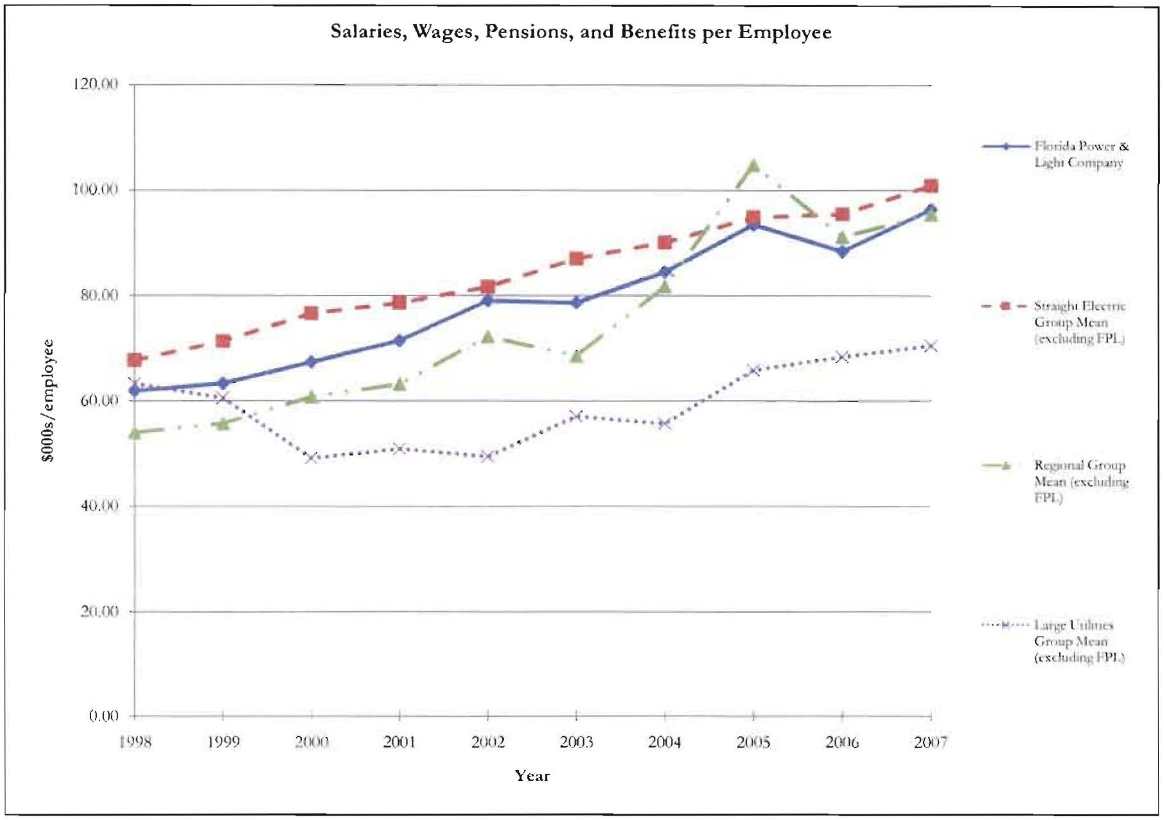
Productive Efficiency



Employees per Thousand Customers										
	Annual Values									
	1998	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Florida Power & Light Company	2.67	2.60	2.56	2.48	2.39	2.33	2.37	2.36	2.36	2.34
Straight Electric Group Mean (excluding FPL)	4.46	4.18	3.92	3.71	3.54	3.45	3.43	3.36	3.05	3.04
Regional Group Mean (excluding FPL)	4.79	4.65	4.36	4.09	3.96	4.19	3.60	3.12	3.13	3.11
Large Utilities Group Mean (excluding FPL)	4.84	4.91	5.86	6.18	6.20	5.58	5.91	5.18	5.06	5.05
	Rankings									
	1998	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	5	5	6	7	7	8	7	9	7	8
Total Ranked	27	26	26	25	26	25	24	25	24	24
Regional Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	2	1	1
Total Ranked	4	4	4	4	4	3	3	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	2	1	1	1	1	1	1	1	1	1
Total Ranked	6	6	7	6	6	7	6	7	7	7

Source: SNL Interactive, FERC Form 1, SEC 10-K Filings
Total Employees; Total Customers

Benchmarking Workpapers
Productive Efficiency

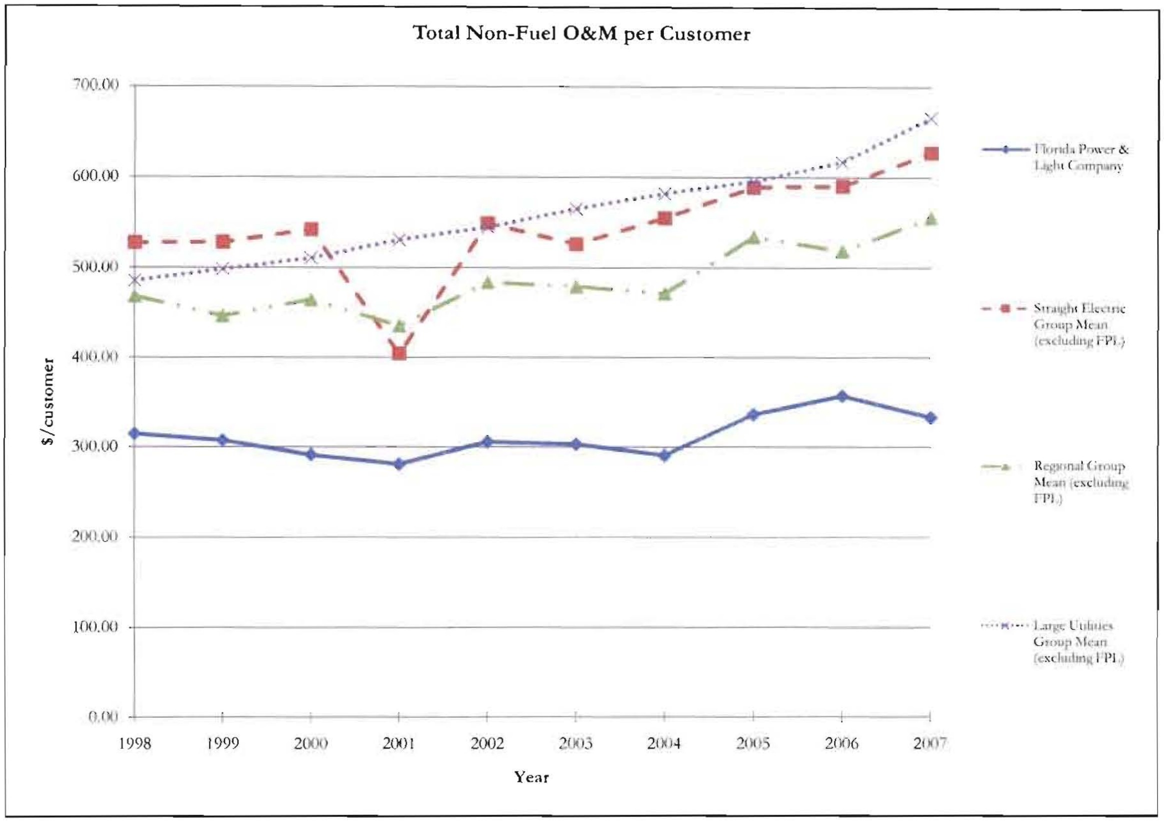


Salaries, Wages, Pensions, and Benefits per Employee

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	61.93	63.36	67.42	71.51	79.14	78.73	84.55	93.53	88.47	96.44
Straight Electric Group Mean (excluding FPL)	67.73	71.36	76.67	78.65	81.73	87.06	90.13	94.92	95.51	100.96
Regional Group Mean (excluding FPL)	54.04	55.78	60.82	63.22	72.30	68.57	81.87	104.93	91.28	95.51
Large Utilities Group Mean (excluding FPL)	63.29	60.58	49.15	50.92	49.46	57.09	55.73	65.90	68.42	70.56
Rankings	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	10	10	7	9	13	11	12	16	10	12
Total Ranked	27	26	26	25	26	25	24	24	24	24
Regional Group:										
Florida Power & Light Company Rank	4	4	4	4	3	3	3	3	2	3
Total Ranked	4	4	4	4	4	3	3	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	4	4	6	5	6	7	6	5	7	7
Total Ranked	6	6	7	6	6	7	6	6	7	7

Source: SNL Interactive, FERC Form 1, SEC 10-K Filings
Total Electric Salaries and Wages; Total Pensions and Benefits; Total Employees (Large Utility Group include employees from non-electric utility operations)

Benchmarking Workpapers
Productive Efficiency

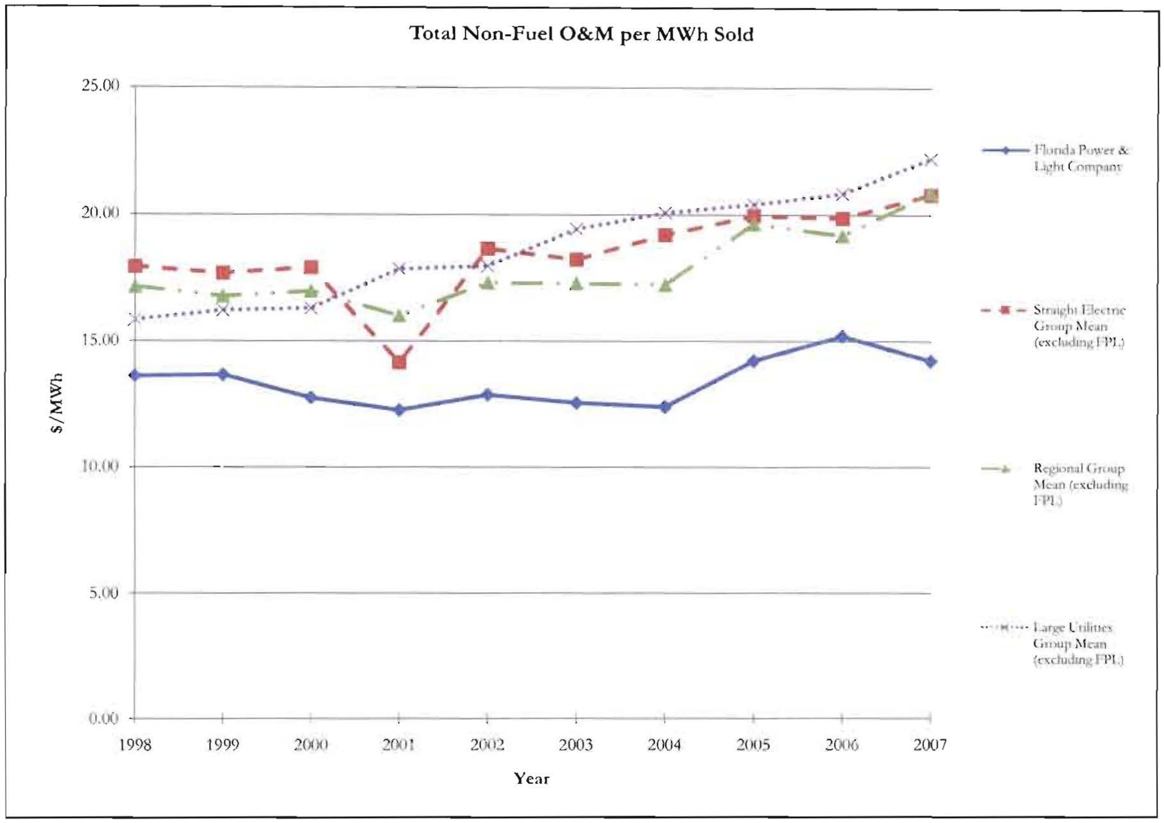


Total Non-Fuel O&M per Customer

Annual Values	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Florida Power & Light Company	314.98	307.72	291.37	280.95	305.87	303.28	290.77	336.76	357.59	333.51
Straight Electric Group Mean (excluding FPL)	527.63	528.19	541.83	404.36	549.23	526.15	554.88	589.41	590.59	627.81
Regional Group Mean (excluding FPL)	468.20	446.62	464.43	435.33	484.26	479.41	471.33	534.43	518.89	555.66
Large Utilities Group Mean (excluding FPL)	485.48	498.63	510.66	530.65	544.56	565.05	582.19	595.57	617.24	666.47
Rankings	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	2	1	1	6	1	2	1	1	3	1
Total Ranked	27	27	27	27	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	1	1	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	1	1	1
Total Ranked	7	7	7	7	7	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Total O&M Expenses less Fuel, Purchased Power, and Other; Total Ultimate Customers

Benchmarking Workpapers
Productive Efficiency



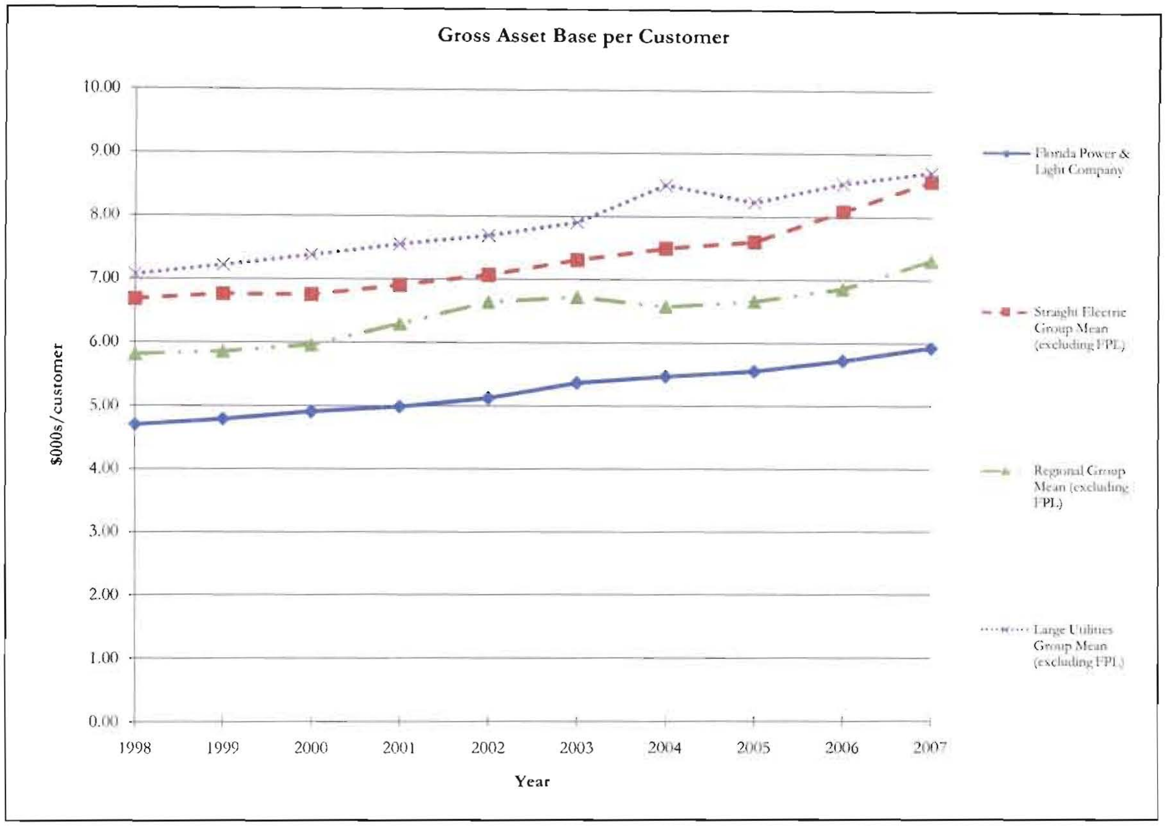
Total Non-Fuel O&M per MWh Sold

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	13.62	13.66	12.75	12.26	12.87	12.55	12.40	14.23	15.21	14.23
Straight Electric Group Mean (excluding FPL)	17.94	17.69	17.91	14.16	18.66	18.23	19.21	19.96	19.87	20.79
Regional Group Mean (excluding FPL)	17.15	16.78	16.97	16.01	17.31	17.29	17.24	19.65	19.18	20.87
Large Utilities Group Mean (excluding FPL)	15.86	16.22	16.30	17.86	17.97	19.44	20.08	20.40	20.84	22.21
Rankings	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	6	7	6	8	7	5	3	6	9	4
Total Ranked	27	27	27	27	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	1	1	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	2	1	1	1	2	1	1	2	2	1
Total Ranked	7	7	7	7	7	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Total O&M Expenses less Fuel, Purchased Power, and Other; Total MWh Sold to Ultimate Customers

Benchmarking Workpapers

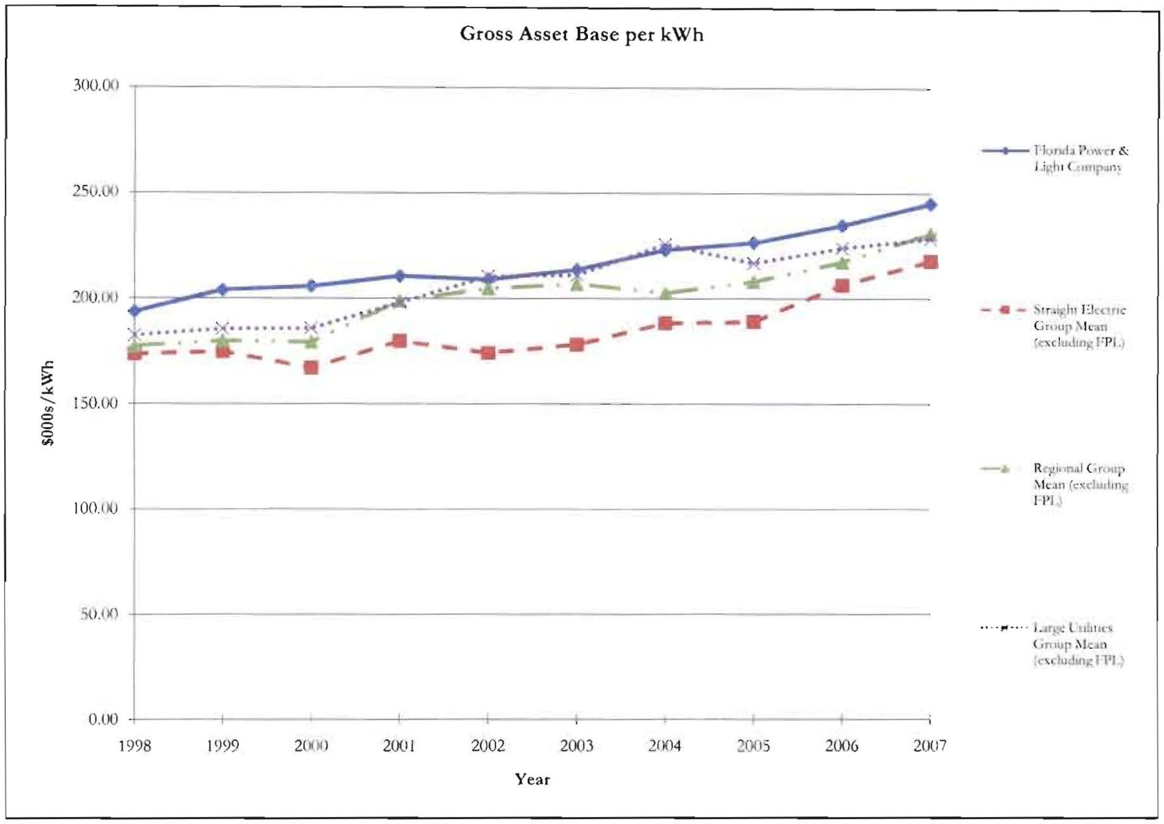
Productive Efficiency



Gross Asset Base per Customer										
Annual Values										
	1998	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Florida Power & Light Company	4.71	4.79	4.91	4.99	5.13	5.37	5.47	5.56	5.73	5.93
Straight Electric Group Mean (excluding FPL)	6.69	6.76	6.76	6.91	7.07	7.31	7.50	7.60	8.09	8.57
Regional Group Mean (excluding FPL)	5.81	5.86	5.96	6.29	6.64	6.72	6.57	6.66	6.86	7.31
Large Utilities Group Mean (excluding FPL)	7.07	7.22	7.38	7.55	7.69	7.90	8.50	8.23	8.52	8.71
Rankings										
	1998	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank	4	3	5	6	6	6	6	6	5	5
Total Ranked	27	27	27	27	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	1	1	1
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	1	1	1	1	1	1	1	1	1	1
Total Ranked	7	7	7	7	7	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Total Electric Utility Plant; Total Customers

Benchmarking Workpapers
Productive Efficiency



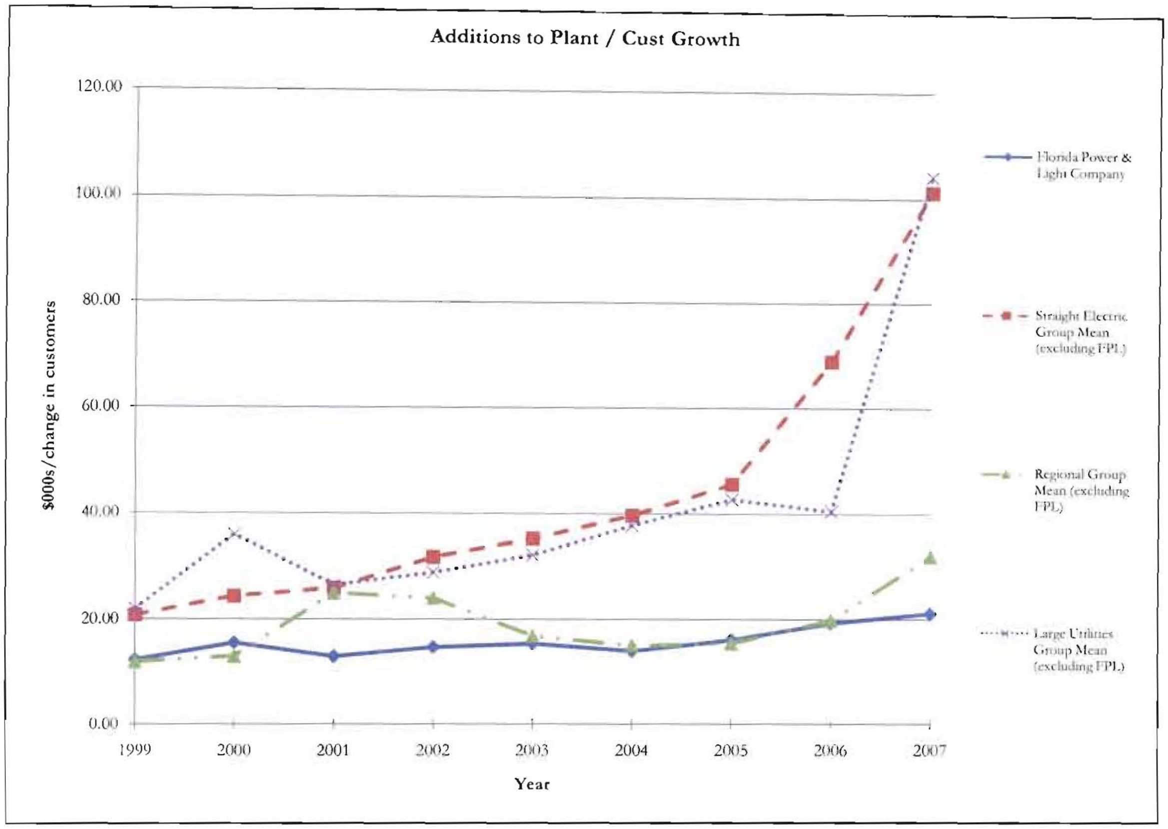
Gross Asset Base per kWh

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company	193.82	204.07	205.94	210.76	209.16	213.84	223.17	226.69	234.86	245.16
Straight Electric Group Mean (excluding FPL)	173.78	174.92	167.19	180.01	174.33	178.41	188.57	189.25	206.56	217.93
Regional Group Mean (excluding FPL)	177.66	180.13	179.50	199.06	204.98	207.13	202.83	208.29	217.58	231.13
Large Utilities Group Mean (excluding FPL)	182.63	185.67	185.97	198.02	210.59	211.23	225.97	216.96	224.14	228.56
Rankings	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Straight Electric Group:										
Florida Power & Light Company Rank	17	21	21	15	20	21	20	17	17	17
Total Ranked	27	27	27	23	27	27	27	27	28	28
Regional Group:										
Florida Power & Light Company Rank	3	3	3	3	3	3	3	3	3	2
Total Ranked	4	4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank	5	6	5	4	3	4	3	4	4	4
Total Ranked	7	7	7	7	6	7	6	7	7	7

Source: SNL Interactive, FERC Form 1
Total Electric Utility Plant; Total MWh Sold

Benchmarking Workpapers

Productive Efficiency



Additions to Plant / Cust Growth

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Annual Values										
Florida Power & Light Company		12.26	15.48	12.88	14.65	15.36	13.98	16.07	19.28	21.17
Straight Electric Group Mean (excluding FPL)		20.79	24.36	25.93	31.77	35.27	39.68	45.66	68.95	101.33
Regional Group Mean (excluding FPL)		11.87	12.96	24.97	24.00	16.81	15.03	15.40	19.83	31.98
Large Utilities Group Mean (excluding FPL)		21.93	35.98	26.44	28.81	32.10	37.79	42.74	40.48	104.29
Rankings										
	1998	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Straight Electric Group:										
Florida Power & Light Company Rank		7	9	6	6	4	3	4	6	4
Total Ranked		26	26	27	26	27	27	27	27	26
Regional Group:										
Florida Power & Light Company Rank		3	3	2	2	2	3	3	2	2
Total Ranked		4	4	4	4	4	4	4	4	4
Large Utility Group:										
Florida Power & Light Company Rank		1	1	1	1	1	1	1	1	1
Total Ranked		7	7	7	7	7	6	6	5	5

Source: SNL Interactive, FERC Form 1
Gross Additions to Utility Plant (less nuclear fuel); Total Customers (change in 2 year average number of customers)

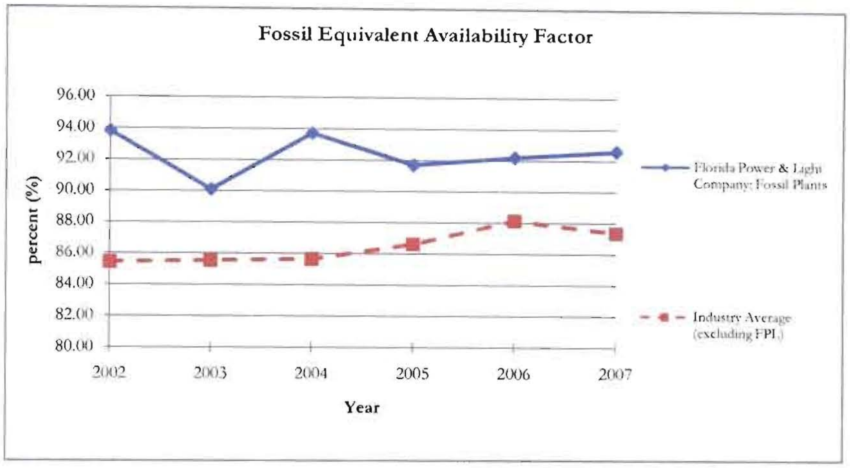
Benchmarking Workpapers
Operational Metrics

Benchmarking Workpapers

Operational Metrics

Fossil Plant Performance

Benchmarking Workpapers
Operational Metrics

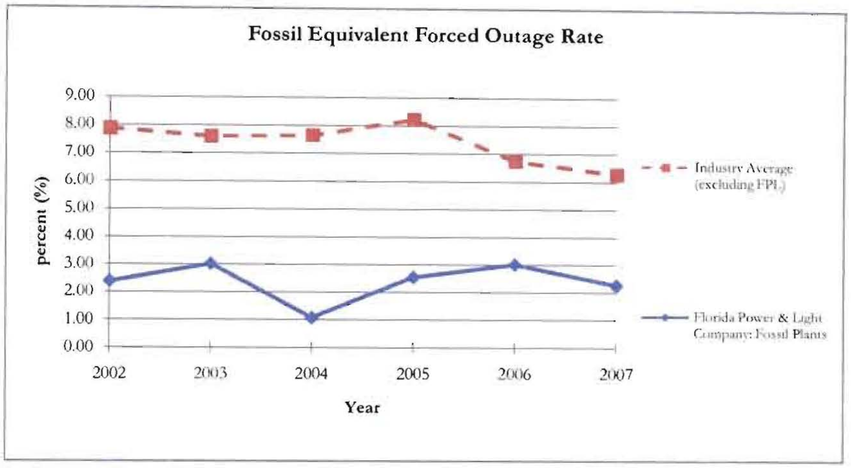


Fossil Equivalent Availability Factor						
	Annual Values					
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Florida Power & Light Company: Fossil Plants	93.80	90.10	93.70	91.70	92.20	92.60
Industry Average (excluding FPL)	85.43	85.54	85.63	86.61	88.13	87.36
	Rankings					
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
FPL compared to companies comprising Industry Average:						
Florida Power & Light Company Rank	1	7	1	5	8	4
Total Ranked	37	37	37	37	36	36

Source: North American Electric Reliability Council (NERC). Weighted Equivalent Availability Factor (excluding Maintenance Outage Factor) for fossil steam and combined cycle units for all reporting companies.
FPL data internally generated.

FPL EAF was impacted 0.6% in '05 by Hurricane Wilma, and 1.0% in '06 by GE 7FA CT industry-wide Compressor (Stator & R-0 Blade) issues.

Benchmarking Workpapers
Operational Metrics



Fossil Equivalent Forced Outage Rate						
	Annual Values					
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Florida Power & Light Company: Fossil Plants	2.39	3.02	1.08	2.55	3.02	2.27
Industry Average (excluding FPL)	7.88	7.60	7.65	8.22	6.74	6.28
	Rankings					
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
FPL compared to companies comprising Industry Average:						
Florida Power & Light Company Rank	3	8	2	4	7	6
Total Ranked	37	37	37	37	36	36

Source: North American Electric Reliability Council (NERC). Weighted Weighted Equivalent Forced Outage Rate for fossil steam and combined cycle units for all reporting companies.
FPL data internally generated.

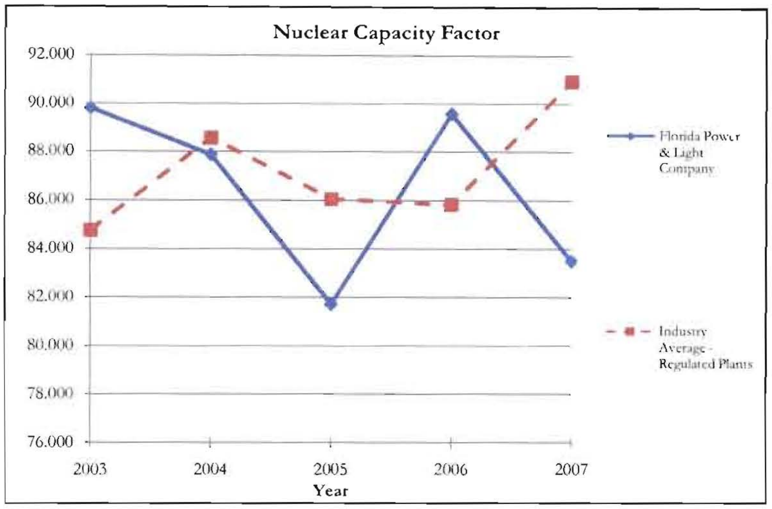
FPL EFOR was impacted 0.53% in '05 by Hurricane Wilma, and 1.31% in '06 by GE 7FA CT industry-wide Compressor (Stator & R-0 Blade) issues.

Benchmarking Workpapers

Operational Metrics

Nuclear Plant Performance

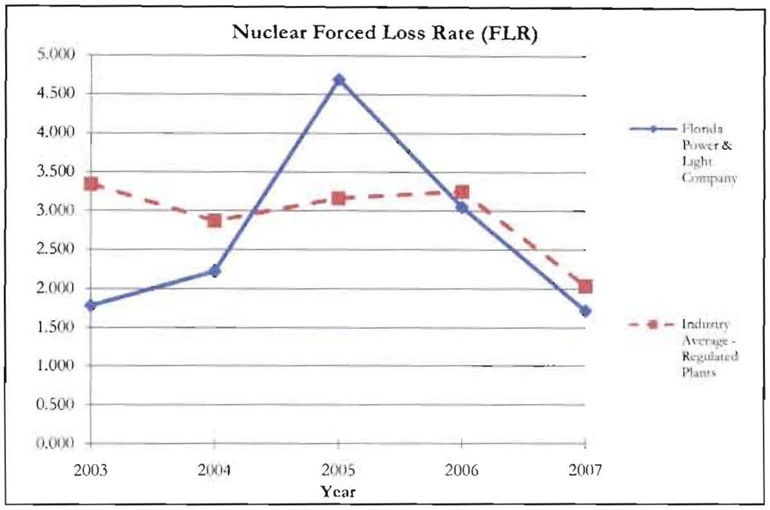
Benchmarking Workpapers
Operational Metrics



Nuclear Capacity Factor					
Reported Annually for Nominal Operating Cycle					
	2003	**2004**	**2005**	**2006**	**2007**
Florida Power & Light Company	89.801	87.884	81.715	89.577	83.506
Industry Average - Regulated Plants	84.763	88.570	86.052	85.828	90.929
Florida Power & Light - Ranking	8 of 21	14 of 21	16 of 21	10 of 21	19 of 21

Source: SNL Financial, Energy Information Administration (EIA)
Notes: St. Lucie and Turkey Point are both Regulated Plants

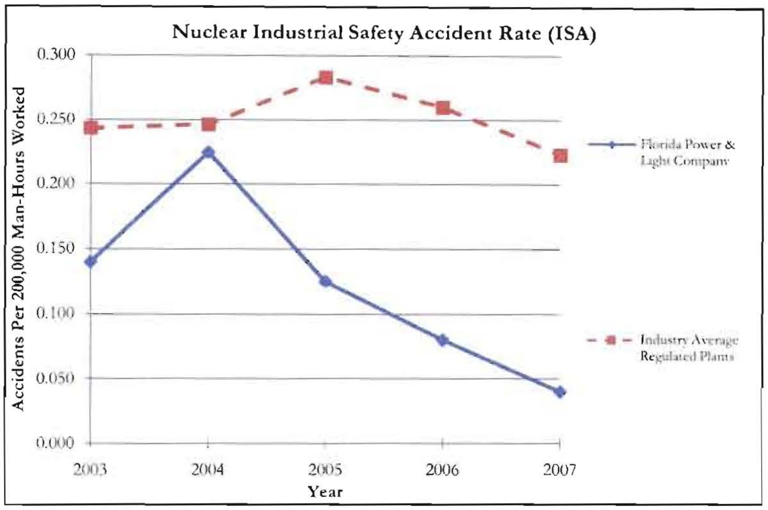
Benchmarking Workpapers
Operational Metrics



Nuclear Forced Loss Rate (FLR)					
Reported Annually for Nominal Operating Cycle					
	2003	**2004**	**2005**	**2006**	**2007**
Florida Power & Light Company	1.783	2.223	4.693	3.050	1.720
Industry Average - Regulated Plants	3.343	2.869	3.161	3.251	2.035
Florida Power & Light - Ranking	9 of 21	12 of 21	17 of 21	15 of 21	13 of 21

Source: Institute of Nuclear Power Operations
Notes: St. Lucie and Turkey Point are both Regulated Plants

Benchmarking Workpapers
Operational Metrics



Nuclear Industrial Safety Accident Rate (ISA)					
Reported Annually for Nominal Operating Cycle					
	2003	**2004**	**2005**	**2006**	**2007**
Florida Power & Light Company	0.140	0.225	0.125	0.080	0.040
Industry Average - Regulated Plants	0.243	0.247	0.283	0.260	0.223
Florida Power & Light - Ranking	10 of 21	13 of 21	9 of 21	8 of 21	6 of 21

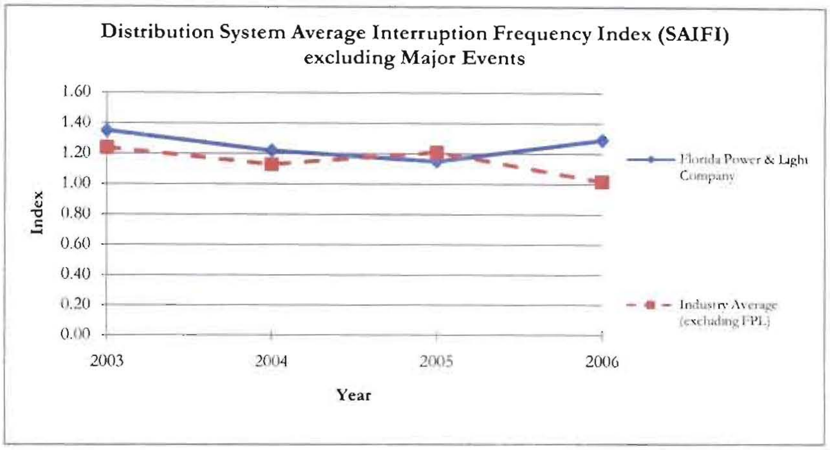
Source: Institute of Nuclear Power Operations
Notes: St. Lucie and Turkey Point are both Regulated Plants

Benchmarking Workpapers

Operational Metrics

Distribution System Reliability

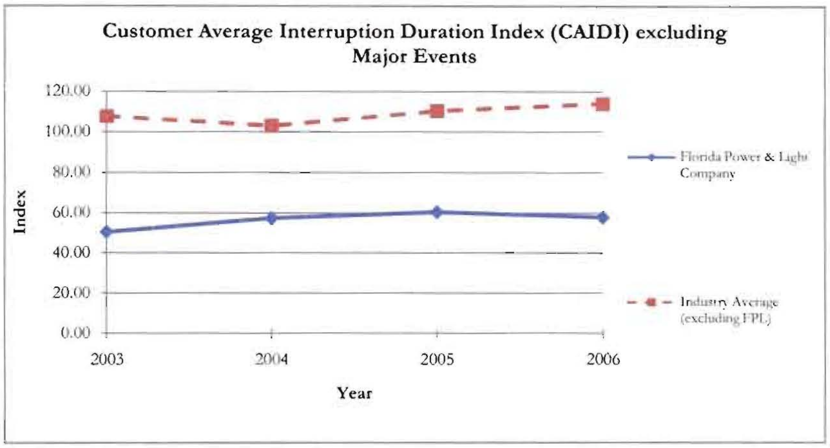
Benchmarking Workpapers
Operational Metrics



Distribution System Average Interruption Frequency Index (SAIFI) excluding Major Events				
Annual Values				
	2003	2004	2005	2006
Florida Power & Light Company	1.35	1.22	1.15	1.29
Industry Average (excluding FPL)	1.24	1.13	1.21	1.02
Rankings				
	2003	2004	2005	2006
FPL compared to companies comprising Industry Average:				
Florida Power & Light Company Rank	42	48	30	50
Total Ranked	63	76	66	69

Source: Edison Electric Institute (EEI)
Distribution System Average Interruption Frequency Index (SAIFI) excluding Major Events

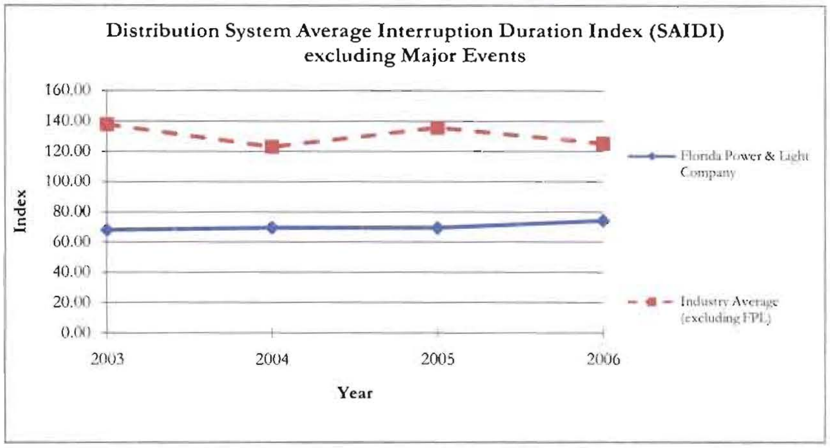
Benchmarking Workpapers
Operational Metrics



Customer Average Interruption Duration Index (CAIDI) excluding Major Events				
	Annual Values			
	2003	2004	2005	2006
Florida Power & Light Company	50.50	57.30	60.40	57.80
Industry Average (excluding FPL)	107.72	103.00	110.46	114.11
	Rankings			
	2003	2004	2005	2006
FPL compared to companies comprising Industry Average:				
Florida Power & Light Company Rank	3	5	3	8
Total Ranked	63	76	66	70

Source: Edison Electric Institute (EEI)
Customer Average Interruption Duration Index (CAIDI) excluding Major Events

Benchmarking Workpapers
Operational Metrics



Distribution System Average Interruption Duration Index (SAIDI) excluding Major Events				
Annual Values				
	2003	2004	2005	2006
Florida Power & Light Company	68.20	69.70	69.60	74.30
Industry Average (excluding FPL)	137.76	123.06	135.75	125.22
Rankings				
	2003	2004	2005	2006
FPL compared to companies comprising Industry Average:				
Florida Power & Light Company Rank	12	19	9	19
Total Ranked	63	76	66	70

Source: Edison Electric Institute (EEI)
Distribution System Average Interruption Duration Index (SAIDI) excluding Major Events

FPL 2007 Situational Assessment

Situational Assessment - 2007 (1 = most challenged)	Rank in Straight Electric Group	Rank in Regional Group	Rank in Large Utility Group
Percent Sales (MWh) Residential	1 / 28	1 / 4	1 / 7
Percent Sales (MWh) Other	1 / 28	1 / 4	1 / 7
Use per Customer	3 / 28	1 / 4	1 / 7
Change in Customers (%)	6 / 27	2 / 4	1 / 7
Change in Sales Vol (Rolling 5 Year CAGR)	11 / 26	1 / 4	2 / 7
Percent Generation Nuclear	11 / 28	1 / 4	4 / 7
Energy Losses / Total Energy Disposition	2 / 28	1 / 4	1 / 7
Accum. Dep./Gross Plant	6 / 28	1 / 4	3 / 7
Overall Merit Order	**1 / 28**	**1 / 4**	**1 / 7**

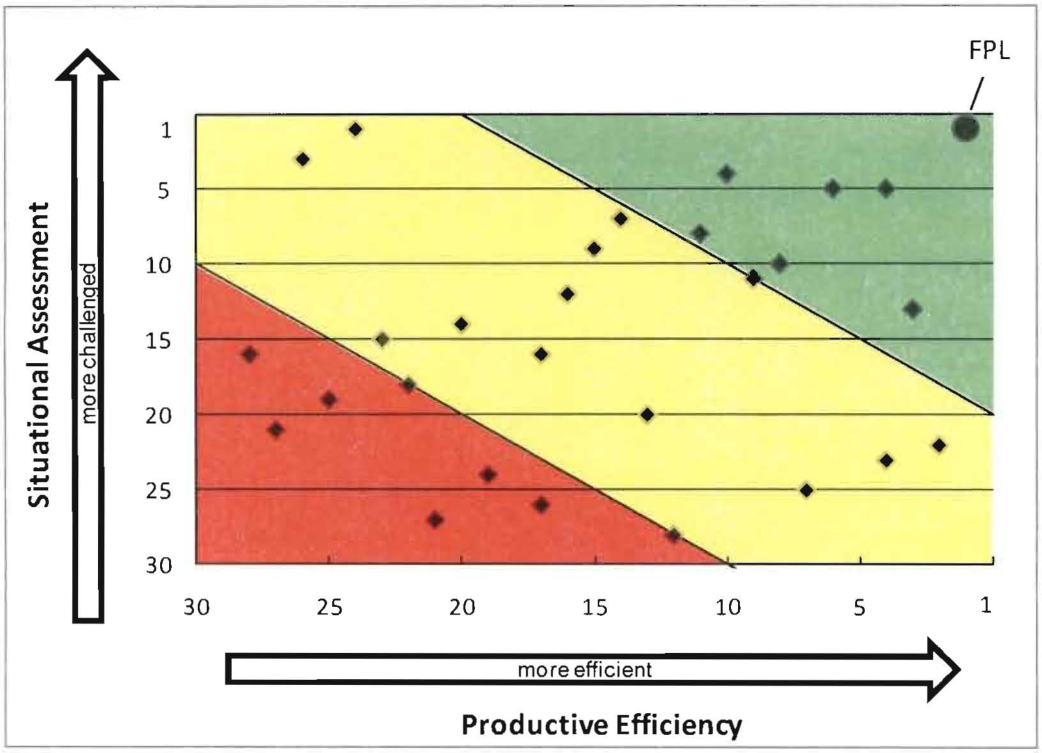
FPL 2007 Productive Efficiency

Productive Efficiency - 2007 (1 = highest performer)	Rank in Straight Electric Group	Rank in Regional Group	Rank in Large Utility Group
Non-Fuel Production O&M	4 / 28	1 / 4	1 / 7
Transmission O&M	7 / 28	1 / 4	1 / 7
Distribution O&M	7 / 28	1 / 4	2 / 7
A&G Expense	3 / 28	1 / 4	1 / 7
Customer Expense	13 / 28	1 / 4	2 / 7
Uncollectibles Expense	5 / 28	1 / 4	1 / 7
Days Sales Outstanding	13 / 25	3 / 4	3 / 7
Labor Efficiency	7 / 24	1 / 4	3 / 7
Total Non-Fuel O&M	2 / 28	1 / 4	1 / 7
Gross Asset Base	9 / 28	1 / 4	2 / 7
Additions to Plant / Cust Growth	4 / 26	2 / 4	1 / 5
Overall Merit Order	**1 / 28**	**1 / 4**	**1 / 7**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 174
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS John J. Reed (JJR-7)
DATE 10/23/09

Docket No. 080677-EI
FPL 2007 Combined Rankings
Exhibit JJR-8, Page 1 of 1

COMBINED 2007 SITUATIONAL ASSESSMENT AND OPERATIONAL EFFICIENCY RANKINGS



FLORIDA PUBLIC SERVICE COMMISSION	
DOCKET NO. 080677-EI & 090130-EI	EXHIBIT 175
COMPANY Florida Power & Light Co. (FPL) (Direct)	
WITNESS John J. Reed (JJR-8)	
DATE 10/23/09	

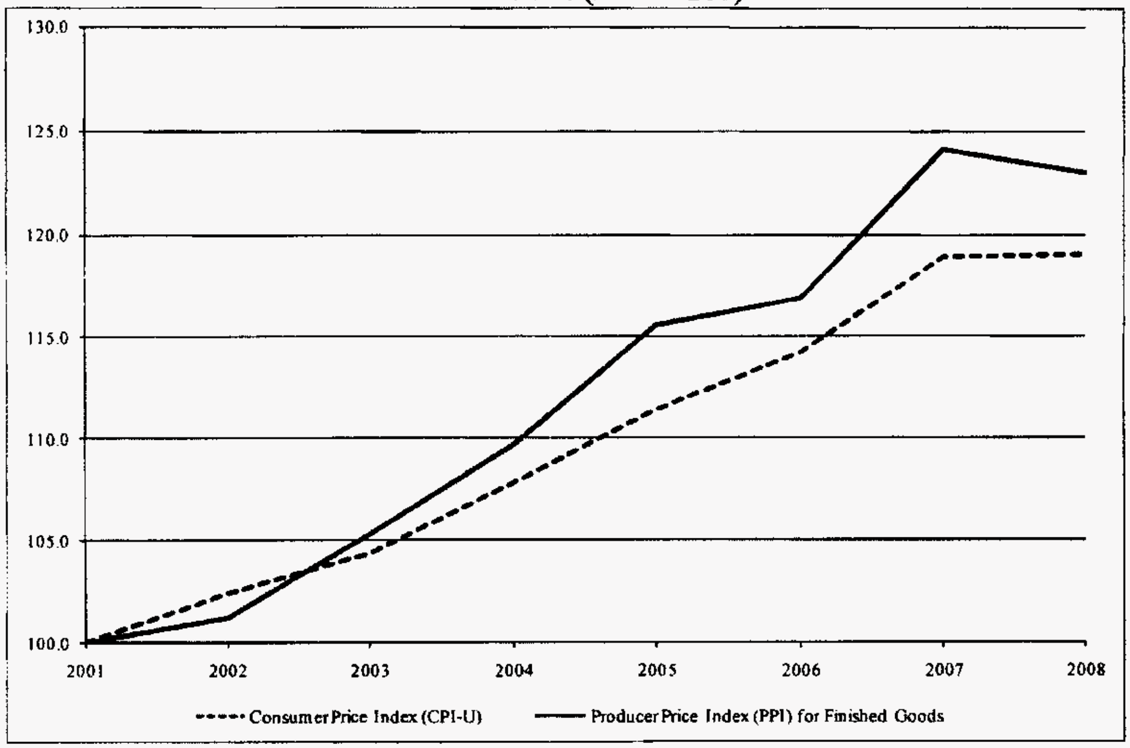
GREENHOUSE GAS EMISSIONS COMPARISON – 2007

Utility	2007 Net Generation (MWh)	Average Tons of CO_2 per MWh in 2007	Rank
Utilities within ±50% of Florida Power & Light Co.'s Net Generation (MWh)			
Florida Power & Light Company	**97,169,891**	**0.41**	1
Carolina Power & Light Company	58,357,199	0.55	2
Virginia Electric and Power Company	67,273,081	0.55	2
Georgia Power Company	87,901,842	0.77	3
Union Electric Company	50,315,718	0.79	4
Detroit Edison Company	52,855,118	0.85	5
Ohio Power Company	54,155,697	0.91	6
Alabama Power Company	69,826,121	0.92	7
PacifiCorp	54,533,393	0.95	8
Regional Florida Utilities			
Florida Power & Light Company	**97,169,891**	**0.41**	**1**
Progress Energy Florida	36,875,753	0.69	2
Tampa Electric Company	18,157,205	0.86	3
Gulf Power Company	16,657,267	0.94	4

Source: FERC Form 1, Environmental Protection Agency

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 176
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS John J. Reed (JJR-9)
DATE 10/23/09

Consumer Price Index – Urban Consumers & Producer Price Index - Finished Goods (2001 = 100)



Source: Bureau of Labor Statistics

Consumer Price Index – Urban Consumers and Producer Price Index - Finished Goods

	12-months through December							
	2001	2002	2003	2004	2005	2006	2007	2008
Consumer Price Index (CPI-U)	100.0	102.4	104.3	107.8	111.5	114.2	118.9	119.0
Producer Price Index (PPI) for Finished Goods	100.0	101.2	105.2	109.7	115.6	116.9	124.1	123.0

(2001 = 100)

Source: Bureau of Labor Statistics

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 177
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS John J. Reed (JJR-10)
DATE 10/23/09

PRODUCER PRICE INDEX FOR SELECT COMMODITIES

	Index Value							
	2001	2002	2003	2004	2005	2006	2007	2008
Consumer Price Index (CPI-U)	176.7	180.9	184.3	190.3	196.8	201.8	210.0	210.2
Producer Price Index (PPI) for Finished Goods	137.4	139.0	144.5	150.6	158.7	160.5	170.4	168.8
Concrete Products	153.0	152.5	154.8	166.6	183.4	198.2	205.8	214.5
Steel Mill Products	99.1	110.1	112.0	166.7	160.4	179.0	180.6	190.2
Copper and Brass Mill Shapes	149.4	147.0	164.1	212.6	278.4	402.0	389.8	295.1
Fabricated Iron & Steel Pipe, Tube, & Fittings	111.8	111.9	113.2	150.1	158.4	153.9	151.6	170.2
Cement	150.5	152.5	150.8	162.7	182.6	201.7	210.5	209.2
Iron Ore	96.3	95.0	96.5	103.0	119.0	127.9	129.5	145.2
Copper Ores*	77.4	80.2	110.2	181.9	253.3	387.8	381.2	288.6

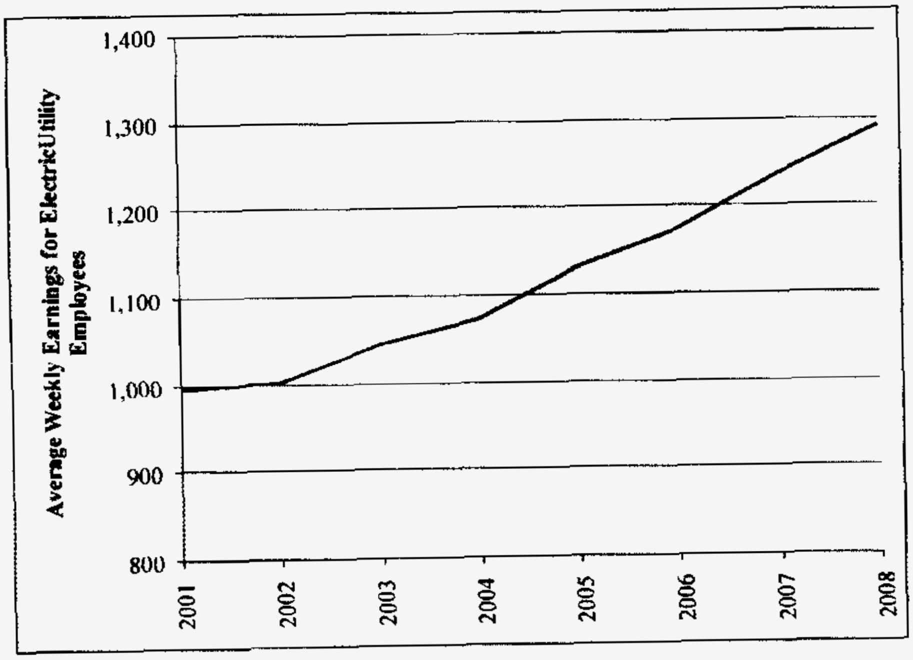
Note: Index Values as of December of each year listed;
Most recent 2008 data available for Copper Ore as of November 2008

	Percentage Change (%)								CAGR (%)
	2001	2002	2003	2004	2005	2006	2007	2008	2001-2008
Consumer Price Index (CPI-U)	1.6	2.4	1.9	3.3	3.4	2.5	4.1	0.1	2.5
Producer Price Index (PPI) for Finished Goods	-1.6	1.2	4.0	4.2	5.4	1.1	6.2	-0.9	3.0
Concrete Products	2.5	-0.3	1.5	7.6	10.1	8.1	3.8	4.2	4.9
Steel Mill Products	-6.1	11.1	1.7	48.8	-3.8	11.6	0.9	5.3	9.8
Copper and Brass Mill Shapes	-9.5	-1.6	11.6	29.6	31.0	44.4	-3.0	-24.3	10.2
Fabricated Iron & Steel Pipe, Tube, & Fittings	-0.6	0.1	1.2	32.6	5.5	-2.8	-1.5	12.3	6.2
Cement	1.0	1.3	-1.1	7.9	12.2	10.5	4.4	-0.6	4.8
Iron Ore	1.5	-1.3	1.6	6.7	15.5	7.5	1.3	12.1	6.0
Copper Ores*	-19.6	3.6	37.4	65.1	39.3	53.1	-1.7	-28.7	20.7

Note: Index Values as of December of each year listed;
Most recent 2008 data available for Copper Ore as of November 2008

Source: Bureau of Labor Statistics

AVERAGE WEEKLY EARNINGS FOR ELECTRIC UTILITY EMPLOYEES



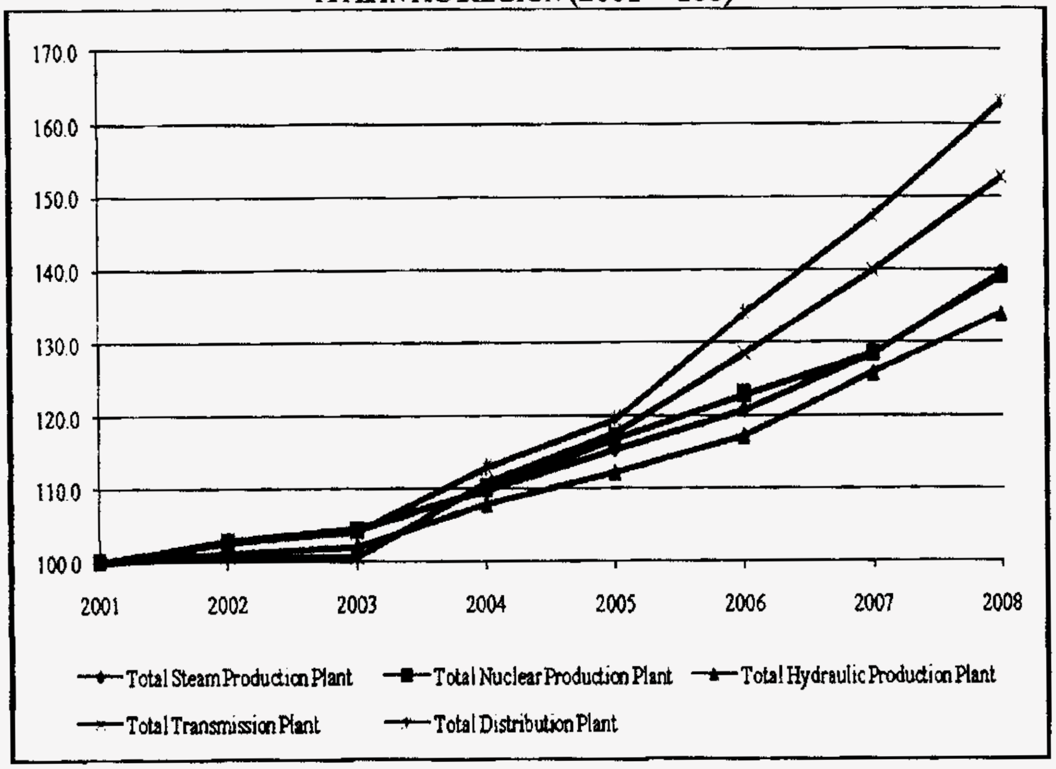
AVERAGE WEEKLY EARNINGS FOR ELECTRIC UTILITY EMPLOYEES

YEAR	VALUE
2001	996.05
2002	1,001.98
2003	1,045.22
2004	1,073.21
2005	1,131.80
2006	1,172.79
2007	1,236.06
2008	1,290.85

Source: Bureau of Labor Statistics

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 178
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS John J. Reed (JJR-11)
DATE 10/23/09

HANDY WHITMAN COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION – SOUTH ATLANTIC REGION (2001 = 100)



HANDY-WHITMAN INDEX OF ELECTRIC UTILITY CONSTRUCTION COSTS

	South Atlantic Region (2001 = 100)							
	2001	2002	2003	2004	2005	2006	2007	2008
Total Steam Production Plant	100.0	103.0	104.5	109.9	115.5	120.8	128.5	139.4
Total Nuclear Production Plant	100.0	102.7	104.3	110.1	117.0	123.1	128.6	139.0
Total Hydraulic Production Plant	100.0	101.2	102.2	107.8	112.2	117.3	126.0	133.9
Total Transmission Plant	100.0	100.8	100.5	110.8	117.8	128.6	139.9	152.7
Total Distribution Plant	100.0	102.8	104.1	113.0	119.7	134.1	147.3	162.8

Source: Handy-Whitman

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 179
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS John J. Reed (JJR-12)
DATE 10/23/09

Listed Below are the Document Nos. for the MFRs found in Dkt. 080677-EI:

Document No.	Description
02326-09	FPL (Olivera, Litchfield) - Vol 1 of 1, West County Energy Center Unit 3 schedules.
02327-09	FPL (Olivera, Litchfield) (Vol 1 of 5) MFRs for 2011 subsequent year adjustment schedules, summary and rate base schedules.
02328-09	Vol. 2
02329-09	Vol. 3
02330-09	Vol. 4
02331-09	Vol. 5
02326-09	FPL (Olivera, Litchfield) - Vol 1 of 1, West County Energy Center Unit 3 schedules.
02332-09	FPL (Olivera, Litchfield) - Vol 1 of 6, MFRs for 2010 test year schedules, summary and rate base schedules.
02333-09	Vol. 2 of 6
02334-09	Vol. 3 of 6
02335-09	Vol. 4 of 6
02336-09	Vol. 5 of 6
02337-09	Vol. 6 of 6
02817-09	FPL (Litchfield) - Vol 1 of 2, Supplemental 2009 MFR schedules, summary, rate base, and net operating income schedules.
02819-09	Vol 2 of 2

Listed Below are the Document Nos. for the MFRs found in Dkt. 090130-EI:

Document No.	Description
02279-09	Florida Power & Light Company [FPL] (Butler) - Witness C. Richard Clarke, Exh CRC-1, depreciation study, Vol 1 of 3.
02280-09	FPL (Butler) - Witness C. Richard Clarke, Exh CRC-1, depreciation study, Vol 2 of 3.
02281-09	FPL (Butler) - Witness, witness C. Richard Clarke, Exh CRC-1, depreciation study, Vol 3 of 3.
02282-09	FPL (Butler) - Depreciation study, calculated annual depreciation accruals related to electric plant as of 12/31/09; appendix, status reports for the years 2004 through 2007.
02283-09	FPL (Butler) - Vol 1 of 2, witness Kim Ousdahl, Exh KO-8, 2009 dismantlement study
02284-09	Vol 2 of 2

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 180
COMPANY Florida Power & Light Co. (FPL) (Direct)
WITNESS Various MFR's
DATE 10/23/09

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 181
COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Jacob Pous (Appendix 1)
DATE 08/31/09

JACOB POUS, P.E.

PRESIDENT, DIVERSIFIED UTILITY CONSULTANTS, INC.

B.S. INDUSTRIAL ENGINEERING M.S. MANAGEMENT

I graduated from the University of Missouri in 1972, receiving a Bachelor of Science Degree in Engineering, and I graduated with a Master of Science in Management from Rollins College in 1980. I have also completed a series of depreciation programs sponsored by Western Michigan University, and have attended numerous other utility related seminars.

Since my graduation from college, I have been continuously employed in various aspects of the utility business. I started with Kansas City Power & Light Co., working in the Rate Department, Corporate Planning and Economic Controls Department, and for a short time in a power plant. My responsibilities included preparation of testimony and exhibits for retail and wholesale rate cases. I participated in cost of service studies, a loss of load probability study, fixed charge analysis, and economic comparison studies. I was also a principal member of project teams that wrote, installed, maintained, and operated both a computerized series of depreciation programs and a computerized financial corporate model.

I joined the firm of R. W. Beck and Associates, an international consulting engineering firm with over 500 employees performing predominantly utility related work, in 1976 as an Engineer in the Rate Department of its Southeastern Regional Office. While employed with that firm, I prepared and presented rate studies for various electric, gas, water, and sewer systems, prepared and assisted in the preparation of cost of service studies, prepared depreciation and decommissioning analyses for wholesale and retail rate proceedings, and assisted in the development of power supply studies for electric systems. I resigned from that firm in November 1986 in order to co-found Diversified Utility Consultants, Inc. At the time of my resignation, I held the titles of Executive Engineer, Associate and Supervisor of Rates in the Austin office of R. W. Beck and Associates. I later founded P&L Concepts, Inc.

As a principal of the firm of Diversified Utility Consultants, Inc., I have presented and prepared numerous electric, gas, and water analyses in both retail and wholesale proceedings. These analyses have been performed on behalf of clients, including public utility commissions, throughout the United States and Canada. As president of P&L Concepts, Inc., I perform the same type of services as performed under Diversified Utility Consultants, Inc.

I have been involved in over 300 different utility rate proceedings, many of which have resulted in settlements prior to the presentation of testimony before regulatory bodies.

I am registered to practice as a Professional Engineer in the states of Florida, Texas, Mississippi, North Carolina, Arizona, New Mexico, Arkansas, and Oklahoma.

UTILITY RATE PROCEEDINGS IN WHICH TESTIMONY HAS BEEN PRESENTED BY JACOB POUS

ALASKA		
ALASKA REGULATORY COMMISSION		
JURISDICTION / COMPANY	*DOCKET NO.*	*TESTIMONY TOPIC*
Beluga Pipe Line Co.	P-04-81	Refundable Rates
Kenai Nikiski Pipeline	U-04-81	Rate Base
Beluga Pipe Line Co.	U-07-141	Depreciation
ARIZONA		
ARIZONA CORPORATION COMMISSION		
JURISDICTION / COMPANY	*DOCKET NO.*	*TESTIMONY TOPIC*
Citizens Utilities Co.	E-1032-93-111	Depreciation
ARKANSAS		
ARKANSAS PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	*DOCKET NO.*	*TESTIMONY TOPIC*
Reliant Energy ARKLA	01-0243-U	Depreciation
CALIFORNIA		
CALIFORNIA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	*DOCKET NO.*	*TESTIMONY TOPIC*
Pacific Gas & Electric Co.	Application No. 97-12-020	Depreciation, Net Salvage, and Amortization of True Up
Pacific Gas & Electric Co.	Application No. 02-11-017	Mass Property Salvage, Net Salvage, Mass Property Life, Life Analysis, Remaining Life, Depreciation
San Diego Gas & Electric Co.		Value of Power Plants
Southern California Edison Co.	Application 02-05-004	Depreciation, Net Salvage
CANADA		
ALBERTA ENERGY AND UTILITIES BOARD		
JURISDICTION / COMPANY	*DOCKET NO.*	*TESTIMONY TOPIC*
AltaLink Management/ Transalta Utilities Corp	App. Nos. 1279345 and 1279347	Depreciation
Epcor Distribution, Inc.	App No. 1306821	Depreciation
Enmax Corporation	App No. 1306818	Depreciation
Transalta Utilities Corporation	TFO Tariff Appl. 1287507	Depreciation

UtiliCorp Networks Canada (Alberta) Ltd.	App. No. 1250392	Depreciation
Atco Electric	App. No. 1275494	Depreciation
ALBERTA PUBLIC UTILITIES BOARD		
Alberta Power Limited	E 91095	Depreciation
Alberta Power Limited	E 97065	Depreciation
Canadian Western Natural Gas Co. Limited		Depreciation
Centra Gas Alberta Inc.		Depreciation
Edmonton Power Co.	E 97065	Depreciation
Edmonton Power Generation, Inc.	1999/2000	GUR Compliance, Depreciation
Northwestern Utilities Limited	E 91044	Depreciation
NOVA Gas Transmission Ltd.	RE95006	Depreciation
TransAlta Utilities Corporation	E 91093	Depreciation
TransAlta Utilities Corporation	E 97065	Depreciation
TransAlta Utilities Corporation	App No. 200051	Gain on Sale
NORTHWEST TERRITORIES PUBLIC UTILITIES BOARD		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Northwest Territories Power Corporation	1995/96 and 1996-97	Depreciation
Northwest Territories Power Corporation	2001	Depreciation
COURTS		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
112th Judicial District Court of Texas	5093	Ratemaking principles, Calculation of damages
253rd Judicial District Court of Texas	45,615	Ratemaking principles, Level of Bond
126th Judicial District Court of Texas	91-1519	Ratemaking principles, Level of Bond
172 Judicial District Court of Texas		Franchise Fees
United States Bankruptcy Court Eastern District of Texas	93-10408S	Level of Harm, Ratemaking, Equity for Creditors
3rd Judicial District Court of Texas		Adequacy of Notice
DISTRICT OF COLUMBIA		
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Washington Gas Light Co.	768	Depreciation

FLORIDA		
FLORIDA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	*DOCKET NO.*	*TESTIMONY TOPIC*
Progress Energy Florida, Inc.	050078-EL	Depreciation
Florida Power & Light Co.	790380-EU	Territorial Dispute
FEDERAL ENERGY REGULATORY COMMISSION		
JURISDICTION / COMPANY	*DOCKET NO.*	*TESTIMONY TOPIC*
Alabama Power Co.	ER83-369	Depreciation
Connecticut Municipal Elect. Energy Coop v Connecticut Light & Power Co.	EL83-14	Decommissioning
Florida Power & Light Co.	ER84-379	Depreciation, Decommissioning
Florida Power & Light Co.	ER93-327-000	Transmission access
Georgia Power Co.	ER76-587	Rate Base
Georgia Power Co.	ER79-88	Depreciation
Georgia Power Co.	ER81-730	Coal Fuel Stock Inventory, Depreciation
ISO New England, Inc.	ER07-166-000	Depreciation
Maine Yankee Atomic Power Co.	ER84-344-001	Depreciation, Decommissioning
Maine Yankee Atomic Power Co.	ER88-202	Decommissioning
Pacific Gas & Electric	ER80-214	Depreciation
Public Service of Indiana	ER95-625-000, ER95-626-000 & ER95-039-000	Depreciation, Dismantlement
Southern California Edison Co.	ER81-177	Depreciation
Southern California Edison Co.	ER82-427	Depreciation, Decommissioning
Southern California Edison Co.	ER84-75	Depreciation, Decommissioning
Southwestern Public Service Co.	EL 89-50	Depreciation, Decommissioning
System Energy Resource, Inc.	ER95-1042-000	Depreciation, Decommissioning
Vermont Electric Power Co.	ER83 342000 & 343000	Decommissioning
Virginia Electric and Power Co.	ER78-522	Depreciation, Rate Base
INDIANA		
INDIANA UTILITY REGULATORY COMMISSION		
JURISDICTION / COMPANY	*DOCKET NO.*	*TESTIMONY TOPIC*
Indianapolis Water Co.	39128	Depreciation
Indiana Michigan Power Co.	39314	Depreciation, Decommissioning
KANSAS		

KANSAS CORPORATION COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Arkansas Louisiana Gas Co.	181,200-U	Depreciation
United Cities Gas Co.	181,940-U	Depreciation
LOUISIANA		
LOUISIANA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Louisiana Power & Light Co.	U-16945	Nuclear Prudence, Depreciation
CITY OF NEW ORLEANS		
Entergy New Orleans, Inc.	UD-00-2	Rate Base, Depreciation
MASSACHUSETTS		
MASSACHUSETTS TELECOMMUNICATIONS AND ENERGY		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Bay State Gas	D.T.E.-0527	Depreciation
National Grid/KeySpan	07-30	Quality of Service
MISSISSIPPI		
MISSISSIPPI PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Mississippi Power Co.	U-3739	Cost of Service, Rate Base, Depreciation
MONTANA		
MONTANA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Montana Power Co. (Gas)	90.6.39	Depreciation
Montana Power Co. (Electric)	90.3.17	Depreciation, Decommissioning
Montana Power Co. (Electric and Gas)	95.9.128	Depreciation
Montana-Dakota Utilities	D2007.7.79	Depreciation
NEVADA		
NEVADA PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	DOCKET NO.	TESTIMONY TOPIC
Nevada Power Co.	81-602, 81-685 Cons.	Depreciation
Nevada Power Co.	83-667, Consolidated	Depreciation
Nevada Power Co.	91-5032	Depreciation, Decommissioning
Nevada Power Co.	03-10002	Depreciation
Nevada Power Company	06-06051	Depreciation, Life Spans, Decommissioning Costs, Deferred Accounting
	06-11022	General Rate Case

Sierra Pacific Power Co.	83-955	Depreciation (Electric, Gas, Water, Common)
Sierra Pacific Power Co.	86-557	Depreciation, Decommissioning
Sierra Pacific Power Co.	89-516, 517, 518	Depreciation, Decommissioning (Elec., Gas, Water, Common)
Sierra Pacific Power Co.	91-7079, 80, 81	Depreciation, Decommissioning (Elec., Gas, Water, Common)
Sierra Pacific Power Co.	03-12002	Allowable level of plant in service
Sierra Pacific Power Co.	05-10004	Depreciation
Sierra Pacific Power Co.	05-10006	Depreciation
Sierra Pacific Gas Company	06-07010	Depreciation, Generating Plant Life Spans, Decommissioning Costs, Carrying Costs
Sierra Pacific Power Co.	07-12001	Depreciation, CWC
Southwest Gas Corporation	93-3025 & 93-3005	Depreciation
Southwest Gas Corporation	04-3011	Depreciation
Southwest Gas Company	07-09030	Depreciation

NORTH CAROLINA

NORTH CAROLINA UTILITIES COMMISSION

JURISDICTION / COMPANY	*DOCKET NO.*	*TESTIMONY TOPIC*
North Carolina Natural Gas	G-21, Sub 177	Cost of Service, Rate Design, Depreciation

OKLAHOMA

OKLAHOMA CORPORATION COMMISSION

JURISDICTION / COMPANY	*DOCKET NO.*	*TESTIMONY TOPIC*
Arkansas Oklahoma Gas Corporation	PUD 200300088	CWC, Legal expenses, Factoring, Cost Allocation, Depreciation
Oklahoma Natural Gas Co.	PUD 980000683	Depreciation, Calculation Procedure, Depreciation on CWIP
Public Service Co. of Oklahoma	PUD 960000214	Depr., Interim Activity, Net Salvage, Mass Prop., Rate Calc. Technique
Reliant Energy ARKLA	PUD 200200166	Depreciation, Net Salvage, Software Amortization
Public Service Company of Oklahoma	PUD 200600285	Depreciation
Public Service Company of Oklahoma	PUD 200800144	Depreciation

TEXAS		
TEXAS PUBLIC UTILITY COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Centerpoint Energy Houston Electric LLC	29526	Stranded Costs
Centerpoint Energy Houston Electric LLC	36918	Hurricane Recovery Costs
Central Power & Light Co.	6375	Depreciation, Rate Base, Cost of Service
Central Power & Light Co.	8439	Fuel Factor
Central Power & Light Co.	8646	Rate Base, Excess Capacity, Depreciation, Rate Design, Rate Case Expense
Central Power & Light Co.	9561	Depr., Excess Capacity, Cost of Service, Rate Base, Taxes
Central Power & Light Co.	11371	Economic Development Rate
Central Power & Light Co.	12820	Nuclear Fuel & Process, OPEB, Pension, Factoring, Depr.
Central Power & Light Co.	14965	Depr., Cash Working Capital, Pension, OPEB, Factoring, Demonstration & selling expense, non-nuclear decommissioning
Central Power & Light Co.	22352	Depreciation
Central Telephone & United Telephone Co. of Texas D/B/A Sprint	17809	Rate case expenses
City of Fredericksburg	7661	Territorial Dispute
El Paso Electric Co.	9165	Depreciation
Entergy Gulf States, Inc.	16705	Depr., Prepayments, Payroll Exp.e, Pension Exp., OPEB's, CWC, Transfer of T&D Depr.
Entergy Gulf States, Inc.	21111	Reconcilable fuel costs
Entergy Gulf States, Inc.	21384	Fuel surcharge
Entergy Gulf States, Inc.	23000	Fuel surcharge
Entergy Gulf States, Inc.	22356	Unbundling, Competition, Cost of Service
Entergy Gulf States, Inc.	23550	Reconcilable fuel costs
Entergy Gulf States, Inc.	24336	Price to Beat
Entergy Gulf States, Inc.	24460	Implement PUC Subst.R.25.41(f)(3)(D)
Entergy Gulf States, Inc.	24469	Delay of Deregulation

Entergy Gulf States, Inc.	24953	Interim Fuel Surcharge
Entergy Gulf States, Inc.	26612	Fuel Surcharge
Entergy Gulf States, Inc.	28504	Interim Fuel Surcharge
Entergy Gulf States, Inc.	28818	Cert. for Independent Organization
Entergy Gulf States, Inc.	29408	Fuel Reconciliation
Entergy Gulf States, Inc.	30163	Interim Fuel Surcharge
Entergy Gulf States, Inc.	31315	Incremental Purchase Capacity Rider
Entergy Gulf States, Inc.	31544	Transition to Competition Cost
Entergy Gulf States, Inc.	32465	Interim Fuel Surcharge
Entergy Gulf States, Inc.	32710	River Bend 30%, Explicit Capacity, Imputed Capacity, IPCR, SGSF Operating Costs and Depreciation Recovery, Option Costs
Entergy Gulf States, Inc.	33687	Transition to Competition
Entergy Gulf States, Inc.	33966	Interim Fuel Surcharge
Entergy Gulf States, Inc.	32907	Hurricane Reconstruction
Entergy Gulf States, Inc.	34724	IPCR
Entergy Gulf States, Inc.	34800	JSP, Depreciation, Decommissioning, Amortization, CWC, Franchise Fees, Rate Case Exp.
Gulf States Utilities Co.	5560	Depreciation, Fuel Cost Factor
Gulf States Utilities Co.	5820	Fuel Cost, Capacity Factors, Heat Rates
Gulf States Utilities Co.	6525	Depreciation, Rate Case Expenses
Gulf States Utilities Co.	7195 & 6755	Depr., Interim Cash Study, Excess Capacity, Rate Case Exp.
Gulf States Utilities Co.	8702	Rate Case Expenses, Depreciation
Gulf States Utilities Co.	10,894	Fuel Reconciliation, Rate Case Expenses
Gulf States Utilities Co. & Entergy Corporation	11292	Acquisition Adjustment Regulatory Plan, Base Rate, Rate Case Exp.
Gulf States Utilities Co. & Entergy Corporation	12423	North Star Steel Agreement
Gulf States Utilities Co. & Entergy Corporation	12852	Depreciation, OPEB, Pensions, Cash Working Capitol, Other Cost of Service, and Rate Base Items
Houston Light & Power Co.	6765	Depreciation, Production Plant, Early Retirement
Lower Colorado River Authority	8400	Rate Design
Magic Valley Electric Cooperative,	10820	Cost of Service, Financial Integrity,

Inc.		Rate Case Expenses
Oncor	35717	Depreciation, Self-Insurance, Payroll, Automated Meters, Regulatory Assets, PHFU
Southwestern Bell Telephone Co.	18513	Rate case expenses
Southwestern Electric Power Co.	3716	Depreciation
Southwestern Electric Power Co.	4628	Depreciation
Southwestern Electric Power Co.	5301	Depreciation, Fuel Charges, Franchise Fees
Southwestern Electric Power Co.	24449	Fuel Factor Component of Price to Beat Rates
Southwestern Electric Power Co.	24468	Delay of Deregulation
Southwestern Public Service Co.	11520	Depreciation, Cash Working Capital, Rate Case Expenses
Southwestern Public Service Co.	32766	Depreciation Expense Revenue Requirements
Southwestern Public Service Co.	35763	Depreciation
Texas-New Mexico Power Co.	9491	Avoided Cost, Rate Case Expenses
Texas-New Mexico Power Co.	10200	Jurisdictional Separation, Cost Allocation, Rate Case Expenses
Texas-New Mexico Power Co.	17751	Rate Case Expenses
Texas-New Mexico Power Co.	36025	Depreciation
Texas Utilities Electric Co.	5640	Franchise Fees
Texas Utilities Electric Co.	9300	Depreciation, Rate Base, Cost of Service, Fuel Charges, Rate Case Expenses
Texas Utilities Electric Co.	11735	Cost Allocation, Rate Design, Rate Case Expenses
Texas Utilities Electric Co.	18490	Depreciation Reclassification
West Texas Utilities Co.	7510	Depreciation, Decommissioning, Rate Base, Cost of Service, Rate Design, Rate Case Expenses
West Texas Utilities Co.	10035	Fuel Reconciliation, Rate Case Expenses
West Texas Utilities Co.	13369	Depreciation, Payroll, Pension, OPEB'S, cash working capital, fuel inventory, cost allocation, other.
West Texas Utilities Co.	22354	Depreciation
TEXAS RAILROAD COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Atmos Energy Corporation	9530	Gas Cost, Gas Purchases, Price

		Mitigation, Rate Case Expense
Atmos Energy Corporation	9670	CWC, Depreciation, Expenses, Shared Services, Taxes Other Than FIT, Excess Return
Atmos Energy Corporation	9695	Rate Case Expense
Atmos Energy Corporation	9762	Depreciation, O&M Expense
Atmos Energy Corporation	9732	Rate Case Expense
Atmos Energy Corporation	9869	Full Revenue Requirements
CenterPoint Energy Entex-City of Tyler	9364	Capital investment, Affiliates
CenterPoint Energy Entex	9791	Rate Base, Cost Allocation, Affiliate Expenses, Depreciation Net Salvage, Call Center, Litigation, Uncollectibles, Post Test Year Adjustments
Energas Co.	5793	Depreciation
Energas Co. v. Westar Transmissions Co.	5168 & 4892 Cons.	Cost of Service, Refunds, Contracts, Depreciation
Energas Co.	8205	Cost of Service, Rate Base, Depreciation, Affiliate Transactions, Sale/Leaseback, Losses, Income Taxes
Energas Co.	9002-9135	Depr., Pension, Cash Working Capital, OPEB's, Rate Design
Lone Star Gas Co.	8664	Cash Working Capital, Depreciation Expense, Gain on Sale of Plant, OPEB's, Rate Case Expenses
Rio Grande Valley Gas Co.	7604	Depreciation
Southern Union Gas Co.	2738, 2958, 3002, 3018, 3019 Cons.	Cost of Service, Rate Design, Depreciation
Southern Union Gas Co.	6968 Interim & Cons.	Affiliate Transactions, Rate Base, Income Taxes, Revenues, Cost of Service, Conservation, Depreciation
Southern Union Gas Co.	8033 Consolidated	Acquisition Adj., Depr., Accumulated Provisions for Depr., Distribution Plant, Cost of Gas Clause, Rate Case Expenses
Southern Union Gas Co.	8878	Depreciation, Cash Working Capital, Gain on Sale of Building, Rate Case Expenses, Rate Design
TXU Lone Star Pipeline	8976	Depreciation, Net Salvage, Cash Working Capital, ALG vs. ELG

TXU Gas Distribution	9145-9147	Depreciation, Cash Working Capital, Revenues, Gain on Sale of Assets, Clearing Accounts, Over Recovery of Clearing Accounts, SFAS 106, Wages and Salaries, Merger Costs, Intra System Allocation, Zero Intercept, Customer Weighting Factor, Rate Design
TXU-Gas Distribution	9400	Depreciation, Net Salvage, Cash Working Capital, Affiliate Transactions, Software Amortization, Securitization, O&M Expenses, Safety Compliance
Westar Transmissions Co.	5787	Depreciation, Rate Base, Cost of Service, Rate Design, Contract Issues, Revenues, Losses, Income Taxes
TEXAS WATER COMMISSION		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
City of Harlingen-Certificate for Convenience & Necessity	8480C/8485C/ 8512C	Rate Impact for CCN
City of Round Rock	8599/8600M	Rate Discrimination, Cost of Service
Devers Canal System	8388-M	Affil. Transactions, O&M Exp., Return, Allocation, Acquisition Adj., Retroactive Ratemaking, Rate Case Exp., Depr.
Devers Canal System	30102-M	Cost of Service, Rate base, Ratemaking Principles, Affil. Trans.
Southern Utilities Co.	7371-R	Affiliate Transactions, Cost of Service
Scenic Oaks Water Supply Corporation	8097-G	Affiliate Transactions, Cost of Service, Rate base, Cost of Capital, Rate Design, Depreciation
Sharyland Water Supply vs. United Irrigation District	8293-M	Rate Discrimination, Cost of Service, Rate Case Exp.
Travis County Water Control & Improv. District No. 20		Cost of Service
EL PASO PUBLIC UTILITY REGULATION BOARD		
JURISDICTION / COMPANY	***DOCKET NO.***	***TESTIMONY TOPIC***
Southern Union Gas Co.	1991	Depreciation, Calculation Procedure
Southern Union Gas Co.	1997	Depreciation, Calculation Procedure
Southern Union Gas Co.	GUD 8878 – 1998	Depreciation, Cash Working Capital, Rate Design, Rate Case Expenses
Texas Gas Services Co.	2007	Revenue Requirements

UTAH		
UTAH PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	*DOCKET NO.*	*TESTIMONY TOPIC*
PacifiCorp	98-2035-03	Production Plant Net Salvage, Production Life Span, Interim Additions, Mass Property, Depreciation
Rocky Mountain Power	07-035-13	Depreciation
Questar	05-057-T01	Conservation Enabling Tariff Adjustment Option and Accounting Orders
WYOMING		
WYOMING PUBLIC SERVICE COMMISSION		
JURISDICTION / COMPANY	*DOCKET NO.*	*TESTIMONY TOPIC*
PacifiCorp	20000-ER-00-162	Rate Parity

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080677-EI & 090130-EI EXHIBIT 182

COMPANY Office of Public Counsel (OPC) (Direct)

WITNESS Jacob Pous (JP-1)

DATE 08/31/09

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED DEPRECIATION ADJUSTMENTS BASED ON DEPRECIATION STUDY PLANT AS OF DECEMBER 31, 2009

Line No.	Description	FPL Proposal	OPC Recommended	OPC Adjustment
		(a)	(b)	(c)
1	Steam	$99,476,072	$58,368,083	-$41,107,989
2	Nuclear	$93,658,545	$70,260,192	-$23,398,353
3	Combined Cycle	$204,079,249	$169,920,569	-$34,158,680
4	Other Production	$10,133,223	$3,802,831	-$6,330,392
5	Total Production	$407,347,089	$302,351,675	-$104,995,414
6	Future Units	$132,892,978	$112,943,071	-$19,949,907
7	Capital Recovery	$78,555,754	$78,555,754	$0
8	Special Production	$211,448,732	$191,498,825	-$19,949,907
9	Total Production	$618,795,821	$493,850,500	-$124,945,321
10	Transmission	$94,218,582	$69,214,289	-$25,004,293
11	Distribution	$337,640,039	$249,241,349	-$88,398,690
12	General	$14,968,698	$12,643,989	-$2,324,709
13	Total Mass Property	$446,827,319	$331,099,626	-$115,727,693
14	Total Depreciation	$1,065,623,140	$824,950,126	-$240,673,014
15	Reserve Amortization	$0	-$311,340,104	-$311,340,104
16	Total Annual Impact	$1,065,623,140	$513,610,022	-$552,013,118

SOURCES AND REFERENCES

Column (a)	: FPL Exhibit CRC-1 page 49.
Column (b) Line 1	: OPC Exhibit__(JP-1) page 8.
Column (b) Line 2	: OPC Exhibit__(JP-1) page 10.
Column (b) Line 3	: OPC Exhibit__(JP-1) page 15.
Column (b) Line 4	: OPC Exhibit__(JP-1) page 16.
Column (b) Line 5	: Summation of Lines 1-4.
Column (b) Line 6	: OPC Exhibit__(JP-1) page 17.
Column (b) Line 7	: FPL Exhibit CRC-1 page 49.
Column (b) Line 8	: Summation of Lines 6 and 7.
Column (b) Line 9	: Summation of Lines 5 and 8.
Column (b) Lines 10 & 11	: OPC Exhibit__(JP-1) page 18.
Column (b) Line 12	: OPC Exhibit__(JP-1) page 19.
Column (b) Line 13	: Summation of Lines 10-12.
Column (b) Line 14	: FPL Exhibit CRC-1 page 53 divided by 4 years.
Column (b) Line 15	: Summation of Lines 10-12.
Column (b) Line 16	: Line 14 plus Line 15.

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED STEAM PRODUCTION PLANT DEPRECIATION RATES

Account	Balance 31-Dec-09	Net Salvage %	Net Salvage Amount	Reserve 31-Dec-09	Unrecovered Balance	Unadjusted Rem. Life	Interim Ret. Rate	Adjusted Rem. Life	Annual Accrual	Accrual Rate	FPL Request	OPC Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Cutler Common		(a)x(b)		(a)-(b)-(c)				(e)/(h)	(i)/(a)		(i)-(k)
311	$5,973,901	-0.47%	-$28,077	$6,074,928	-$72,950	10.5	0.0041	10.27	-$7,103	-0.12%	$18,968	-$26,071
312	$817,291	-2.65%	-$21,658	$692,141	$146,808	10.5	0.0075	10.09	$14,550	1.78%	$21,558	-$7,008
314	$1,234,614	1.67%	$20,618	$1,356,414	-$142,418	10.5	0.0077	10.08	-$14,129	-1.14%	$0	-$14,129
315	$1,058,634	-3.26%	-$34,511	$1,023,308	$69,837	10.5	0.0078	10.07	$6,935	0.66%	$15,859	-$8,924
316	$627,886	-1.01%	-$6,342	$671,750	-$37,522	10.5	0.0083	10.04	-$3,737	-0.60%	$0	-$3,737
Total	$9,712,326		-$69,971	$9,818,541	-$36,244	10.5			-$3,484	-0.04%	$56,385	-$59,869
	Cutler 5											
311	$423,784	-0.47%	-$1,992	$402,046	$23,730	10.5	0.0041	10.27	$2,311	0.55%	$4,166	-$1,855
312	$5,530,327	-2.65%	-$146,554	$5,441,757	$235,124	10.5	0.0075	10.09	$23,303	0.42%	$69,390	-$46,087
314	$5,999,465	1.67%	$100,191	$5,038,174	$861,100	10.5	0.0077	10.08	$85,427	1.42%	$96,231	-$10,804
315	$2,340,096	-3.26%	-$76,287	$2,230,375	$186,008	10.5	0.0078	10.07	$18,472	0.79%	$38,863	-$20,391
316	$233,543	-1.01%	-$2,359	$94,141	$141,761	10.5	0.0083	10.04	$14,120	6.05%	$14,777	-$657
Total	$14,527,215		-$127,000	$13,206,493	$1,447,722	10.5			$143,631	0.99%	$223,427	-$79,796
	Cutler 6											
311	$412,315	-0.47%	-$1,938	$390,736	$23,517	10.5	0.0041	10.27	$2,290	0.56%	$4,346	-$2,056
312	$17,878,953	-2.65%	-$473,792	$9,717,420	$8,635,325	10.5	0.0075	10.09	$855,830	4.79%	$994,427	-$138,597
314	$8,588,788	1.67%	$143,433	$8,178,602	$266,753	10.5	0.0077	10.08	$26,464	0.31%	$40,738	-$14,274
315	$3,055,523	-3.26%	-$99,610	$3,115,214	$39,919	10.5	0.0078	10.07	$3,964	0.13%	$30,373	-$26,409
316	$123,506	-1.01%	-$1,247	$70,178	$54,575	10.5	0.0083	10.04	$5,436	4.40%	$5,979	-$543
	$30,059,085		-$433,155	$21,472,150	$9,020,090	10.5			$893,983	2.97%	$1,075,863	-$181,880
Total Cutler	$54,298,626		-$630,126	$44,497,184	$10,431,568				$1,034,130	1.90%	$1,355,675	-$321,545

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED STEAM PRODUCTION PLANT DEPRECIATION RATES

	Balance	Net Salvage		Reserve	Unrecovered	Unadjusted	Interim	Adjusted	Annual	Accrual	FPL	OPC
Account	31-Dec-09	%	Amount	31-Dec-09	Balance	Rem. Life	Ret. Rate	Rem. Life	Accrual	Rate	Request	Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Manatee Common		(a)x(b)		(a)-(b)-(c)				(e)/(h)	(i)/(a)		(i)-(k)
311	$96,350,477	-0.47%	-$452,847	$66,182,177	$30,621,147	17.5	0.0041	16.87	$1,815,124	1.88%	$3,423,959	-$1,608,835
312	$2,032,783	-2.65%	-$53,869	$2,351,080	-$264,428	17.5	0.0075	16.35	-$16,173	-0.80%	$0	$0
314	$11,281,165	1.67%	$188,395	$7,381,751	$3,711,019	17.5	0.0077	16.32	$227,391	2.02%	$395,105	-$167,714
315	$9,282,558	-3.26%	-$302,611	$7,480,218	$2,104,951	17.5	0.0078	16.31	$129,059	1.39%	$302,558	-$173,499
316	$2,505,571	-1.01%	-$25,306	$2,163,270	$367,607	17.5	0.0083	16.23	$22,650	0.90%	$43,085	-$20,435
Total	$121,452,554		-$646,238	$85,558,496	$36,540,296	17.5			$2,178,051	1.79%	$4,164,707	-$1,970,483
Manatee Unit 1												
311	$7,311,443	-0.47%	-$34,364	$6,056,272	$1,289,535	17.5	0.0041	16.87	$76,440	1.05%	$160,093	-$83,653
312	$125,082,972	-2.65%	-$3,314,699	$88,747,199	$39,650,472	17.5	0.0075	16.35	$2,425,105	1.94%	$4,986,604	-$2,561,499
314	$64,713,219	1.67%	$1,080,711	$43,658,860	$19,973,648	17.5	0.0077	16.32	$1,223,876	1.89%	$2,118,431	-$894,555
315	$10,668,482	-3.26%	-$347,793	$8,484,911	$2,531,364	17.5	0.0078	16.31	$155,203	1.45%	$335,111	-$179,908
316	$3,065,530	-1.01%	-$30,962	$2,300,726	$795,766	17.5	0.0083	16.23	$49,031	1.60%	$94,561	-$45,530
Total	$210,841,646		-$2,647,106	$149,247,968	$64,240,784	17.5			$3,929,654	1.86%	$7,694,800	-$3,765,146
Manatee Unit 2												
311	$5,286,225	-0.47%	-$24,845	$4,349,570	$961,500	17.5	0.0041	16.87	$56,995	1.08%	$118,563	-$61,568
312	$116,916,975	-2.65%	-$3,098,300	$65,449,562	$54,565,713	17.5	0.0075	16.35	$3,337,352	2.85%	$6,504,955	-$3,167,603
314	$61,991,571	1.67%	$1,035,259	$47,866,381	$13,089,931	17.5	0.0077	16.32	$802,079	1.29%	$1,411,121	-$609,042
315	$7,832,693	-3.26%	-$255,346	$6,159,150	$1,928,889	17.5	0.0078	16.31	$118,264	1.51%	$252,241	-$133,977
316	$2,217,093	-1.01%	-$22,393	$1,713,083	$526,403	17.5	0.0083	16.23	$32,434	1.46%	$62,330	-$29,896
Total	$194,244,557		-$2,365,624	$125,537,746	$71,072,435	17.5			$4,347,124	2.24%	$8,349,210	-$4,002,086
Total Manatee	$526,538,757		-$5,658,969	$360,344,210	$171,853,516				$10,454,829	1.99%	$20,208,717	-$9,737,715

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED STEAM PRODUCTION PLANT DEPRECIATION RATES

Account	Balance 31-Dec-09 (a)	Net Salvage % (b)	Net Salvage Amount (c) (a)x(b)	Reserve 31-Dec-09 (d)	Unrecovered Balance (e) (a)-(b)-(c)	Unadjusted Rem. Life (f)	Interim Ret. Rate (g)	Adjusted Rem. Life (h)	Annual Accrual (i) (e)/(h)	Accrual Rate (j) (i)/(a)	FPL Request (k)	OPC Adjustment (l) (i)-(k)
Martin Steam Plant												
311	$236,118,421	-0.47%	-$1,109,757	$199,736,765	$37,491,413	21.5	0.0041	20.55	$1,824,400	0.77%	$4,748,635	-$2,924,235
312	$4,159,551	-2.65%	-$110,228	$3,968,319	$301,460	21.5	0.0075	19.77	$15,248	0.37%	$63,988	-$48,740
314	$26,277,902	1.67%	$438,841	$20,072,953	$5,766,108	21.5	0.0077	19.72	$292,399	1.11%	$627,676	-$335,277
315	$7,648,705	-3.26%	-$249,348	$6,646,272	$1,251,781	21.5	0.0078	19.7	$63,542	0.83%	$191,355	-$127,813
316	$2,788,671	-1.01%	-$28,166	$2,658,816	$158,021	21.5	0.0083	19.58	$8,071	0.29%	$23,544	-$15,473
Total	$276,993,250		-$1,058,657	$233,083,125	$44,968,782	21.5			$2,203,660	0.80%	$5,655,198	-$3,451,538
Martin Pipeline												
312	$370,940	-2.65%	-$9,830	$370,942	$9,828	21.5	0.0075	19.77	$497	0.13%	$4,121	-$3,624
Total	$370,940		-$9,830	$370,942	$9,828	21.5			$497	0.13%	$4,121	-$3,624
Martin Unit 1												
311	$15,381,834	-0.47%	-$72,295	$14,323,981	$1,130,148	21.5	0.0041	20.55	$54,995	0.36%	$180,122	-$125,127
312	$138,526,135	-2.65%	-$3,670,943	$117,549,375	$24,647,703	21.5	0.0075	19.77	$1,246,722	0.90%	$3,769,275	-$2,522,553
314	$76,392,977	1.67%	$1,275,763	$58,217,327	$16,899,887	21.5	0.0077	19.72	$856,992	1.12%	$1,849,645	-$992,653
315	$20,097,362	-3.26%	-$655,174	$18,525,818	$2,226,718	21.5	0.0078	19.7	$113,031	0.56%	$393,089	-$280,058
316	$2,580,596	-1.01%	-$26,064	$2,316,994	$289,666	21.5	0.0083	19.58	$14,794	0.57%	$37,251	-$22,457
Total	$252,978,904		-$3,148,713	$210,933,495	$45,194,122	21.5			$2,286,535	0.90%	$6,229,382	-$3,942,847
Martin Unit 2												
311	$11,123,219	-0.47%	-$52,279	$10,371,694	$803,804	21.5	0.0041	20.55	$39,115	0.35%	$128,802	-$89,687
312	$143,922,027	-2.65%	-$3,813,934	$110,427,775	$37,308,186	21.5	0.0075	19.77	$1,887,111	1.31%	$5,088,444	-$3,201,333
314	$62,777,097	1.67%	$1,048,378	$43,619,337	$18,109,382	21.5	0.0077	19.72	$918,326	1.46%	$1,954,223	-$1,035,897
315	$17,891,013	-3.26%	-$583,247	$14,174,047	$4,300,213	21.5	0.0078	19.7	$218,285	1.22%	$572,538	-$354,253
316	$2,200,607	-1.01%	-$22,226	$1,984,288	$238,545	21.5	0.0083	19.58	$12,183	0.55%	$31,261	-$19,078
Total	$237,913,963		-$3,423,308	$180,577,141	$60,760,130	21.5			$3,075,019	1.29%	$7,775,268	-$4,700,249
Total Martin	$768,257,057		-$7,640,508	$624,964,703	$150,932,862				$7,565,711	0.98%	$19,663,969	-$12,098,258

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED STEAM PRODUCTION PLANT DEPRECIATION RATES

Account	Balance 31-Dec-09	Net Salvage %	Net Salvage Amount	Reserve 31-Dec-09	Unrecovered Balance	Unadjusted Rem. Life	Interim Ret. Rate	Adjusted Rem. Life	Annual Accrual	Accrual Rate	FPL Request	OPC Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Pt. Everglades Steam Plant			(a)x(b)		(a)-(b)-(c)				(e)/(h)	(i)/(a)		(i)-(k)
Pt. Everglades Common												
311	$24,463,219	-0.47%	-$114,977	$19,474,779	$5,103,417	10.5	0.0041	10.27	$496,925	2.03%	$598,639	-$101,714
312	$2,831,767	-2.65%	-$75,042	$1,063,962	$1,842,847	10.5	0.0075	10.09	$182,641	6.45%	$206,004	-$23,363
314	$4,830,537	1.67%	$80,670	$2,708,107	$2,041,760	10.5	0.0077	10.08	$202,556	4.19%	$212,056	-$9,500
315	$6,006,107	-3.26%	-$195,799	$4,948,543	$1,253,363	10.5	0.0078	10.07	$124,465	2.07%	$172,131	-$47,666
316	$2,005,034	-1.01%	-$20,251	$1,561,640	$463,645	10.5	0.0083	10.04	$46,180	2.30%	$51,932	-$5,752
Total	$40,136,664		-$325,399	$29,757,031	$10,705,032	10.5			$1,052,766	2.62%	$1,240,762	-$187,996
Pt. Everglades Unit 1												
311	$1,840,592	-0.47%	-$8,651	$1,413,369	$435,874	10.5	0.0041	10.27	$42,441	2.31%	$52,289	-$9,848
312	$34,942,212	-2.65%	-$925,969	$30,785,069	$5,083,112	10.5	0.0075	10.09	$503,777	1.44%	$777,851	-$274,074
314	$17,391,669	1.67%	$290,441	$13,273,559	$3,827,669	10.5	0.0077	10.08	$379,729	2.18%	$409,242	-$29,513
315	$7,962,611	-3.26%	-$259,581	$3,317,503	$4,904,689	10.5	0.0078	10.07	$487,059	6.12%	$540,353	-$53,294
316	$503,103	-1.01%	-$5,081	$155,795	$352,389	10.5	0.0083	10.04	$35,099	6.98%	$39,100	-$4,001
Total	$62,640,187		-$908,841	$48,945,295	$14,603,733	10.5			$1,448,106	2.31%	$1,818,835	-$370,729
Pt. Everglades Unit 2												
311	$1,732,046	-0.47%	-$8,141	$1,073,033	$667,154	10.5	0.0041	10.27	$64,961	3.75%	$74,053	-$9,092
312	$39,657,434	-2.65%	-$1,050,922	$33,026,508	$7,681,848	10.5	0.0075	10.09	$761,333	1.92%	$1,069,561	-$308,228
314	$17,170,811	1.67%	$286,753	$9,730,189	$7,153,869	10.5	0.0077	10.08	$709,709	4.13%	$760,450	-$50,741
315	$9,508,129	-3.26%	-$309,965	$5,518,068	$4,300,026	10.5	0.0078	10.07	$427,014	4.49%	$495,192	-$68,178
316	$549,842	-1.01%	-$5,553	$191,522	$363,873	10.5	0.0083	10.04	$36,242	6.59%	$39,438	-$3,196
Total	$68,618,262		-$1,087,828	$49,539,320	$20,166,770	10.5			$1,999,259	2.91%	$2,438,694	-$439,435
Pt. Everglades Unit 3												
311	$5,811,192	-0.47%	-$27,313	$799,291	$5,039,214	10.5	0.0041	10.27	$490,673	8.44%	$511,057	-$20,384
312	$78,802,927	-2.65%	-$2,088,278	$44,970,182	$35,921,023	10.5	0.0075	10.09	$3,560,062	4.52%	$4,211,675	-$651,613
314	$25,278,630	1.67%	$422,153	$10,888,684	$13,967,793	10.5	0.0077	10.08	$1,385,694	5.48%	$1,461,444	-$75,750
315	$13,169,884	-3.26%	-$429,338	$7,492,120	$6,107,102	10.5	0.0078	10.07	$606,465	4.60%	$709,219	-$102,754
316	$402,449	-1.01%	-$4,065	$225,808	$180,706	10.5	0.0083	10.04	$17,999	4.47%	$18,818	-$819
Total	$123,465,082		-$2,126,840	$64,376,085	$61,215,837	10.5			$6,060,892	4.91%	$6,912,213	-$851,321
Pt. Everglades Unit 4												
311	$787,556	-0.47%	-$3,702	$568,650	$222,608	10.5	0.0041	10.27	$21,676	2.75%	$24,880	-$3,204
312	$97,124,127	-2.65%	-$2,573,789	$55,145,849	$44,552,067	10.5	0.0075	10.09	$4,415,468	4.55%	$5,213,411	-$797,943
314	$23,073,436	1.67%	$385,326	$11,544,450	$11,143,660	10.5	0.0077	10.08	$1,105,522	4.79%	$1,174,273	-$68,751
315	$15,289,269	-3.26%	-$498,430	$8,876,213	$6,911,486	10.5	0.0078	10.07	$686,344	4.49%	$805,051	-$118,707
316	$172,080	-1.01%	-$1,738	$145,870	$27,948	10.5	0.0083	10.04	$2,784	1.62%	$3,223	-$439
Total	$136,446,468		-$2,692,333	$76,281,032	$62,857,769	10.5			$6,231,793	4.57%	$7,220,838	-$989,045
Total Pt. Evrgd	$431,306,663		-$7,141,241	$268,898,763	$169,549,141				$16,792,816	3.89%	$19,631,342	-$2,838,526

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED STEAM PRODUCTION PLANT DEPRECIATION RATES

Account	Balance 31-Dec-09 (a)	Net Salvage % (b)	Net Salvage Amount (c)	Reserve 31-Dec-09 (d)	Unrecovered Balance (e)	Unadjusted Rem. Life (f)	Interim Ret. Rate (g)	Adjusted Rem. Life (h)	Annual Accrual (i)	Accrual Rate (j)	FPL Request (k)	OPC Adjustment (l)
Sanford Steam Plant			(a)x(b)		(a)-(b)-(c)				(e)/(h)	(i)/(a)		(i)-(k)
Sanford Unit 3												
311	$4,701,046	-0.47%	-$22,095	$3,657,094	$1,066,047	10.5	0.0041	10.27	$103,802	2.21%	$123,202	-$19,400
312	$10,679,201	-2.65%	-$282,999	$10,049,469	$912,731	10.5	0.0075	10.09	$90,459	0.85%	$176,144	-$85,685
314	$13,119,005	1.67%	$219,087	$4,491,872	$8,408,046	10.5	0.0077	10.08	$834,132	6.36%	$909,191	-$75,059
315	$4,585,245	-3.26%	-$149,479	$1,729,645	$3,005,079	10.5	0.0078	10.07	$298,419	6.51%	$334,704	-$36,285
316	$399,034	-1.01%	-$4,030	$354,395	$48,669	10.5	0.0083	10.04	$4,848	1.21%	$5,883	-$1,035
Total	$33,483,531		-$239,516	$20,282,475	$13,440,572	10.5			$1,331,659	3.98%	$1,549,124	-$217,465
Total Sanford	$33,483,531		-$239,516	$20,282,475	$13,440,572				$1,331,659	3.98%	$1,549,124	-$217,465
Scherer Steam Plant												
Scherer Coal Cars												
312	$34,174,990	-2.65%	-$905,637	$32,938,994	$2,141,633	38.5	0.0075	32.94	$65,016	0.19%	$272,689	-$207,673
Total	$34,174,990		-$905,637	$32,938,994	$2,141,633	38.5			$65,016	0.19%	$272,689	-$207,673
Scherer Common												
311	$38,262,666	-0.47%	-$179,835	$25,274,737	$13,167,764	38.5	0.0041	35.46	$371,341	0.97%	$798,633	-$427,292
312	$21,879,850	-2.65%	-$579,816	$14,155,294	$8,304,372	38.5	0.0075	32.94	$252,106	1.15%	$581,938	-$329,832
314	$4,044,832	1.67%	$67,549	$3,203,638	$773,645	38.5	0.0077	32.79	$23,594	0.58%	$49,567	-$25,973
315	$1,235,563	-3.26%	-$40,279	$993,051	$282,791	38.5	0.0078	32.72	$8,643	0.70%	$21,736	-$13,093
316	$3,160,922	-1.01%	-$31,925	$2,367,100	$825,747	38.5	0.0083	32.35	$25,525	0.81%	$52,764	-$27,239
Total	$68,583,833		-$764,307	$45,993,820	$23,354,320	38.5			$681,209	0.99%	$1,504,638	-$823,429
Scherer Common Unit 3 & 4												
311	$2,955,496	-0.47%	-$13,891	$2,518,453	$450,934	38.5	0.0041	18.6	$24,244	0.82%	$31,392	-$7,148
312	$17,081,036	-2.65%	-$452,647	$11,531,752	$6,001,931	38.5	0.0075	17.4	$344,939	2.02%	$426,951	-$82,012
314	$335,873	1.67%	$5,609	$285,101	$45,163	38.5	0.0077	17	$2,657	0.79%	$2,980	-$323
315	$292,934	-3.26%	-$9,550	$212,548	$89,936	38.5	0.0078	18.1	$4,969	1.70%	$6,369	-$1,400
Total	$20,665,339		-$470,479	$14,547,854	$6,587,964	38.5			$376,808	1.82%	$467,692	-$90,884
Scherer Unit 4												
311	$64,076,617	-0.47%	-$301,160	$38,754,282	$25,623,495	38.5	0.0041	35.46	$722,603	1.13%	$1,535,168	-$812,565
312	$276,755,766	-2.65%	-$7,334,028	$172,000,115	$112,089,679	38.5	0.0075	32.94	$3,402,844	1.23%	$7,818,631	-$4,415,787
314	$116,669,482	1.67%	$1,948,380	$67,876,049	$46,845,053	38.5	0.0077	32.79	$1,428,638	1.22%	$2,884,899	-$1,456,261
315	$22,875,511	-3.26%	-$745,742	$15,693,441	$7,927,812	38.5	0.0078	32.72	$242,293	1.06%	$551,748	-$309,455
316	$4,337,834	-1.01%	-$43,812	$2,879,628	$1,502,018	38.5	0.0083	32.35	$46,430	1.07%	$90,985	-$44,555
Total	$484,715,210		-$6,476,361	$297,203,515	$193,988,056	38.5			$5,842,808	1.21%	$12,881,431	-$7,038,623
Total Scherer	$608,139,372		-$8,616,784	$390,684,183	$226,071,973				$6,965,841	1.15%	$15,126,450	-$8,160,609

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED STEAM PRODUCTION PLANT DEPRECIATION RATES

Account	Balance 31-Dec-09	Net Salvage %	Net Salvage Amount	Reserve 31-Dec-09	Unrecovered Balance	Unadjusted Rem. Life	Interim Ret. Rate	Adjusted Rem. Life	Annual Accrual	Accrual Rate	FPL Request	OPC Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
SJRPP Steam Plant			(a)x(b)		(a)-(b)-(c)				(e)/(h)	(i)/(a)		(i)-(k)
SJRPP Coal & Limestone												
311	$3,835,845	-0.47%	-$18,028	$2,348,432	$1,505,441	37.5	0.0041	18.6	$80,938	2.11%	$96,407	-$15,469
312	$31,307,987	-2.65%	-$829,662	$20,733,572	$11,404,077	37.5	0.0075	17.4	$655,407	2.09%	$884,944	-$229,537
315	$3,776,787	-3.26%	-$123,123	$2,942,226	$957,684	37.5	0.0078	17	$56,334	1.49%	$77,460	-$21,126
316	$306,801	-1.01%	-$3,099	$248,280	$61,620	37.5	0.0083	18.1	$3,404	1.11%	$4,554	-$1,150
Total	$39,227,420		-$973,912	$26,272,510	$13,928,822	37.5			$796,083	2.03%	$1,063,365	-$267,282
SJRPP Coal Cars												
312	$2,725,310	-2.65%	-$72,221	$2,672,650	$124,881	37.5	0.0075	32.23	$3,875	0.14%	$19,878	-$16,003
Total	$2,725,310		-$72,221	$2,672,650	$124,881	37.5			$3,875	0.14%	$19,878	-$16,003
SJRPP Common												
311	$43,483,249	-0.47%	-$204,371	$22,008,384	$21,679,236	37.5	0.0041	34.62	$626,206	1.44%	$1,329,160	-$702,954
312	$4,841,873	-2.65%	-$128,310	$2,114,111	$2,856,072	37.5	0.0075	32.23	$88,615	1.83%	$194,405	-$105,790
314	$3,464,477	1.67%	$57,857	$1,649,923	$1,756,697	37.5	0.0077	32.09	$54,743	1.58%	$111,178	-$56,435
315	$7,914,407	-3.26%	-$258,010	$4,659,423	$3,512,994	37.5	0.0078	32.02	$109,712	1.39%	$243,016	-$133,304
316	$2,173,083	-1.01%	-$21,948	$1,463,580	$731,451	37.5	0.0083	31.66	$23,103	1.06%	$45,479	-$22,376
Total	$61,877,089		-$554,782	$31,895,421	$30,536,450	37.5			$902,379	1.46%	$1,923,238	-$1,020,859
SJRPP Gypsum & Ash												
311	$2,079,386	-0.47%	-$9,773	$1,437,419	$651,740	37.5	0.0041	34.62	$18,826	0.91%	$42,912	-$24,086
312	$17,574,970	-2.65%	-$465,737	$14,372,745	$3,667,962	37.5	0.0075	32.23	$113,806	0.65%	$321,134	-$207,328
315	$53,709	-3.26%	-$1,751	$32,364	$23,096	37.5	0.0078	32.02	$721	1.34%	$1,625	-$904
316	$112,764	-1.01%	-$1,139	$81,078	$32,825	37.5	0.0083	31.66	$1,037	0.92%	$2,333	-$1,296
Total	$19,820,829		-$478,400	$15,923,606	$4,375,623	37.5			$134,389	0.68%	$368,004	-$233,615
SJRPP Unit 1												
311	$12,636,281	-0.47%	-$59,391	$6,330,456	$6,365,216	37.5	0.0041	34.62	$183,859	1.46%	$390,867	-$207,008
312	$100,097,129	-2.65%	-$2,652,574	$49,273,277	$53,476,426	37.5	0.0075	32.23	$1,659,213	1.66%	$3,721,876	-$2,062,663
314	$35,745,341	1.67%	$596,947	$15,820,181	$19,328,213	37.5	0.0077	32.09	$602,313	1.69%	$1,213,181	-$610,868
315	$15,979,993	-3.26%	-$520,948	$9,748,498	$6,752,443	37.5	0.0078	32.02	$210,882	1.32%	$468,881	-$257,999
316	$2,799,432	-1.01%	-$28,274	$1,525,561	$1,302,145	37.5	0.0083	31.66	$41,129	1.47%	$82,574	-$41,445
Total	$167,258,176		-$2,664,239	$82,697,973	$87,224,442	37.5			$2,697,396	1.61%	$5,877,379	-$3,179,983
SJRPP Unit 2												
311	$7,487,417	-0.47%	-$35,191	$4,920,104	$2,602,504	37.5	0.0041	34.62	$75,173	1.00%	$169,117	-$93,944
312	$65,614,711	-2.65%	-$1,738,790	$42,156,598	$25,196,903	37.5	0.0075	32.23	$781,784	1.19%	$1,924,591	-$1,142,807
314	$24,131,830	1.67%	$403,002	$14,806,356	$8,922,472	37.5	0.0077	32.09	$278,045	1.15%	$579,661	-$301,616
315	$9,798,705	-3.26%	-$319,438	$7,694,036	$2,424,107	37.5	0.0078	32.02	$75,706	0.77%	$197,046	-$121,340
316	$1,622,572	-1.01%	-$16,388	$1,132,958	$506,002	37.5	0.0083	31.66	$15,982	0.99%	$34,823	-$18,841
Total	$108,655,235		-$1,706,805	$70,710,052	$39,651,988	37.5			$1,226,691	1.13%	$2,905,238	-$1,678,547
Total SJRPP	$399,564,059		-$6,450,359	$230,172,212	$175,842,206				$5,760,814	1.44%	$12,157,102	-$6,396,288

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED STEAM PRODUCTION PLANT DEPRECIATION RATES

Account	Balance 31-Dec-09	Net Salvage %	Net Salvage Amount	Reserve 31-Dec-09	Unrecovered Balance	Unadjusted Rem. Life	Interim Ret. Rate	Adjusted Rem. Life	Annual Accrual	Accrual Rate	FPL Request	OPC Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Turkey Point Steam Plant			(a)x(b)		(a)-(b)-(c)				(e)/(h)	(i)/(a)		(i)-(k)
Turkey Point Common												
311	$9,974,936	-0.47%	-$46,882	$8,508,390	$1,513,428	10.5	0.0041	10.27	$147,364	1.48%	$188,940	-$41,576
312	$2,839,101	-2.65%	-$75,236	$1,662,708	$1,251,629	10.5	0.0075	10.09	$124,046	4.37%	$145,609	-$21,563
314	$1,590,774	1.67%	$26,566	$1,113,631	$450,577	10.5	0.0077	10.08	$44,700	2.81%	$47,399	-$2,699
315	$3,671,052	-3.26%	-$119,676	$3,146,875	$643,853	10.5	0.0078	10.07	$63,938	1.74%	$93,777	-$29,839
316	$1,189,610	-1.01%	-$12,015	$932,326	$269,299	10.5	0.0083	10.04	$26,823	2.25%	$29,629	-$2,806
Total	$19,265,473		-$227,244	$15,363,930	$4,128,787	10.5			$406,871	2.11%	$505,354	-$98,483
Turkey Point Unit 1												
311	$2,269,026	-0.47%	-$10,664	$1,657,463	$622,227	10.5	0.0041	10.27	$60,587	2.67%	$70,186	-$9,599
312	$71,130,814	-2.65%	-$1,884,967	$46,737,167	$26,278,614	10.5	0.0075	10.09	$2,604,422	3.66%	$3,175,700	-$571,278
314	$25,082,846	1.67%	$418,884	$15,434,221	$9,229,741	10.5	0.0077	10.08	$915,649	3.65%	$964,711	-$49,062
315	$5,105,015	-3.26%	-$166,423	$2,992,130	$2,279,308	10.5	0.0078	10.07	$226,346	4.43%	$270,562	-$44,216
316	$729,112	-1.01%	-$7,364	$484,001	$252,475	10.5	0.0083	10.04	$25,147	3.45%	$26,751	-$1,604
Total	$104,316,813		-$1,650,535	$67,304,982	$38,662,366	10.5			$3,832,151	3.67%	$4,507,910	-$675,759
Turkey Point Unit 2												
311	$2,585,697	-0.47%	-$12,153	$1,848,067	$749,783	10.5	0.0041	10.27	$73,007	2.82%	$83,509	-$10,502
312	$54,758,844	-2.65%	-$1,451,109	$32,817,674	$23,392,279	10.5	0.0075	10.09	$2,318,363	4.23%	$2,736,884	-$418,521
314	$25,717,422	1.67%	$429,481	$12,610,713	$12,677,228	10.5	0.0077	10.08	$1,257,662	4.89%	$1,315,564	-$57,902
315	$8,029,283	-3.26%	-$261,755	$2,586,297	$5,704,741	10.5	0.0078	10.07	$566,509	7.06%	$625,087	-$58,578
316	$401,764	-1.01%	-$4,058	$328,312	$77,510	10.5	0.0083	10.04	$7,720	1.92%	$9,385	-$1,665
Total	$91,493,010		-$1,299,594	$50,191,063	$42,601,541	10.5			$4,223,260	4.62%	$4,770,429	-$547,169
Total Trky Pt	$215,075,296		-$3,177,372	$132,859,975	$85,392,693				$8,462,282	3.93%	$9,783,693	-$1,321,411
Total Steam	$3,036,663,361		-$39,554,874	$2,072,703,705	$1,003,514,530				$58,402,122	1.92%	$99,476,072	-$41,073,950

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED NUCLEAR PRODUCTION PLANT DEPRECIATION RATES

Account	Balance 31-Dec-09	Net Salvage %	Net Salvage Amount	Reserve 31-Dec-09	Unrecovered Balance	Unadjusted Rem. Life	Interim Ret. Rate	Adjusted Rem. Life	Annual Accrual	Accrual Rate	FPL Request	OPC Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Nuclear Production Plant			(a)x(b)		(a)-(b)-(c)				(e)/(h)	(i)/(a)		(i)-(k)
St. Lucie Nuclear Plant												
321	$343,585,840	0.0%	$0	$188,941,755	$154,644,085	30.5	0.0017	29.71	$5,205,119	1.51%	$7,397,355	-$2,192,236
322	$78,860,497	-0.3%	-$197,151	$27,134,974	$51,922,674	30.5	0.0044	28.45	$1,825,050	2.31%	$2,030,488	-$205,438
323	$673,278	0.0%	$0	$3,128,795	-$2,455,517	30.5	0.0088	26.41	-$92,977	-13.81%	$0	-$92,977
324	$31,186,353	-0.1%	-$18,712	$20,419,506	$10,785,559	30.5	0.0011	29.99	$359,639	1.15%	$684,826	-$325,187
325	$23,912,279	0.0%	$0	$13,085,814	$10,826,465	30.5	0.0027	29.24	$370,262	1.55%	$400,714	-$30,452
Total	$478,218,247		-$215,863	$252,710,844	$225,723,266				$7,667,093	1.60%	$10,513,383	-$2,846,290
St. Lucie Unit 1												
321	$162,204,629	0.0%	$0	$95,748,242	$66,456,387	30.5	0.0017	29.71	$2,236,836	1.38%	$3,968,425	-$1,731,589
322	$484,411,228	-0.3%	-$1,211,028	$218,892,777	$266,729,479	30.5	0.0044	28.45	$9,375,377	1.94%	$12,486,836	-$3,111,459
323	$60,630,329	0.0%	$0	$46,868,841	$13,761,488	30.5	0.0088	26.41	$521,071	0.86%	$657,344	-$136,273
324	$78,893,831	-0.1%	-$47,336	$50,499,654	$28,441,513	30.5	0.0011	29.99	$948,367	1.20%	$2,137,453	-$1,189,086
325	$10,597,550	0.0%	$0	$8,460,696	$2,136,854	30.5	0.0027	29.24	$73,080	0.69%	$94,042	-$20,962
Total	$796,737,567		-$1,258,364	$420,470,210	$377,525,721				$13,154,730	1.65%	$19,344,100	-$6,189,370
St. Lucie Nuclear Plant												
321	$252,865,619	0.0%	$0	$162,270,170	$90,595,449	30.5	0.0017	29.71	$3,049,325	1.21%	$5,094,733	-$2,045,408
322	$701,058,570	-0.3%	-$1,752,646	$286,627,567	$416,183,649	30.5	0.0044	28.45	$14,628,599	2.09%	$17,212,635	-$2,584,036
323	$81,377,496	0.0%	$0	$57,593,310	$23,784,186	30.5	0.0088	26.41	$900,575	1.11%	$1,276,398	-$375,823
324	$160,196,421	-0.1%	-$96,118	$99,173,648	$61,118,891	30.5	0.0011	29.99	$2,037,976	1.27%	$4,149,839	-$2,111,863
325	$20,747,433	0.0%	$0	$14,209,133	$6,538,300	30.5	0.0027	29.24	$223,608	1.08%	$244,194	-$20,586
Total	$1,216,245,539		-$1,848,764	$619,873,828	$598,220,475				$20,840,083	1.71%	$27,977,799	-$7,137,716
Total St. Lucie	$2,491,201,353		-$3,322,992	$1,293,054,882	$1,201,469,463				$41,661,906	1.67%	$57,835,282	-$16,173,376

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED NUCLEAR PRODUCTION PLANT DEPRECIATION RATES

Account	Balance 31-Dec-09	Net Salvage %	Net Salvage Amount	Reserve 31-Dec-09	Unrecovered Balance	Unadjusted Rem. Life	Interim Ret. Rate	Adjusted Rem. Life	Annual Accrual	Accrual Rate	FPL Request	OPC Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Turkey Point Nuclear Plant			(a)x(b)		(a)-(b)-(c)				(e)/(h)	(i)/(a)		(i)-(k)
Turkey Point Common												
321	$280,753,503	0.0%	$0	$150,713,277	$130,040,226	23.5	0.0017	23.03	$5,646,558	2.01%	$6,337,601	-$691,043
322	$53,315,074	-0.3%	-$133,288	$29,938,630	$23,509,732	23.5	0.0044	22.29	$1,054,721	1.98%	$1,194,585	-$139,864
323	$21,037,774	0.0%	$0	$4,547,145	$16,490,629	23.5	0.0088	21.07	$782,659	3.72%	$809,137	-$26,478
324	$48,095,983	-0.1%	-$28,858	$29,249,282	$18,875,559	23.5	0.0011	23.2	$813,602	1.69%	$1,301,200	-$487,598
325	$27,575,932	0.0%	$0	$14,222,976	$13,352,956	23.5	0.0027	22.75	$586,943	2.13%	$600,175	-$13,232
Total	$430,778,266		-$162,145	$228,671,310	$202,269,101				$8,884,483	2.06%	$10,242,698	-$1,358,215
Turkey Point Unit 3												
321	$51,568,621	0.0%	$0	$26,021,875	$25,546,746	23.5	0.0017	23.03	$1,109,281	2.15%	$1,376,031	-$266,750
322	$272,369,788	-0.3%	-$680,924	$148,765,102	$124,285,610	23.5	0.0044	22.29	$5,288,749	1.94%	$6,538,674	-$1,249,925
323	$41,927,456	0.0%	$0	$27,910,607	$14,016,849	23.5	0.0088	21.07	$596,462	1.42%	$848,191	-$251,729
324	$97,160,938	-0.1%	-$58,297	$69,116,708	$28,102,527	23.5	0.0011	23.2	$1,195,852	1.23%	$2,395,375	-$1,199,523
325	$2,722,122	0.0%	$0	$2,132,477	$589,645	23.5	0.0027	22.75	$25,091	0.92%	$28,495	-$3,404
Total	$465,748,925		-$739,221	$273,946,769	$192,541,377				$8,215,436	1.76%	$11,186,766	-$2,971,330
Turkey Point Unit 4												
321	$83,711,978	0.0%	$0	$38,231,060	$45,480,918	23.5	0.0017	23.03	$1,974,855	2.36%	$2,250,520	-$275,665
322	$272,718,161	-0.3%	-$681,795	$143,701,832	$129,698,124	23.5	0.0044	22.29	$5,818,669	2.13%	$6,555,177	-$736,508
323	$76,858,753	0.0%	$0	$46,357,990	$30,500,763	23.5	0.0088	21.07	$1,447,592	1.88%	$1,718,411	-$270,819
324	$145,562,903	-0.1%	-$87,338	$94,298,628	$51,351,613	23.5	0.0011	23.2	$2,213,432	1.52%	$3,823,960	-$1,610,528
325	$3,912,597	0.0%	$0	$2,915,692	$996,905	23.5	0.0027	22.75	$43,820	1.12%	$45,731	-$1,911
Total	$582,764,392		-$769,133	$325,505,202	$258,028,323				$11,498,368	1.97%	$14,393,799	-$2,895,431
Total Turkey Pon	$1,479,291,583		-$1,670,499	$828,123,281	$652,838,801				$28,598,286	1.93%	$35,823,263	-$7,224,977
Total Nuclear	$3,970,492,936		-$4,993,491	$2,121,178,163	$1,854,308,264				$70,260,192	1.77%	$93,658,545	-$23,398,353

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED COMBINED CYCLE PRODUCTION PLANT DEPRECIATION RATES

Account	Balance 31-Dec-09	Net Salvage %	Net Salvage Amount	Reserve 31-Dec-09	Unrecovered Balance	Unadjusted Rem. Life	Interim Ret. Rate	Adjusted Rem. Life	Annual Accrual	Accrual Rate	FPL Request	OPC Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Lauderdale Combined Cycle Plant			(a)x(b)		(a)-(b)-(c)				(e)/(h)	(i)/(a)		(i)-(k)
Lauderdale Common												
341	$74,718,137	0.00%	$0	$50,852,187	$23,865,950	10.5	0.0005	10.47	$2,279,460	3.05%	$3,889,663	-$1,610,203
342	$9,414,115	0.00%	$0	$5,588,631	$3,825,484	10.5	0.0045	10.25	$373,218	3.96%	$533,025	-$159,807
343	$35,523,207	0.00%	$2,261,195	$4,724,080	$28,537,932	10.5	0.0015	9.47	$3,014,027	8.48%	$3,265,779	-$251,752
344	$1,646,834	0.00%	$0	$916,636	$730,198	10.5	0.0002	10.49	$69,609	4.23%	$146,478	-$76,869
345	$12,033,813	0.00%	$0	$7,746,021	$4,287,792	10.5	0.0001	10.49	$408,750	3.40%	$505,979	-$97,229
346	$930,984	0.00%	$0	$571,382	$359,602	10.5	0.001	10.44	$34,445	3.70%	$44,307	-$9,862
Total	$134,267,090		$2,261,195	$70,398,937	$61,606,958	10.5			$6,179,510	4.60%	$8,385,231	-$2,205,721
Lauderdale Unit 4												
341	$4,790,462	0.00%	$0	$4,026,215	$764,247	10.5	0.0005	10.47	$72,994	1.52%	$159,912	-$86,918
342	$665,939	0.00%	$0	$399,889	$266,050	10.5	0.0045	10.25	$25,956	3.90%	$33,408	-$7,452
343	$144,270,473	0.00%	$2,982,471	$83,930,531	$57,357,471	10.5	0.0015	9.07	$6,325,982	4.38%	$5,996,444	$329,538
344	$27,385,918	0.00%	$0	$15,841,475	$11,544,443	10.5	0.0002	10.49	$1,100,519	4.02%	$1,453,117	-$352,598
345	$27,691,585	0.00%	$0	$18,566,718	$9,124,867	10.5	0.0001	10.49	$869,863	3.14%	$1,074,731	-$204,868
346	$2,602,044	0.00%	$0	$1,902,133	$699,911	10.5	0.001	10.44	$67,041	2.58%	$93,627	-$26,586
Total	$207,406,421		$2,982,471	$124,666,961	$79,756,989	10.5			$8,462,356	4.08%	$8,811,239	-$348,883
					-$597,403							
Lauderdale Unit 5												
341	$2,978,287	0.00%	$0	$2,163,032	$815,255	10.5	0.0005	10.47	$77,866	2.61%	$140,468	-$62,602
342	$665,779	0.00%	$0	$388,555	$277,224	10.5	0.0045	10.25	$27,046	4.06%	$34,488	-$7,442
343	$129,534,725	0.00%	$7,338,670	$72,370,213	$49,825,842	10.5	0.0015	9.89	$5,038,043	3.89%	$5,810,106	-$772,063
344	$29,242,014	0.00%	$0	$16,922,352	$12,319,662	10.5	0.0002	10.49	$1,174,420	4.02%	$1,544,312	-$369,892
345	$22,925,535	0.00%	$0	$15,692,247	$7,233,288	10.5	0.0001	10.49	$689,541	3.01%	$857,118	-$167,577
346	$1,767,721	0.00%	$0	$1,240,205	$527,516	10.5	0.001	10.44	$50,528	2.86%	$73,835	-$23,307
Total	$187,114,061		$7,338,670	$108,776,604	$70,998,787	10.5			$7,057,444	3.77%	$8,460,327	-$1,402,883
Total *Lauderdale*	$528,787,572		$12,582,336	$303,842,502	$212,362,734				$21,699,310	4.10%	$25,656,797	-$3,957,487

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED COMBINED CYCLE PRODUCTION PLANT DEPRECIATION RATES

Account	Balance 31-Dec-09	Net Salvage %	Net Salvage Amount	Reserve 31-Dec-09	Unrecovered Balance	Unadjusted Rem. Life	Interim Ret. Rate	Adjusted Rem. Life	Annual Accrual	Accrual Rate	FPL Request	OPC Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Ft. Myers Cycle Plant			(a)x(b)		(a)-(b)-(c)				(e)/(h)	(i)/(a)		(i)-(k)
Ft. Myers Common												
341	$6,239,915	0.00%	$0	$3,876,401	$2,363,514	18.5	0.0005	18.41	$128,382	2.06%	$1,200,043	-$1,071,661
342	$791,798	0.00%	$0	$701,717	$90,081	18.5	0.0045	17.73	$5,081	0.64%	$8,726	-$3,645
343	$65,228,776	0.00%	$3,994,302	$8,568,229	$52,666,245	18.5	0.0015	16.19	$3,253,596	4.99%	$3,909,033	-$655,437
344	$8,965	0.00%	$0	-$983	$9,948	18.5	0.0002	18.47	$539	6.01%	$1,315	-$776
345	$129,090	0.00%	$0	-$93,693	$222,783	18.5	0.0001	18.48	$12,055	9.34%	$134,114	-$122,059
346	$549,339	0.00%	$0	$464,100	$85,239	18.5	0.001	18.33	$4,650	0.85%	$5,777	-$1,127
Total	$72,947,883		$3,994,302	$13,515,771	$55,437,810	18.5			$3,404,303	4.67%	$5,259,008	-$1,854,705
Ft. Myers Unit 2												
341	$24,646,981	0.00%	$0	$9,294,651	$15,352,330	18.5	0.0005	18.41	$833,913	3.38%	$1,162,475	-$328,562
342	$6,389,579	0.00%	$0	$1,882,844	$4,506,735	18.5	0.0045	17.73	$254,187	3.98%	$362,062	-$107,875
343	$372,701,340	0.00%	$6,509,409	$80,959,040	$285,232,891	18.5	0.0015	17.66	$16,154,814	4.33%	$17,699,535	-$1,544,721
344	$40,107,032	0.00%	$0	$11,698,164	$28,408,868	18.5	0.0002	18.47	$1,538,109	3.84%	$2,172,385	-$634,276
345	$51,228,656	0.00%	$0	$18,844,162	$32,384,494	18.5	0.0001	18.48	$1,752,408	3.42%	$2,031,929	-$279,521
346	$3,111,202	0.00%	$0	$875,951	$2,235,251	18.5	0.001	18.33	$121,945	3.92%	$166,767	-$44,822
Total	$498,184,790		$6,509,409	$123,554,812	$368,120,569	18.5			$20,655,375	4.15%	$23,595,153	-$2,939,778
Ft. Myers Unit 3												
341	$2,971,874	0.00%	$0	$451,954	$2,519,920	18.5	0.0005	18.41	$136,878	4.61%	$166,583	-$29,705
342	$3,896,617	0.00%	$0	$753,381	$3,143,236	18.5	0.0045	17.73	$177,283	4.55%	$220,051	-$42,768
343	$74,167,566	0.00%	$3,280,250	$4,907,365	$65,979,951	18.5	0.0015	16.76	$3,936,613	5.31%	$4,571,043	-$634,430
344	$13,759,002	0.00%	$0	$1,935,596	$11,823,406	18.5	0.0002	18.47	$640,141	4.65%	$731,641	-$91,500
345	$9,683,556	0.00%	$0	$1,821,193	$7,862,363	18.5	0.0001	18.48	$425,453	4.39%	$469,436	-$43,983
346	$481,988	0.00%	$0	$72,428	$409,560	18.5	0.001	18.33	$22,344	4.64%	$27,031	-$4,687
Total	$104,960,603		$3,280,250	$9,941,917	$91,738,436	18.5			$5,338,712	5.09%	$6,185,785	-$847,073
Total Ft. Myers	$676,093,276		$3,280,250	$147,012,500	$515,296,814				$29,398,390	4.35%	$35,039,946	-$5,641,556
Manatee Combined Cycle Plant												
Manatee Unit 3												
341	$29,469,798	0.00%	$0	$6,281,544	$23,188,254	20.5	0.0005	20.39	$1,137,237	3.86%	$1,392,070	-$254,833
342	$4,590,462	0.00%	$0	$1,947,711	$2,642,751	20.5	0.0045	19.55	$135,179	2.94%	$167,418	-$32,239
343	$322,367,885	0.00%	$6,206,064	$24,615,580	$291,546,241	20.5	0.0015	19.44	$14,993,692	4.65%	$16,827,424	-$1,833,732
344	$42,301,618	0.00%	$0	$5,849,399	$36,452,219	20.5	0.0002	20.46	$1,781,633	4.21%	$2,033,100	-$251,467
345	$45,805,658	0.00%	$0	$13,587,157	$32,218,501	20.5	0.0001	20.48	$1,573,169	3.43%	$1,734,115	-$160,946
346	$11,065,051	0.00%	$0	$4,334,772	$6,730,279	20.5	0.001	20.29	$331,704	3.00%	$396,832	-$65,128
Total	$455,600,472		$6,206,064	$56,616,163	$392,778,245	20.5			$19,952,614	4.38%	$22,550,959	-$2,598,345
Total Manatee	$455,600,472		$6,206,064	$56,616,163	$392,778,245				$19,952,614	4.38%	$22,550,959	-$2,598,345

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED COMBINED CYCLE PRODUCTION PLANT DEPRECIATION RATES

Account	Balance 31-Dec-09 (a)	Net Salvage % (b)	Net Salvage Amount (c) (a)x(b)	Reserve 31-Dec-09 (d)	Unrecovered Balance (e) (a)-(b)-(c)	Unadjusted Rem. Life (f)	Interim Ret. Rate (g)	Adjusted Rem. Life (h)	Annual Accrual (i) (e)/(h)	Accrual Rate (j) (i)/(a)	FPL Request (k)	OPC Adjustment (l) (i)-(k)
Martin Combined Cycle Plant												
Martin Common												
341	$42,702,563	0.00%	$0	$29,835,777	$12,866,786	10.5	0.0005	10.47	$1,228,919	2.88%	$2,017,356	-$788,437
342	$4,060,727	0.00%	$0	$2,525,715	$1,535,012	10.5	0.0045	10.25	$149,757	3.69%	$208,532	-$58,775
343	$19,947,437	0.00%	$386,985	$17,039,769	$2,520,683	10.5	0.0015	9.91	$254,239	1.27%	$326,989	-$72,750
345	$4,854,959	0.00%	$0	$3,221,098	$1,633,861	10.5	0.0001	10.49	$155,754	3.21%	$188,040	-$32,286
346	$4,094,951	0.00%	$0	$3,513,934	$581,017	10.5	0.001	10.44	$55,653	1.36%	$71,146	-$15,493
Total	$75,660,637		$386,985	$56,136,293	$19,137,359	10.5			$1,844,323	2.44%	$2,812,063	-$967,740
Martin Pipeline												
342	$13,328,900	0.00%	$0	$13,292,886	$36,014	10.5	0.0045	10.25	$3,514	0.03%	$61,055	-$57,541
Total	$13,328,900		$0	$13,292,886	$36,014	10.5			$3,514	0.03%	$61,055	-$57,541
Martin Unit 3												
341	$1,605,301	0.00%	$0	$926,983	$678,318	10.5	0.0005	10.47	$64,787	4.04%	$96,821	-$32,034
342	$170,896	0.00%	$0	$99,346	$71,550	10.5	0.0045	10.25	$6,980	4.08%	$10,150	-$3,170
343	$166,838,305	0.00%	$2,343,760	$90,011,193	$74,483,352	10.5	0.0015	10.05	$7,408,295	4.44%	$7,865,847	-$457,552
344	$20,771,119	0.00%	$0	$9,557,237	$11,213,882	10.5	0.0002	10.49	$1,069,007	5.15%	$1,326,415	-$257,408
345	$25,965,635	0.00%	$0	$18,422,527	$7,543,108	10.5	0.0001	10.49	$719,076	2.77%	$878,551	-$159,475
346	$544,629	0.00%	$0	$310,279	$234,350	10.5	0.001	10.44	$22,447	4.12%	$32,413	-$9,966
Total	$215,895,885		$2,343,760	$119,327,565	$94,224,560	10.5			$9,290,593	4.30%	$10,210,197	-$919,604
Martin Unit 4												
341	$1,275,326	0.00%	$0	$666,386	$608,940	10.5	0.0005	10.47	$58,160	4.56%	$86,609	-$28,449
342	$170,507	0.00%	$0	$89,093	$81,414	10.5	0.0045	10.25	$7,943	4.66%	$11,477	-$3,534
343	$179,942,423	0.00%	$2,738,489	$86,401,865	$90,802,069	10.5	0.0015	10.04	$9,041,841	5.02%	$9,458,517	-$416,676
344	$29,820,193	0.00%	$0	$11,636,365	$18,183,828	10.5	0.0002	10.49	$1,733,444	5.81%	$2,092,123	-$358,679
345	$24,224,816	0.00%	$0	$16,519,213	$7,705,603	10.5	0.0001	10.49	$734,567	3.03%	$885,665	-$151,098
346	$487,415	0.00%	$0	$250,911	$236,504	10.5	0.001	10.44	$22,654	4.65%	$32,787	-$10,133
Total	$235,920,680		$2,738,489	$115,563,833	$117,618,358	10.5			$11,598,609	4.92%	$12,567,178	-$968,569
Martin Unit 8												
341	$23,380,329	0.00%	$0	$4,305,227	$19,075,102	20.5	0.0005	20.39	$935,513	4.00%	$1,159,586	-$224,073
342	$11,051,816	0.00%	$0	$2,372,256	$8,679,560	20.5	0.0045	19.55	$443,967	4.02%	$568,548	-$124,581
343	$328,996,497	0.00%	$6,388,745	$53,780,305	$268,827,447	20.5	0.0015	19.44	$13,829,854	4.20%	$15,442,602	-$1,612,748
344	$40,363,598	0.00%	$0	$6,565,908	$33,797,690	20.5	0.0002	20.46	$1,651,891	4.09%	$1,912,307	-$260,416
345	$52,690,040	0.00%	$0	$18,050,616	$34,639,424	20.5	0.0001	20.48	$1,691,378	3.21%	$1,900,662	-$209,284
346	$4,345,319	0.00%	$0	$3,585,699	$759,620	20.5	0.001	20.29	$37,438	0.86%	$44,110	-$6,672
Total	$460,827,599		$6,388,745	$88,660,011	$365,778,843	20.5			$18,590,041	4.03%	$21,027,815	-$2,437,774
Total Martin	$1,001,633,701		$6,388,745	$392,980,588	$596,795,134				$41,327,079	4.13%	$46,678,308	-$5,351,229

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED COMBINED CYCLE PRODUCTION PLANT DEPRECIATION RATES

Account	Balance 31-Dec-09	Net Salvage %	Net Salvage Amount	Reserve 31-Dec-09	Unrecovered Balance	Unadjusted Rem. Life	Interim Ret. Rate	Adjusted Rem. Life	Annual Accrual	Accrual Rate	FPL Request	OPC Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Putnam Combined Cycle Plant			(a)x(b)		(a)-(b)-(c)				(e)/(h)	(i)/(a)		(i)-(k)
Putnam Common												
341	$12,728,938	0.00%	$0	$9,449,327	$3,279,611	10.5	0.0005	10.47	$313,239	2.46%	$2,414,572	-$2,101,333
342	$11,435,670	0.00%	$0	$8,470,029	$2,965,641	10.5	0.0045	10.25	$289,331	2.53%	$339,209	-$49,878
343	$20,146,555	0.00%	$783,230	$11,834,606	$7,528,719	10.5	0.0015	9.84	$765,056	3.80%	$840,832	-$75,776
344	$170,569	0.00%	$0	$47,851	$122,718	10.5	0.0002	10.49	$11,699	6.86%	$13,712	-$2,013
345	$1,523,346	0.00%	$0	$1,111,862	$411,484	10.5	0.0001	10.49	$39,226	2.58%	$95,007	-$55,781
346	$1,440,520	0.00%	$0	$981,618	$458,902	10.5	0.001	10.44	$43,956	3.05%	$102,062	-$58,106
Total	$47,445,598		$783,230	$31,895,293	$14,767,075	10.5			$1,462,507	3.08%	$3,805,394	-$2,342,887
Putnam Unit 1												
341	$38,546	0.00%	$0	$31,993	$6,553	10.5	0.0005	10.47	$626	1.62%	$6,832	-$6,206
342	$68,736	0.00%	$0	$56,084	$12,652	10.5	0.0045	10.25	$1,234	1.80%	$2,499	-$1,265
343	$61,302,516	0.00%	$2,061,546	$42,334,924	$16,906,046	10.5	0.0015	9.92	$1,703,990	2.78%	$1,859,389	-$155,399
344	$7,708,123	0.00%	$0	$5,576,593	$2,131,530	10.5	0.0002	10.49	$203,196	2.64%	$488,792	-$285,596
345	$7,159,774	0.00%	$0	$5,892,353	$1,267,421	10.5	0.0001	10.49	$120,822	1.69%	$237,861	-$117,039
346	$407,803	0.00%	$0	$332,744	$75,059	10.5	0.001	10.44	$7,190	1.76%	$31,836	-$24,646
Total	$76,685,498		$2,061,546	$54,224,691	$20,399,261	10.5			$2,037,058	2.66%	$2,627,209	-$590,151
Putnam Unit 2												
341	$38,546	0.00%	$0	$27,826	$10,720	10.5	0.0005	10.47	$1,024	2.66%	$10,964	-$9,940
342	$68,672	0.00%	$0	$48,851	$19,821	10.5	0.0045	10.25	$1,934	2.82%	$4,935	-$3,001
343	$59,896,463	0.00%	$1,185,270	$39,499,582	$19,211,611	10.5	0.0015	9.93	$1,934,888	3.23%	$2,078,665	-$143,777
344	$7,979,237	0.00%	$0	$6,074,669	$1,904,568	10.5	0.0002	10.49	$181,560	2.28%	$368,010	-$186,450
345	$7,332,410	0.00%	$0	$5,184,098	$2,148,312	10.5	0.0001	10.49	$204,796	2.79%	$581,068	-$376,272
346	$392,093	0.00%	$0	$278,918	$113,175	10.5	0.001	10.44	$10,841	2.76%	$68,668	-$57,827
Total	$75,707,421		$1,185,270	$51,113,944	$23,408,207	10.5			$2,335,043	3.08%	$3,112,310	-$777,267
Total Putnam	$199,838,517		$1,185,270	$137,233,928	$58,574,543				$5,834,608	2.92%	$9,544,913	-$3,710,305

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED COMBINED CYCLE PRODUCTION PLANT DEPRECIATION RATES

Account	Balance 31-Dec-09 (a)	Net Salvage % (b)	Net Salvage Amount (c) (a)x(b)	Reserve 31-Dec-09 (d)	Unrecovered Balance (e) (a)-(b)-(c)	Unadjusted Rem. Life (f)	Interim Ret. Rate (g)	Adjusted Rem. Life (h)	Annual Accrual (i) (e)/(h)	Accrual Rate (j) (i)/(a)	FPL Request (k)	OPC Adjustment (l) (i)-(k)
Sanford Combined Cycle Plant												
Sanford Common												
341	$60,722,293	0.00%	$0	$25,257,552	$35,464,741	18.5	0.0005	18.41	$1,926,385	3.17%	$3,840,276	-$1,913,891
342	$86,458	0.00%	$0	$59,142	$27,316	18.5	0.0045	17.73	$1,541	1.78%	$2,104	-$563
343	$9,672,403	0.00%	$238,507	$14,848,670	-$5,414,774	18.5	0.0015	17.12	-$316,365	-3.27%	$0	-$316,365
345	$1,165,661	0.00%	$0	$739,852	$425,809	18.5	0.0001	18.48	$23,042	1.98%	$26,706	-$3,664
346	$1,612,112	0.00%	$0	$905,341	$706,771	18.5	0.001	18.33	$38,558	2.39%	$45,407	-$6,849
Total	$73,258,927		$238,507	$41,810,557	$31,209,863	18.5			$1,673,160	2.28%	$3,914,493	-$2,241,333
Sanford Unit 4												
341	$7,273,005	0.00%	$0	$3,129,303	$4,143,702	18.5	0.0005	18.41	$225,079	3.09%	$320,566	-$95,487
342	$1,754,676	0.00%	$0	$564,066	$1,190,610	18.5	0.0045	17.73	$67,152	3.83%	$84,423	-$17,271
343	$274,509,559	0.00%	$8,838,840	$53,940,671	$211,730,048	18.5	0.0015	17.16	$12,335,878	4.49%	$14,065,881	-$1,730,003
344	$28,084,480	0.00%	$0	$5,550,264	$22,534,216	18.5	0.0002	18.47	$1,220,044	4.34%	$2,327,577	-$1,107,533
345	$33,206,417	0.00%	$0	$12,453,807	$20,752,610	18.5	0.0001	18.48	$1,122,977	3.38%	$1,255,924	-$132,947
346	$3,248,040	0.00%	$0	$1,121,261	$2,126,779	18.5	0.001	18.33	$116,027	3.57%	$141,172	-$25,145
Total	$348,076,177		$8,838,840	$76,759,372	$262,477,965	18.5			$15,087,157	4.33%	$18,195,543	-$3,108,386
Sanford Unit 5												
341	$6,858,890	0.00%	$0	$1,694,577	$5,164,313	17.5	0.0005	17.42	$296,459	4.32%	$382,994	-$86,535
342	$1,765,435	0.00%	$0	$429,358	$1,336,077	17.5	0.0045	16.81	$79,481	4.50%	$100,556	-$21,075
343	$254,614,619	0.00%	$4,190,889	$58,741,579	$191,682,151	17.5	0.0015	16.76	$11,436,493	4.49%	$12,422,282	-$985,789
344	$30,030,624	0.00%	$0	$7,303,520	$22,727,104	17.5	0.0002	17.47	$1,300,922	4.33%	$2,342,756	-$1,041,834
345	$33,483,343	0.00%	$0	$9,125,661	$24,357,682	17.5	0.0001	17.48	$1,393,460	4.16%	$1,913,123	-$519,663
346	$2,758,184	0.00%	$0	$670,798	$2,087,386	17.5	0.001	17.35	$120,310	4.36%	$156,776	-$36,466
Total	$329,511,095		$4,190,889	$77,965,493	$247,354,713	17.5			$14,627,125	4.44%	$17,318,487	-$2,691,362
Total Sanford	$750,846,199		$4,190,889	$196,535,422	$541,042,541				$31,387,442	4.18%	$39,428,523	-$8,041,081
Turkey Point Combined Cycle Plant												
Turkey Point Unit 5												
341	$65,601,654	0.00%	$0	$7,133,546	$58,468,108	22.5	0.0005	22.37	$2,613,684	3.98%	$3,132,788	-$519,104
342	$12,540,827	0.00%	$0	$1,363,606	$11,177,221	22.5	0.0045	21.36	$523,278	4.17%	$625,544	-$102,266
343	$373,736,762	0.00%	$21,190,717	$53,233,814	$299,312,231	22.5	0.0015	19.67	$15,217,336	4.07%	$19,241,595	-$4,024,259
344	$3,030,799	0.00%	$0	$321,374	$2,709,425	22.5	0.0002	22.45	$120,687	3.98%	$136,991	-$16,304
345	$38,642,181	0.00%	$0	$5,401,892	$33,240,289	22.5	0.0001	22.47	$1,479,319	3.83%	$1,612,748	-$133,429
346	$10,033,608	0.00%	$0	$1,871,815	$8,161,793	22.5	0.001	22.25	$366,822	3.66%	$430,137	-$63,315
Total	$503,585,831		$21,190,717	$69,326,047	$413,069,067	22.5			$20,321,126	4.04%	$25,179,803	-$4,858,677
Total Turke	$503,585,831		$21,190,717	$69,326,047	$413,069,067				$20,321,126	4.04%	$25,179,803	-$4,858,677
Total CC	$4,116,385,568		$55,024,271	$1,303,547,150	$2,729,919,079				$169,920,569	4.13%	$204,079,249	-$34,158,680

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED GT PRODUCTION PLANT DEPRECIATION RATES

	Balance	Net Salvage		Reserve	Unrecovered	Unadjusted	Interim	Adjusted	Annual	Accrual	FPL	OPC
Account	31-Dec-09	%	Amount	31-Dec-09	Balance	Rem. Life	Ret. Rate	Rem. Life	Accrual	Rate	Request	Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Gas Turbines			(a)x(b)		(a)-(b)-(c)				(e)/(h)	(i)/(a)		(i)-(k)
Lauderdale GTs												
341	$5,855,526	0.0%	$0	$5,275,911	$579,615	10.5	0.0005	10.47	$55,360	0.95%	$134,551	-$79,191
342	$2,028,370	0.0%	$0	$2,169,355	-$140,985	10.5	0.0045	10.25	-$13,755	-0.68%	$0	-$13,755
343	$45,124,101	0.0%	$704,691	$40,099,576	$4,319,834	10.5	0.0015	10.42	$414,571	0.92%	$657,712	-$243,141
344	$17,811,067	0.0%	$0	$16,254,071	$1,556,996	10.5	0.0002	10.49	$148,427	0.83%	$2,744,747	-$2,596,320
345	$4,596,633	0.0%	$0	$4,240,719	$355,914	10.5	0.0001	10.49	$33,929	0.74%	$48,889	-$14,960
346	$234,584	0.0%	$0	$213,624	$20,960	10.5	0.001	10.44	$2,008	0.86%	$6,329	-$4,321
Total	$75,650,281		$704,691	$68,253,256	$6,692,334	10.5			$640,540	0.85%	$3,592,228	-$2,951,688
Ft. Myers GTs												
341	$4,027,168	0.0%	$0	$3,477,292	$549,876	10.5	0.0005	10.47	$52,519	1.30%	$385,582	-$333,063
342	$3,232,602	0.0%	$0	$3,185,872	$46,730	10.5	0.0045	10.25	$4,559	0.14%	$13,970	-$9,411
343	$46,543,314	0.0%	$844,786	$34,733,846	$10,964,682	10.5	0.0015	10.42	$1,052,273	2.26%	$1,266,616	-$214,343
344	$21,981,629	0.0%	$0	$15,865,315	$6,116,314	10.5	0.0002	10.49	$583,061	2.65%	$2,394,321	-$1,811,260
345	$14,207,743	0.0%	$0	$5,166,929	$9,040,814	10.5	0.0001	10.49	$861,851	6.07%	$1,244,851	-$383,000
346	$91,395	0.0%	$0	$78,920	$12,475	10.5	0.001	10.44	$1,195	1.31%	$4,967	-$3,772
Total	$90,083,851		$844,786	$62,508,174	$26,730,891	10.5			$2,555,458	2.84%	$5,310,307	-$2,754,849
Pt. Everglades GTs												
341	$3,986,996	0.0%	$0	$3,293,313	$693,683	10.5	0.0005	10.47	$66,254	1.66%	$119,911	-$53,657
342	$9,942,862	0.0%	$0	$10,230,715	-$287,853	10.5	0.0045	10.25	-$28,083	-0.28%	$1,011	-$29,094
343	$21,133,092	0.0%	$583,677	$16,467,969	$4,081,446	10.5	0.0015	10.42	$391,693	1.85%	$452,491	-$60,798
344	$11,374,968	0.0%	$0	$10,068,397	$1,306,571	10.5	0.0002	10.49	$124,554	1.09%	$592,241	-$467,687
345	$3,411,445	0.0%	$0	$2,878,758	$532,687	10.5	0.0001	10.49	$50,780	1.49%	$62,510	-$11,730
346	$95,330	0.0%	$0	$78,262	$17,068	10.5	0.001	10.44	$1,635	1.71%	$2,524	-$889
Total	$49,944,693		$583,677	$43,017,414	$6,343,602	10.5			$606,834	1.22%	$1,230,688	-$623,854
Total GT	$215,678,825		$583,677	$173,778,844	$39,766,827				$3,802,831	1.76%	$10,133,223	-$6,330,392

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED GT PRODUCTION PLANT DEPRECIATION RATES

Account	Balance 31-Dec-09	Net Salvage %	Net Salvage Amount	Reserve 31-Dec-09	Unrecovered Balance	Unadjusted Rem. Life	Interim Ret. Rate	Adjusted Rem. Life	Annual Accrual	Accrual Rate	FPL Request	OPC Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
West County 1			(a)x(b)		(a)-(b)-(c)				(e)/(h)	(i)/(a)		(i)-(k)
341	$87,967,441	0.00%	$0	$0	$87,967,441	24.5	0.0005	24.35	$3,612,626	4.11%	$4,157,693	-$545,067
342	$16,816,412	0.00%	$0	$0	$16,816,412	24.5	0.0045	23.15	$726,411	4.32%	$827,939	-$101,528
343	$501,156,064	0.00%	$30,406,352	$0	$470,749,712	24.5	0.0015	21.13	$22,278,590	4.45%	$27,990,084	-$5,711,494
344	$4,064,100	0.00%	$0	$0	$4,064,100	24.5	0.0002	24.44	$166,289	4.09%	$182,702	-$16,413
345	$51,816,586	0.00%	$0	$0	$51,816,586	24.5	0.0001	24.47	$2,117,556	4.09%	$2,246,923	-$129,367
346	$13,454,397	0.00%	$0	$0	$13,454,397	24.5	0.001	24.2	$555,967	4.13%	$626,975	-$71,008
Total	$675,275,000		$30,406,352	$0	$644,868,648	24.5			$29,457,438	4.36%	$36,032,316	-$6,574,878
West County 2												
341	$74,765,193	0.00%	$0	$0	$74,765,193	24.5	0.0005	24.35	$3,070,439	4.11%	$3,533,702	-$463,263
342	$14,292,587	0.00%	$0	$0	$14,292,587	24.5	0.0045	23.15	$617,390	4.32%	$703,681	-$86,291
343	$425,942,021	0.00%	$25,842,924	$0	$400,099,097	24.5	0.0015	21.09	$18,975,474	4.45%	$23,789,301	-$4,813,827
344	$3,454,155	0.00%	$0	$0	$3,454,155	24.5	0.0002	24.44	$141,332	4.09%	$155,282	-$13,950
345	$44,039,897	0.00%	$0	$0	$44,039,897	24.5	0.0001	24.47	$1,799,751	4.09%	$1,909,702	-$109,951
346	$11,435,147	0.00%	$0	$0	$11,435,147	24.5	0.001	24.2	$472,527	4.13%	$532,878	-$60,351
Total	$573,929,000		$25,842,924	$0	$548,086,076	24.5			$25,076,913	4.37%	$30,624,546	-$5,547,633
					$441,614,377							
West County 3												
341	$104,725,308	0.00%	$0	$0	$104,725,308	24.5	0.0005	24.35	$4,300,834	4.11%	$4,949,737	-$648,903
342	$20,019,951	0.00%	$0	$0	$20,019,951	24.5	0.0045	23.15	$864,793	4.32%	$985,662	-$120,869
343	$596,626,689	0.00%	$36,198,780	$0	$560,427,909	24.5	0.0015	21.13	$26,522,678	4.45%	$33,322,217	-$6,799,539
344	$4,838,314	0.00%	$0	$0	$4,838,314	24.5	0.0002	24.44	$197,967	4.09%	$217,506	-$19,539
345	$61,687,687	0.00%	$0	$0	$61,687,687	24.5	0.0001	24.47	$2,520,952	4.09%	$2,674,963	-$154,011
346	$16,017,471	0.00%	$0	$0	$16,017,471	24.5	0.001	24.2	$661,879	4.13%	$746,414	-$84,535
Total	$803,915,420		$36,198,780	$0	$767,716,640	24.5			$35,069,103	4.36%	$42,896,499	-$7,827,396
West CC	$2,053,119,420		$92,448,056	$0	$1,960,671,364				$89,603,454	4.36%	$109,553,361	-$19,949,907

SOURCES AND REFERENCES

Columns (a, d, & k)	: FPL Exhibit CRC-1.
Column (h)	: Column (f) time (1- (Column (g) times Column (f))/2)).
Column (i)	: Column (e) divided by Column (h).
Column (j)	: Column (i) divided by Column (a).
Column (l)	: Column (i) less Column (k).

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED TRANSMISSION AND DISTRIBUTION PLANT DEPRECIATION RATES

Account	Balance 31-Dec-09	Net Salvage %	Net Salvage Amount	Reserve 31-Dec-09	Unrecovered Balance	Remaining Life	Annual Expense	Annual Rate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
TRANSMISSION PLANT								
350.2 Easements	$175,571,160	0%	$0	$50,530,943	$125,040,217	77.51	$1,613,214	0.92%
352.0 Structures & Improvements	$85,889,291	-15%	-$12,883,394	$23,196,106	$75,576,579	47.81	$1,580,769	1.84%
353.0 Station Equipment	$1,011,113,785	0%	$0	$244,270,562	$766,843,223	33.48	$22,904,517	2.27%
353.1 Station Eqpmnt - Generator Step-Up Tran	$197,711,163	0%	$0	$42,535,608	$155,175,555	34.72	$4,469,342	2.26%
354.0 Towers & Fixtures	$168,243,833	0%	$0	$74,614,045	$93,629,788	42.04	$2,227,160	1.32%
355.0 Poles & Fixtures	$740,416,858	-30%	-$222,125,057	$298,146,133	$664,395,782	33.43	$19,874,238	2.68%
356.0 Overhead Conductors & Devices	$548,383,891	-40%	-$219,353,556	$214,668,340	$553,069,107	40.34	$13,710,191	2.50%
357.0 Underground Conduit	$54,394,725	0%	$0	$24,725,846	$29,668,879	40.89	$725,578	1.33%
358.0 Underground Conductors & Devices	$58,584,827	-10%	-$5,858,483	$32,491,841	$31,951,469	41.45	$770,844	1.32%
359.0 Roads & Trails	$82,226,489	-10%	-$8,222,649	$27,502,488	$62,946,650	47.03	$1,338,436	1.63%
Total Transmission	$3,122,536,022		-$468,443,139	$1,032,681,912	$2,558,297,249		$69,214,289	0.022166
DISTRIBUTION PLANT - DEPRECIABLE								
361.0 Structures & Improvements	$181,432,252	-15%	-$27,214,838	$44,324,043	$164,323,047	50.39	$3,261,025	1.80%
362.0 Station Equipment	$1,399,018,981	-10%	-$139,901,898	$429,047,355	$1,109,873,524	38.48	$28,842,867	2.06%
364.0 Poles, Towers & Fixtures	$878,114,186	-60%	-$526,868,512	$406,815,277	$998,167,421	30.56	$32,662,546	3.72%
365.0 Overhead Conductors & Devices	$1,155,296,902	-50%	-$577,648,451	$624,469,987	$1,108,475,366	32.15	$34,478,238	2.98%
366.6 Underground Conduit,Duct System	$1,293,088,609	0%	$0	$317,774,205	$975,314,404	59.03	$16,522,351	1.28%
366.7 Underground Conduit,Direct Buried	$76,179,331	0%	$0	$19,429,379	$56,749,952	39.97	$1,419,814	1.86%
367.6 UG Conductors & Devices Duct System	$1,344,075,779	0%	$0	$324,691,177	$1,019,384,602	31.95	$31,905,621	2.37%
367.7 UG Conductors & Devices,Direct Buried	$427,212,466	0%	$0	$247,924,379	$179,288,087	27.92	$6,421,493	1.50%
368.0 Line Transformers	$1,810,216,247	-20%	-$362,043,249	$772,661,777	$1,399,597,719	24.34	$57,501,961	3.18%
369.1 Services, Overhead	$180,627,855	-85%	-$153,533,677	$95,646,630	$238,514,902	36.71	$6,497,273	3.60%
369.7 Services, Underground	$609,994,306	-5%	-$30,499,715	$247,438,438	$393,055,583	29.98	$13,110,593	2.15%
370.0 Meters	$225,844,517	-10%	-$22,584,452	$81,144,078	$167,284,891	27.14	$6,163,776	2.73%
370.1 AMR Meters	$30,378,322	-10%	-$3,037,832	$733,042	$32,683,112	19.18	$1,704,020	5.61%
371.0 Installations on Customer's Premises	$63,873,263	-25%	-$15,968,316	$57,068,106	$22,773,473	22.6	$1,007,676	1.58%
373.0 Street Lighting & Signal Systems	$375,203,879	-20%	-$75,040,776	$230,756,332	$219,488,323	28.35	$7,742,093	2.06%
Total Distribution	$10,050,556,895		-$1,934,341,715	$3,899,924,205	$8,084,974,405		$249,241,349	2.48%

OFFICE OF PUBLIC COUNSEL'S RECOMMENDED GENERAL PLANT DEPRECIATION RATES

Account	Balance 31-Dec-09	Net Salvage %	Net Salvage Amount	Reserve 31-Dec-09	Unrecovered Balance	Remaining Life	Annual Expense	Annual Rate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
GENERAL PLANT - DEPRECIABLE								
390.0 Structures & Improvements	$405,787,732	25%	$101,446,933	$158,612,363	$145,728,436	42.72	$3,411,246	0.84%
392.01 Aircraft - Fixed Wing (Jet)	$44,041,046	50%	$22,020,523	$22,866,644	-$846,121	2.27	-$372,741	-0.85%
392.02 Aircraft - Rotary Wing	$8,926,387	50%	$4,463,194	$3,460,055	$1,003,139	4.5	$222,920	2.50%
392.1 Transportation - Automobiles	$2,066,181	15%	$309,927	$867,802	$888,452	3.42	$259,781	12.57%
392.2 Transportation - Light Trucks	$26,453,827	15%	$3,968,074	$12,689,927	$9,795,826	5.1	$1,920,750	7.26%
392.3 Transportation - Heavy Trucks	$156,049,583	15%	$23,407,437	$97,983,924	$34,658,222	5.75	$6,027,517	3.86%
392.4 Transportation - Tractor-Trailers	$571,817	0%	$0	$371,149	$200,668	2.41	$83,265	14.56%
392.9 Transportation - Trailers	$15,012,848	15%	$2,251,927	$6,467,243	$6,293,678	12.77	$492,849	3.28%
396.1 Power Operated Equipment (Transportati	$5,329,433	20%	$1,065,887	$2,950,374	$1,313,172	6.66	$197,173	3.70%
396.8 Other Power Operated Equipment	$31,694	20%	$6,339	$26,820	-$1,465	6.77	-$216	-0.68%
397.8 Communications Equipment - Fiber Optic	$7,822,814	0%	$0	$4,639,350	$3,183,464	7.93	$401,446	5.13%
Total General	$672,093,362		$158,940,241	$310,935,651	$202,217,470		$12,643,989	
Total Mass Property	$13,845,186,279		-$2,243,844,614	$5,243,541,768	$10,845,489,125		$331,099,626	

SOURCES AND REFERENCES

Columns (a & d) : FPL Exhibit CRC-1.
Column (c) : Column (a) times Column (b).
Column (e) : Column (a) less Column (c) less Column (d).
Column (g) : Column (e) divided by Column (f).
Column (h) : Column (g) divided by Column (a).

OFFICE OF PUBLIC COUNSEL'S SUMMARY OF EXCESS RESERVES
BASED ON PLANT AS ESTIMATED ENDING DECEMBER 31, 2009

	Company			OPC		OPC Incremental
	Book Reserve	Theoretical Reserve	Excess Reserve	Theoretical Reserve	Excess Reserve	Excess Reserve
	(a)	(b)	(c)	(d)	(e)	(f)
Steam	$ 2,072,703,705	$ 1,662,593,531	$ 410,110,174	$ 1,256,129,721	$ 816,573,984	$ 406,463,810
Nuclear	$ 2,121,178,163	$ 1,743,670,904	$ 377,507,259	$ 1,736,593,296	$ 384,584,867	$ 7,077,608
Combined Cycle	$ 1,303,547,150	$ 1,277,602,440	$ 25,944,710	$ 1,236,286,671	$ 67,260,479	$ 41,315,769
Gas Turbines	$ 173,778,844	$ 145,751,058	$ 28,027,786	$ 127,341,760	$ 46,437,084	$ 18,409,298
Total Production	$ 5,671,207,862	$ 4,829,617,933	$ 841,589,929	$ 4,356,351,448	$ 1,314,856,414	$ 473,266,485
Transmission	$ 1,032,681,912	$ 1,048,319,348	$ (15,637,436)	$ 822,264,418	$ 210,417,494	$ 226,054,930
Distribution	$ 3,899,924,205	$ 3,559,394,856	$ 340,529,349	$ 2,817,487,801	$ 1,082,436,404	$ 741,907,055
General	$ 310,935,651	$ 232,057,078	$ 78,878,573	$ 178,449,724	$ 132,485,927	$ 53,607,354
Total Mass Property	$ 5,243,541,768	$ 4,839,771,282	$ 403,770,486	$ 3,818,201,943	$ 1,425,339,825	$ 1,021,569,339
Grand Total	$ 10,914,749,630	$ 9,669,389,215	$ 1,245,360,415	$ 8,174,553,391	$ 2,740,196,239	$ 1,494,835,824

SOURCES AND REFERENCES

Columns (a-c)	:Company values from Exhibit CRC-1 page 53.
Column (d)	: OPC theoretical reserve based on individual recalculation by plant account and by unit by account for production plant.
Column (e)	: Column (a) less Column (d).
Column (f)	: Column (e) less Column (c).

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 183
COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Jacob Pous (JP-2)
DATE 08/31/09

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI **EXHIBIT** 184
COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Jacob Pous (JP-3)
DATE 08/31/09

EXAMPLE OF FPL'S CALCULATION ERROR OF REMAINING LIFE
CALCULATION BASED ON ACCOUNT 397.8 COMMUNICATIONS EQUIPMENT

Year	Surviving Balance	Rem. Life	Calculated Reserve	Correct Allocated Reserve	Company Calculation of Reserve Complete	Company Calculation of Reserve Remaining	Company Calculation of Reserve Total	Correct Future Accruals	Dollar Weighted Rem. Life
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1994	$741.09	4.31	$422	$1,206	$741		$741	-$465	-$2,004
1995	$15,757.06	4.54	$8,603	$24,607	$15,757		$15,757	-$8,850	-$40,181
1996	$52,917.25	4.79	$27,570	$78,856	$52,917		$52,917	-$25,939	-$124,246
1997	$101,742.90	5.05	$50,363	$144,048	$101,743		$101,743	-$42,306	-$213,643
1998	$123,577.83	5.32	$57,834	$165,419	$123,578		$123,578	-$41,841	-$222,596
1999	$366,049.07	5.60	$161,062	$460,672	$366,049		$366,049	-$94,622	-$529,886
2000	$927,873.80	5.89	$381,356	$1,090,762	$927,874		$927,874	-$162,889	-$959,414
2001	$368,682.21	6.20	$140,099	$400,715	$368,682		$368,682	-$32,032	-$198,601
2002	$436,752.96	6.53	$151,553	$433,476	$436,753		$436,753	$3,277	$21,401
2003	$400,773.42	6.87	$125,442	$358,792	$400,773		$400,773	$41,981	$288,413
2004	$487,596.78	7.23	$135,064	$386,314		$481,193	$481,193	$101,283	$732,277
2005	$108,488.20	7.62	$25,820	$73,851		$91,989	$91,989	$34,637	$263,932
2006	$297,843.98	8.02	$58,973	$168,676		$210,103	$210,103	$129,168	$1,035,927
2007	$87,812.39	8.47	$13,435	$38,428		$47,866	$47,866	$49,384	$418,287
2008	$2,042,360.23	8.99	$206,278	$590,002		$734,907	$734,907	$1,452,359	$13,056,705
2009	$2,003,845.30	9.61	$78,150	$223,526		$278,424	$278,424	$1,780,319	$17,108,868
Total	$7,822,814.47		$1,622,026	$4,639,350	$2,794,868	$1,844,482	$4,639,350	$3,183,464	$30,635,237

Total that has not exceed investment	$1,480,797	
Correct Dollar Weighted Remaining Life - Years		9.62
Company's Incorrectly Calculated Remaining Life - Years		9.3
Company Error - Years		-0.32

SOURCES AND REFERENCES

Column (a)	: Exhibit CRC-1, page 720 Column (2).
Column (b) 2009-2004	: Exhibit CRC-1, page 720 Column (6).
Column (b) 2003-1994	: Calculated from standard Iowa Survivor Curve Tables.
Column (c)	: Exhibit CRC-1, page 720 Column (3).
Column (d)	: Allocation of Column (d) total to individual years based on total of Column (c).
Column (e) 2003-1994	: Limitation of allocation of Column (d) to dollar level of investment in Column (a).
Column (f) 2009-2004	: Allocation of remaining $ in Column (d) after limitation in Column (e) to remaining individual years based on total in Column (d) that has not exceed investment ($1,480,797).
Column (g)	: Addition of Columns (e & f) which matches Exhibit CRC-1, page 720 Column (4).
Column (h)	: Column (a) less Column (d) (i.e., surviving original cost less corrected allocation of reserve, net plant.
Column (i)	: Column (b) times Column (h) (i.e., remaining life times corrected future annual accruals).
Corrected Rem. Life	: Total of Column (i) divided by column (h).

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080677-EI & 090130-EI EXHIBIT 185

COMPANY Office of Public Counsel (OPC) (Direct)

WITNESS Jacob Pous (JP-4)

DATE 08/31/09

**OFFICE OF PUBLIC COUNSEL'S
RECOMMENDED LEVEL FOR
INTERIM RETIREMENT RATES**

Account No.	Data Points	% Surviving	Interim Retirement Rate
311	50	0.7929	0.0041
312	50	0.6231	0.0075
314	50	0.614	0.0077
315	50	0.6123	0.0078
316	50	0.5855	0.0083
321	30	0.9489	0.0017
322	30	0.8679	0.0044
323	30	0.7355	0.0088
324	30	0.9669	0.0011
325	30	0.9198	0.0027

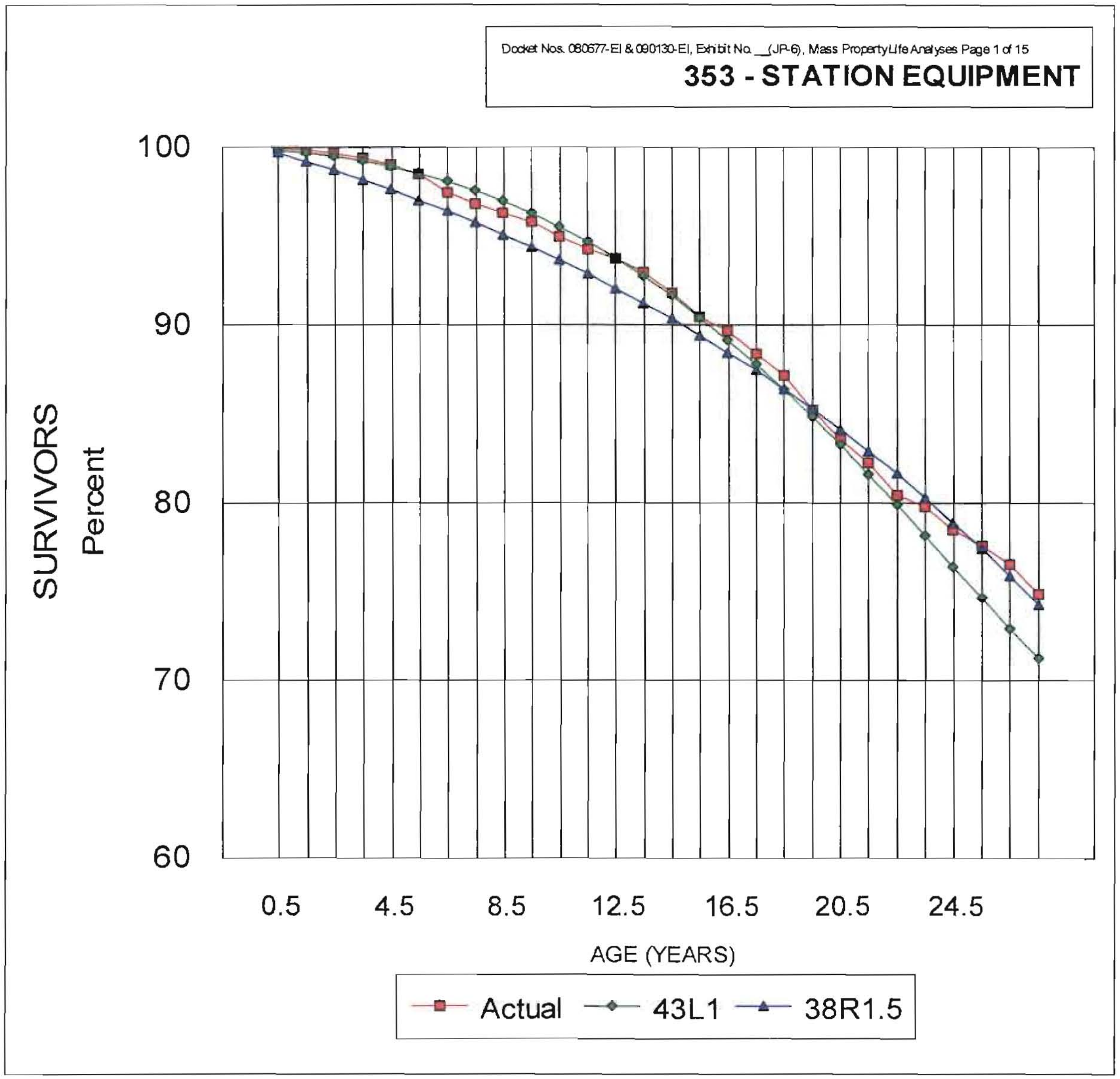
Account No.	1993-2007	Regular Retirements	Interim Retirement Rate	93-07 Ending Balance
341	15	$2,181,304	0.0005	$320,520,601
342	15	$5,177,925	0.0045	$75,991,801
343	15	$57,196,593	0.0015	$2,620,906,141
344	15	$1,031,442	0.0002	$301,977,610
345	15	$505,856	0.0001	$373,209,426
346	15	$700,003	0.0010	$46,339,824

SOURCES AND REFERENCES

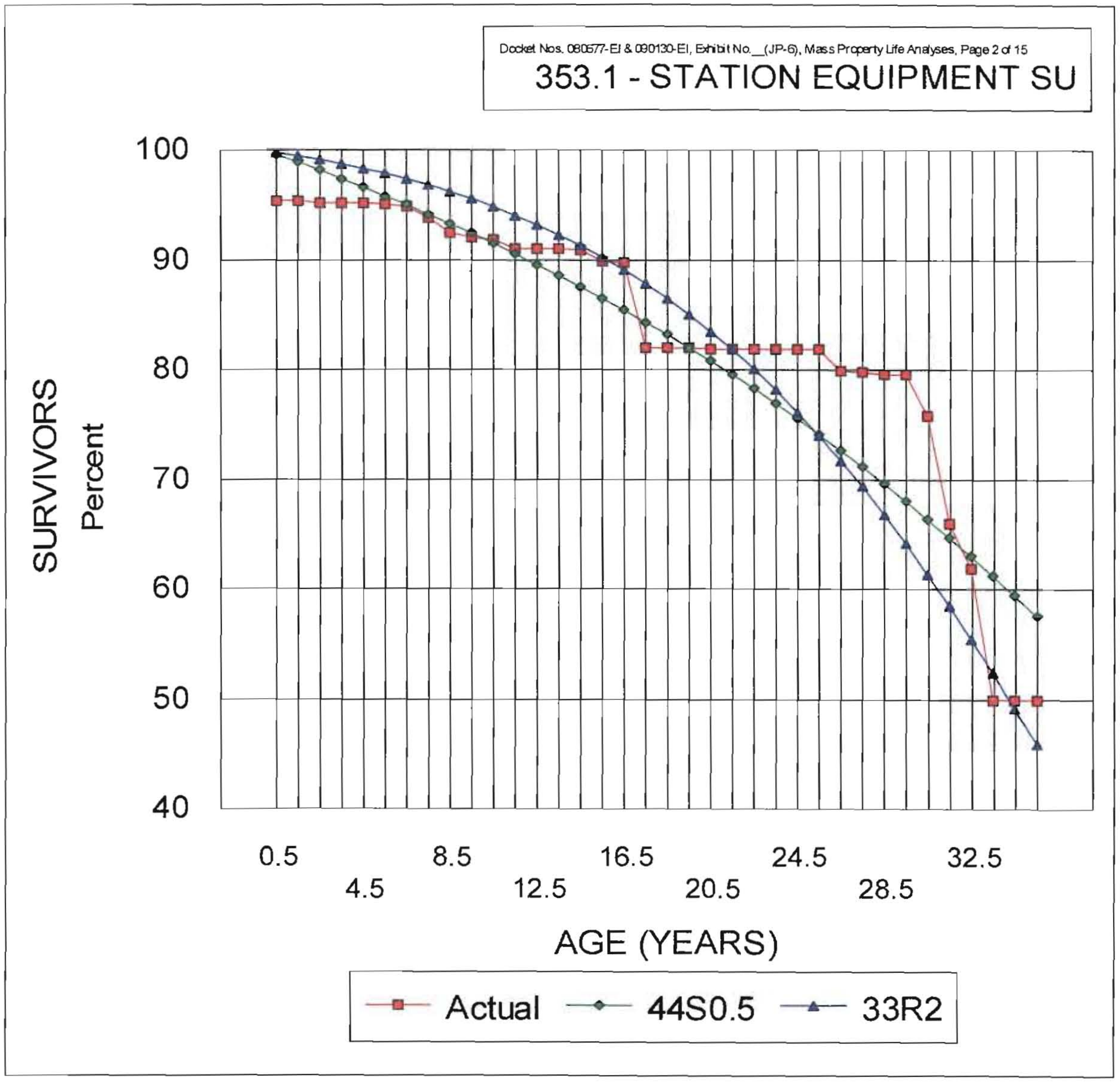
Steam Accounts: Exhibit CRC-1 pages 406, 409, 412, 415, and 418. Excludes impact from oldest plants due to older technology, construction, etc.
Nuclear Accounts: Exhibit CRC-1 for past 30 years.
Other Production Accounts: Exhibit CRC-1 for combined cycle investment beginning in 1993. Excludes retirements at age of 0 and 1 years for Account 343.

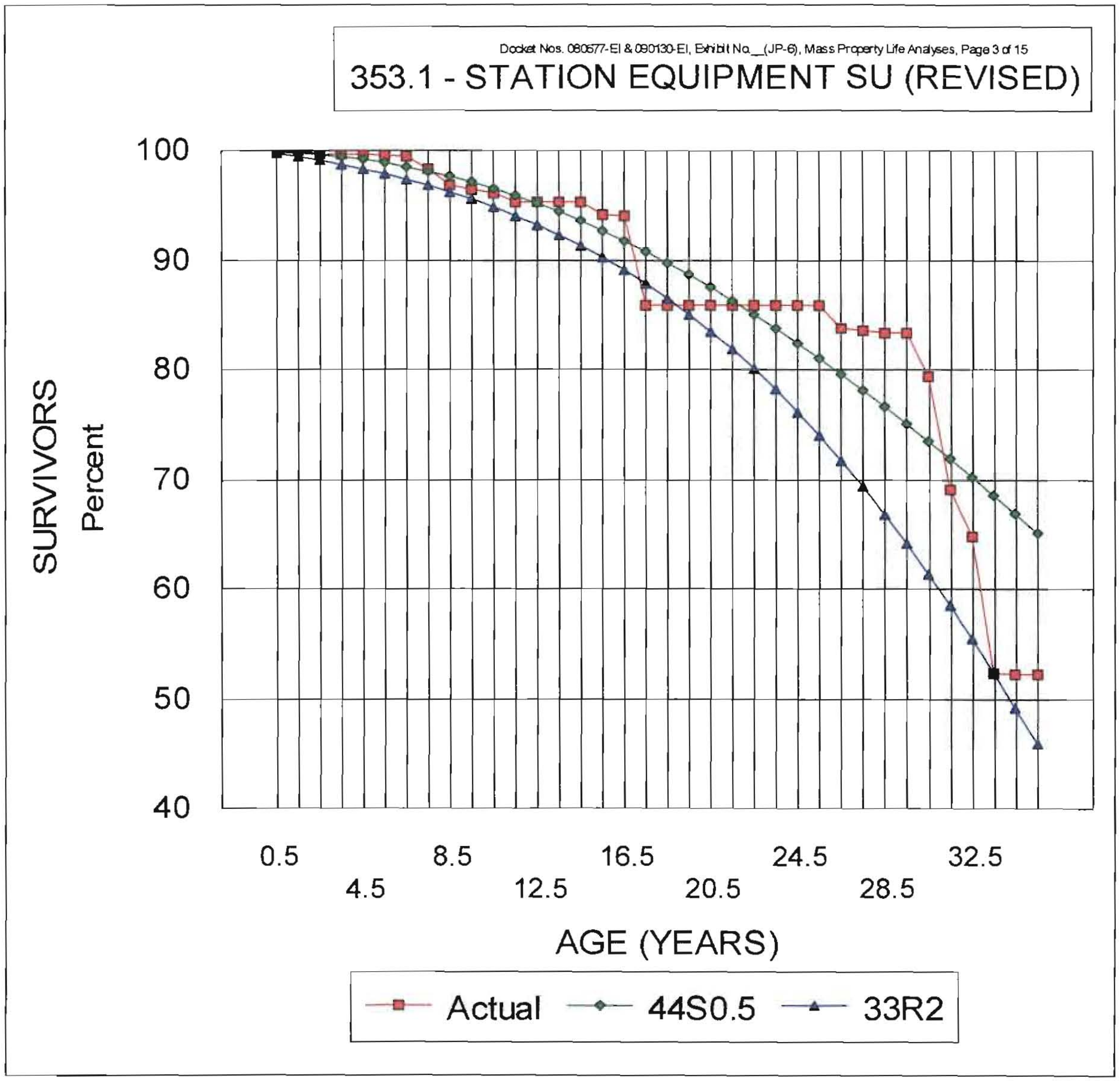
Account Description	FPL CURVE	FPL LIFE	OPC CURVE	OPC LIFE
350.2 Transmission Easements	S4	50	S4	95
353 Transmission Substation Equipment	R1.5	38	L1	43
353.1 Transmission Substation Equipment Step-Up Transformers	R2	33	S0.5	44
354 Transmission Towers & Fixtures	R5	40	R4	60
356 Transmission Overhead Conductor	R1.5	47	S0	51
359 Transmission Roads and Trails	SQ	50	SQ	65
362 Distribution Substation Equipment	R1.5	41	S0	48
364 Distribution Poles, Towers & Fixtures	R2	37	R1.5	41
365 Distribution OH Conductors & Devices	S0	40	S0	43
367.6 Distribution Underground Conductor - Duct System	S0	38	L1	40
367.7 Distribution Underground Conductors – Direct Buried	R2	35	S0.5	43
368 Distribution Line Transformers	L1.5	32	L1.5	34
369.7 Distribution Services Underground	R2	34	S0.5	41
370 Distribution Meters	R2.5	36	S1.5	38
373 Distribution Street Lighting & Signals	R0.5	30	L0	35
390 General Structures & Improvements	R1.5	50	S0	56
392.01 General Aircraft – Fixed Wing	SQ	7	R5	9
392.02 General Aircraft – Rotary Wing	SQ	7	R5	9

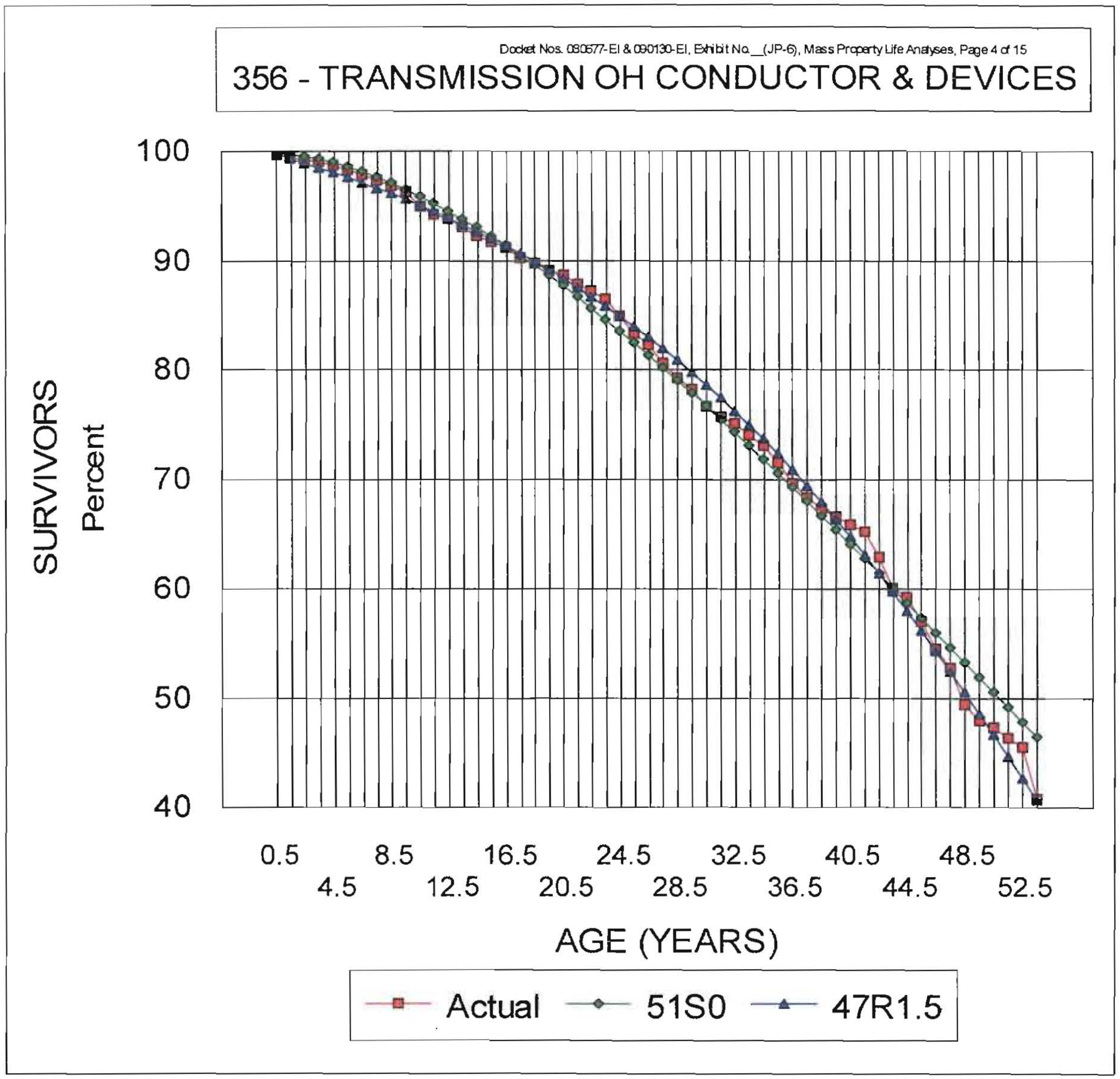
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 186
COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Jacob Pous (JP-5)
DATE 08/31/09

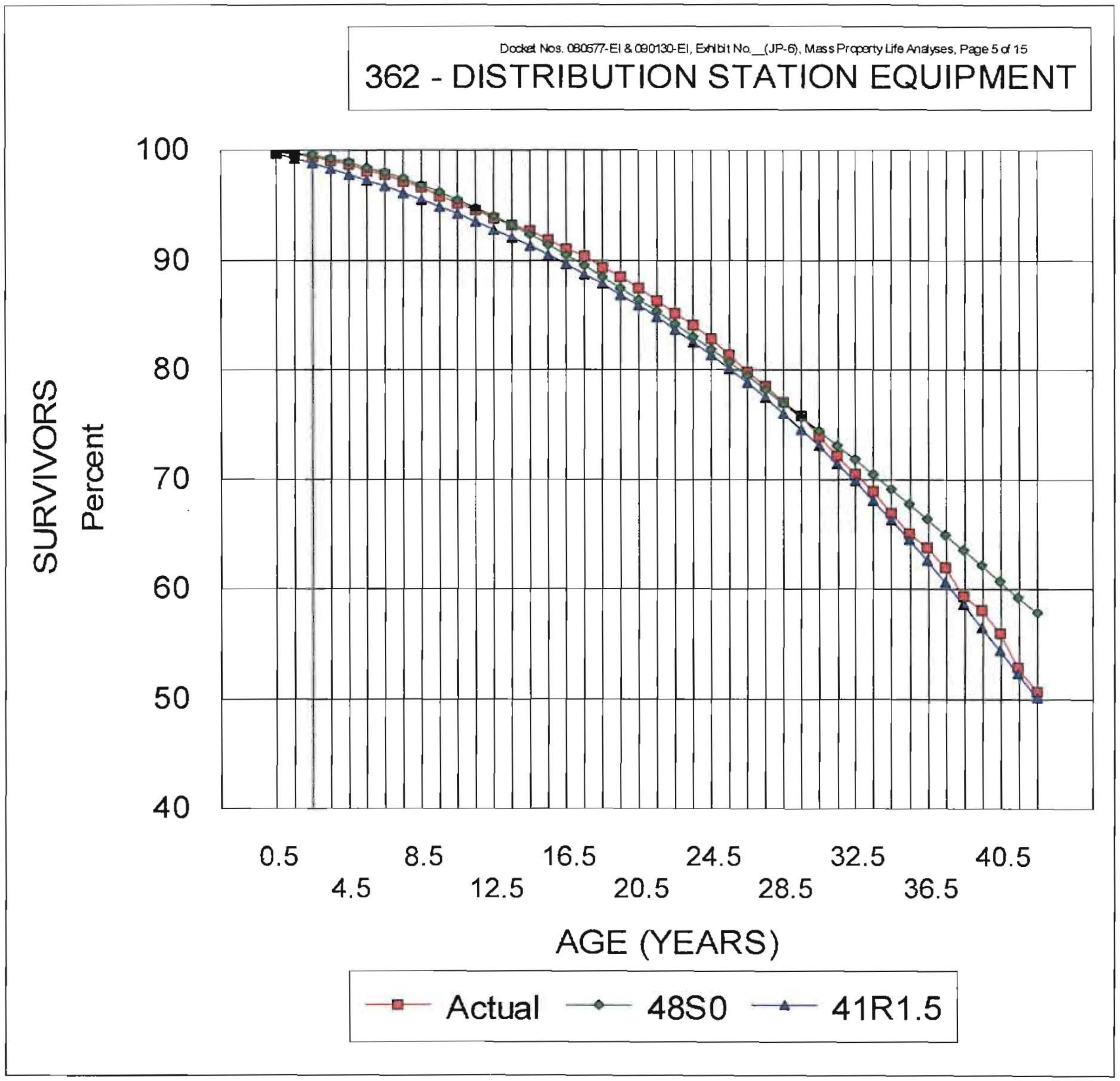


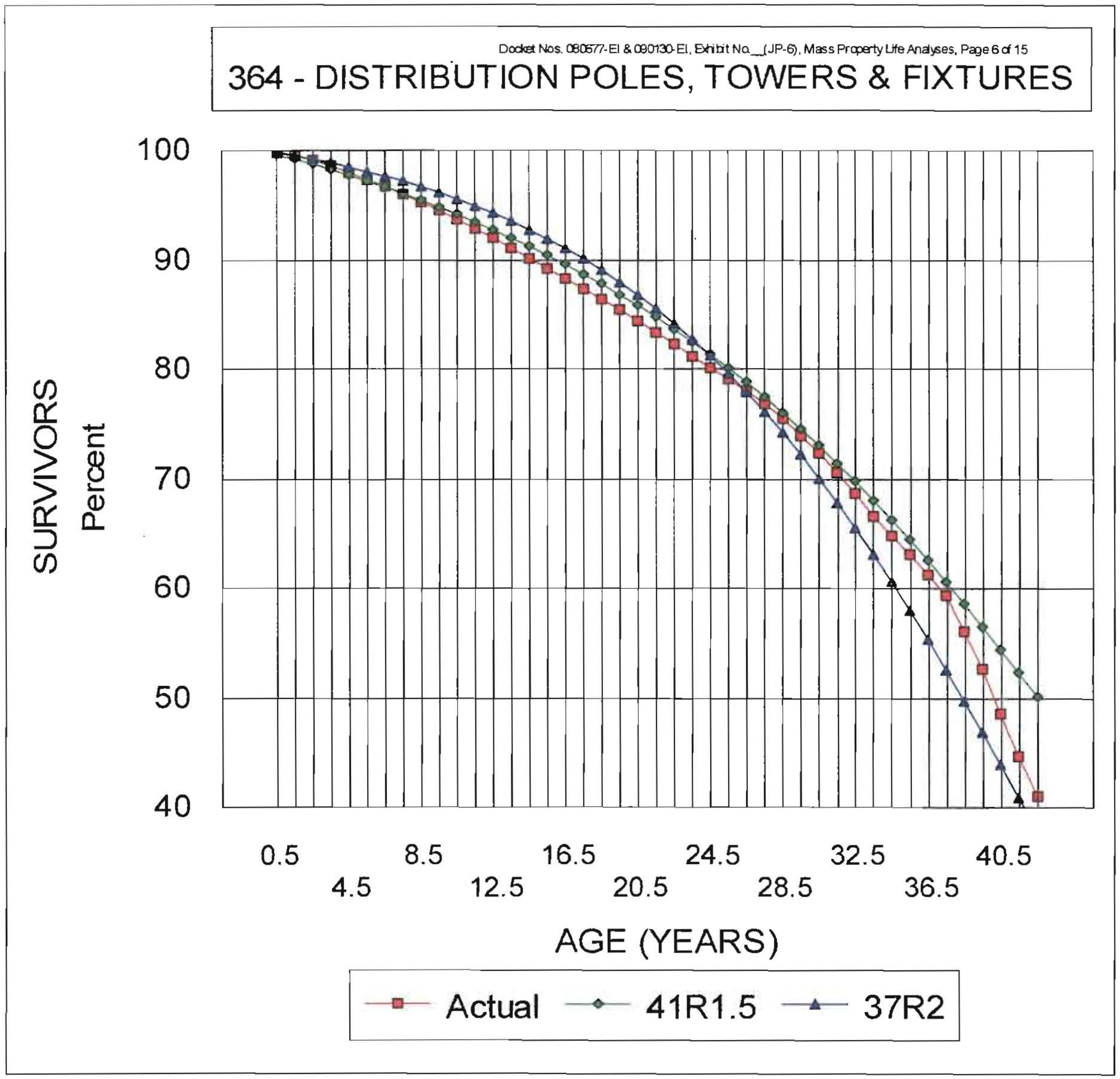
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 187
COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Jacob Pous (JP-6)
DATE 08/31/09

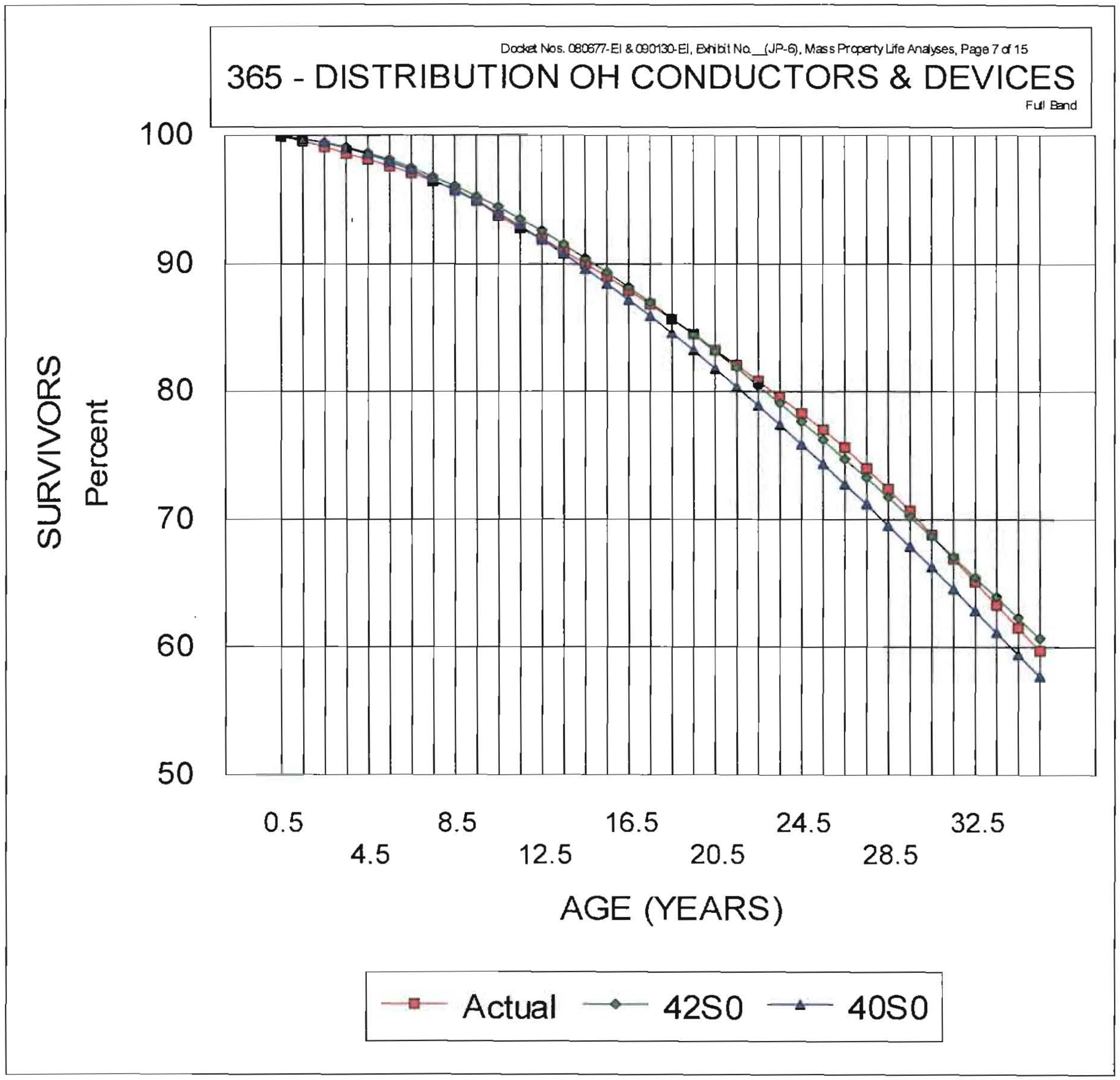

Docket Nos. 080677-EI & 090130-EI, Exhibit No.__(JP-6), Mass Property Life Analyses, Page 2 of 15
353.1 - STATION EQUIPMENT SU
SURVIVORS
Percent
100
90
80
70
60
50
40
0.5
4.5
8.5
12.5
16.5
20.5
24.5
28.5
32.5
AGE (YEARS)
Actual
44S0.5
33R2

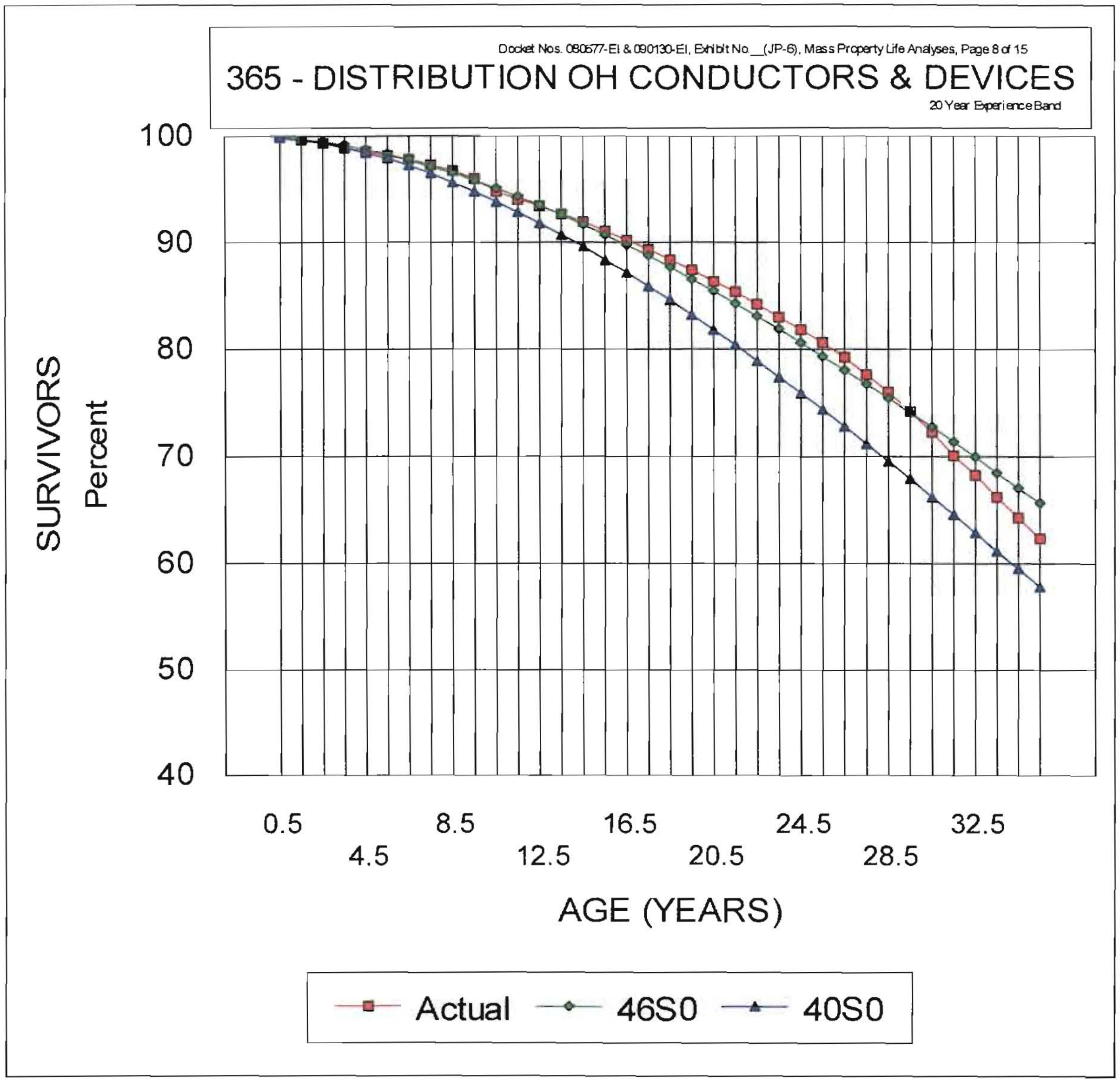

Docket Nos. 080677-EI & 090130-EI, Exhibit No.__(JP-6), Mass Property Life Analyses, Page 3 of 15
353.1 - STATION EQUIPMENT SU (REVISED)
SURVIVORS
Percent
100
90
80
70
60
50
40
0.5
4.5
8.5
12.5
16.5
20.5
24.5
28.5
32.5
AGE (YEARS)
Actual
44S0.5
33R2

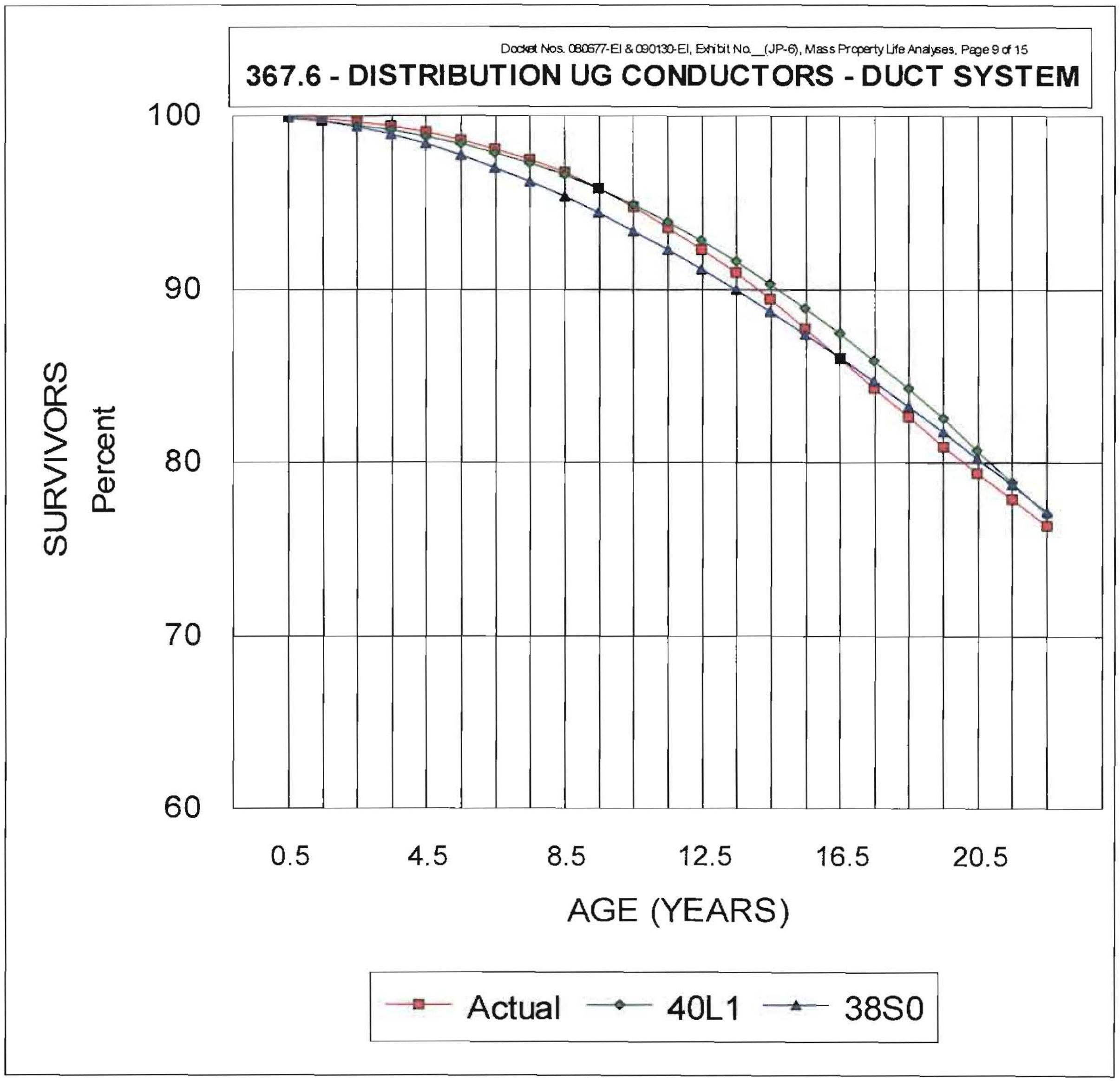

Docket Nos. 080677-EI & 090130-EI, Exhibit No.__(JP-6), Mass Property Life Analyses, Page 4 of 15
356 - TRANSMISSION OH CONDUCTOR & DEVICES
SURVIVORS
Percent
100
90
80
70
60
50
40
0.5
4.5
8.5
12.5
16.5
20.5
24.5
28.5
32.5
36.5
40.5
44.5
48.5
52.5
AGE (YEARS)
Actual
51S0
47R1.5

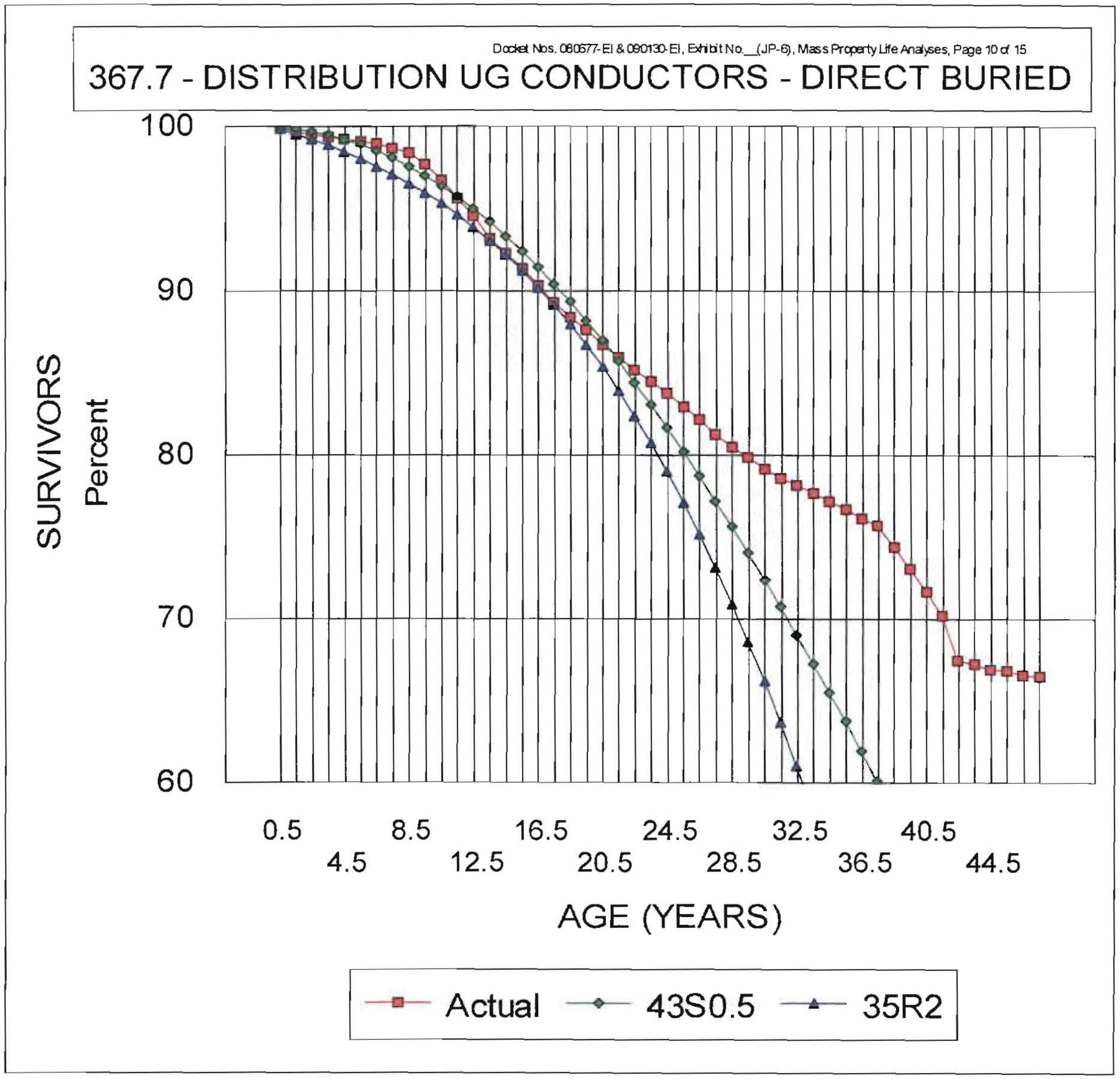

Docket Nos. 080677-EI & 090130-EI, Exhibit No.__(JP-6), Mass Property Life Analyses, Page 5 of 15
362 - DISTRIBUTION STATION EQUIPMENT
100
90
80
70
60
50
40
SURVIVORS
Percent
0.5
4.5
8.5
12.5
16.5
20.5
24.5
28.5
32.5
36.5
40.5
AGE (YEARS)
Actual
48S0
41R1.5

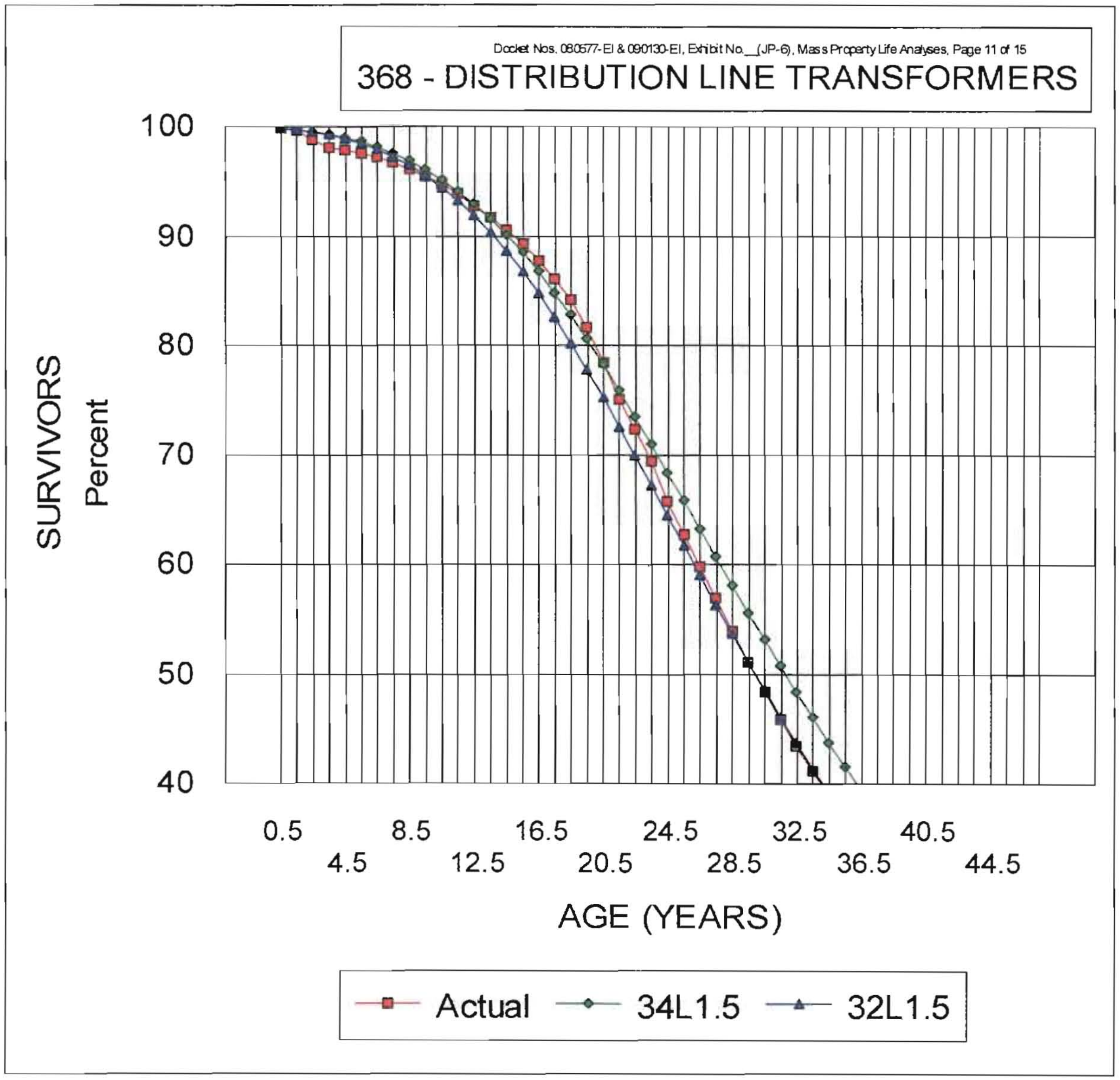

Docket Nos. 080677-EI & 090130-EI, Exhibit No.__(JP-6), Mass Property Life Analyses, Page 6 of 15
364 - DISTRIBUTION POLES, TOWERS & FIXTURES
SURVIVORS
Percent
100
90
80
70
60
50
40
0.5
4.5
8.5
12.5
16.5
20.5
24.5
28.5
32.5
36.5
40.5
AGE (YEARS)
Actual
41R1.5
37R2

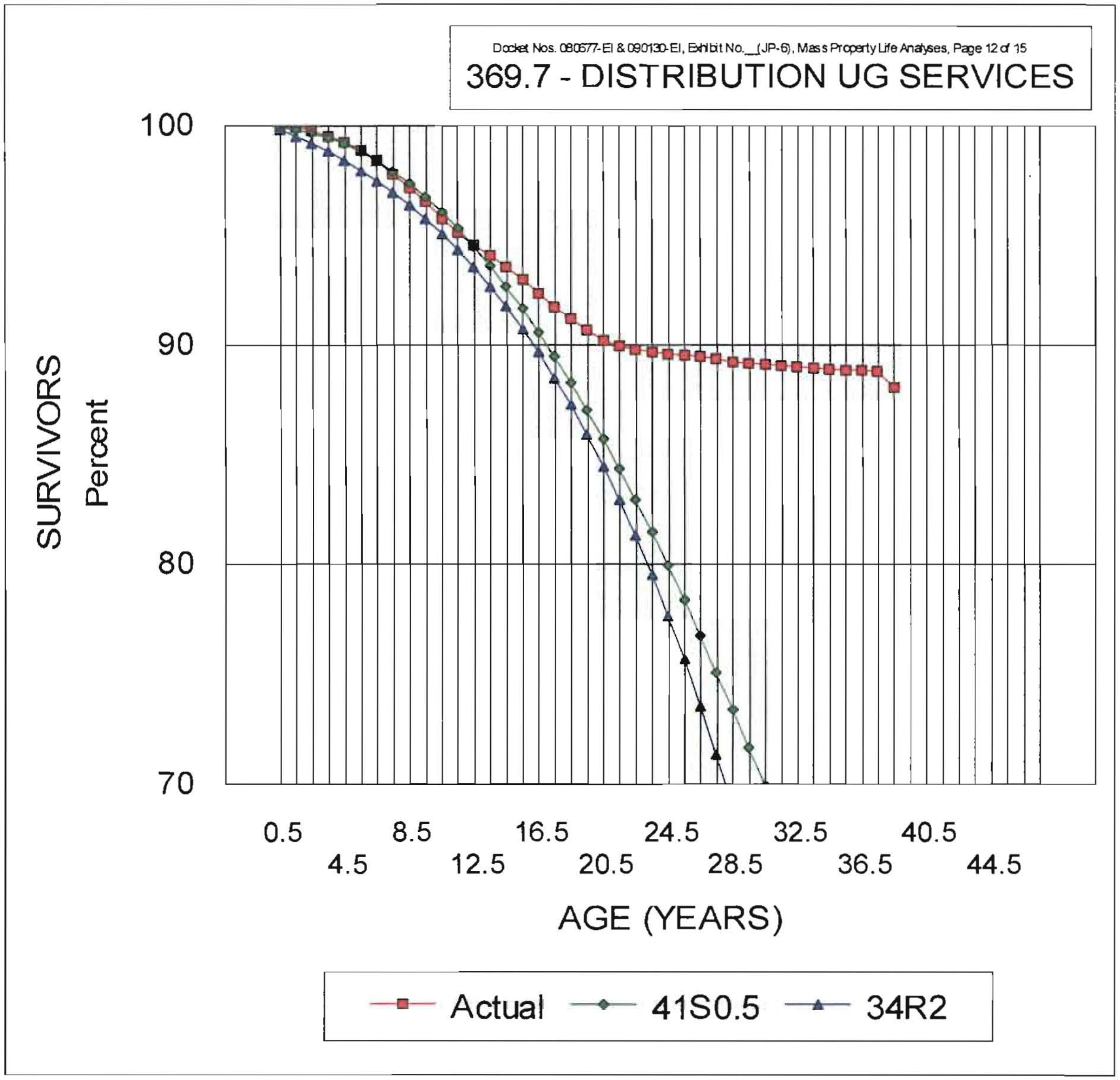

Docket Nos. 080677-EI & 090130-EI, Exhibit No.__(JP-6), Mass Property Life Analyses, Page 7 of 15
365 - DISTRIBUTION OH CONDUCTORS & DEVICES
Full Band
SURVIVORS
Percent
100
90
80
70
60
50
0.5
4.5
8.5
12.5
16.5
20.5
24.5
28.5
32.5
AGE (YEARS)
Actual
42S0
40S0

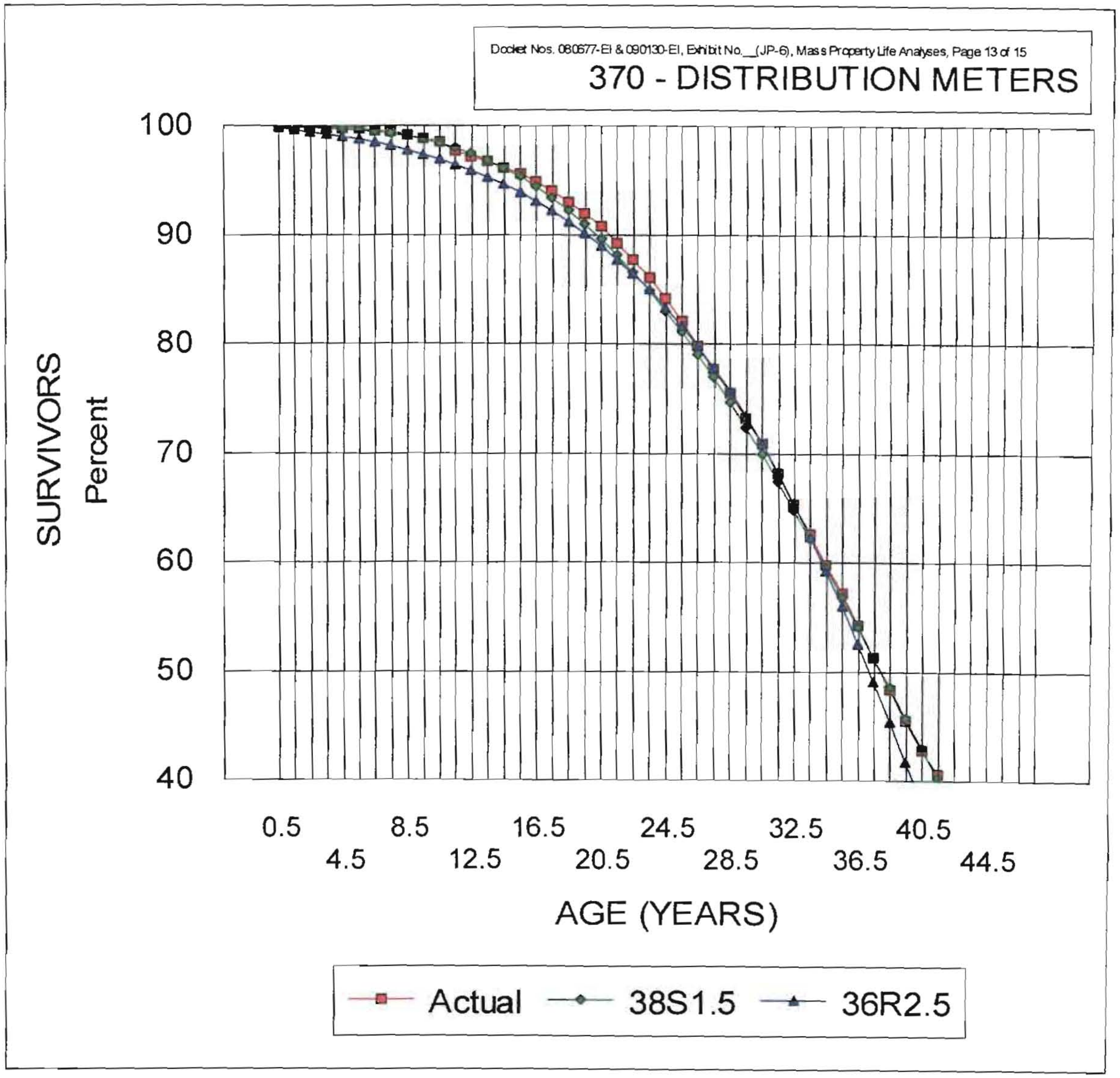

Docket Nos. 080677-EI & 090130-EI, Exhibit No.__(JP-6), Mass Property Life Analyses, Page 8 of 15
365 - DISTRIBUTION OH CONDUCTORS & DEVICES
20 Year Experience Band
SURVIVORS
Percent
100
90
80
70
60
50
40
0.5
4.5
8.5
12.5
16.5
20.5
24.5
28.5
32.5
AGE (YEARS)
Actual
46S0
40S0

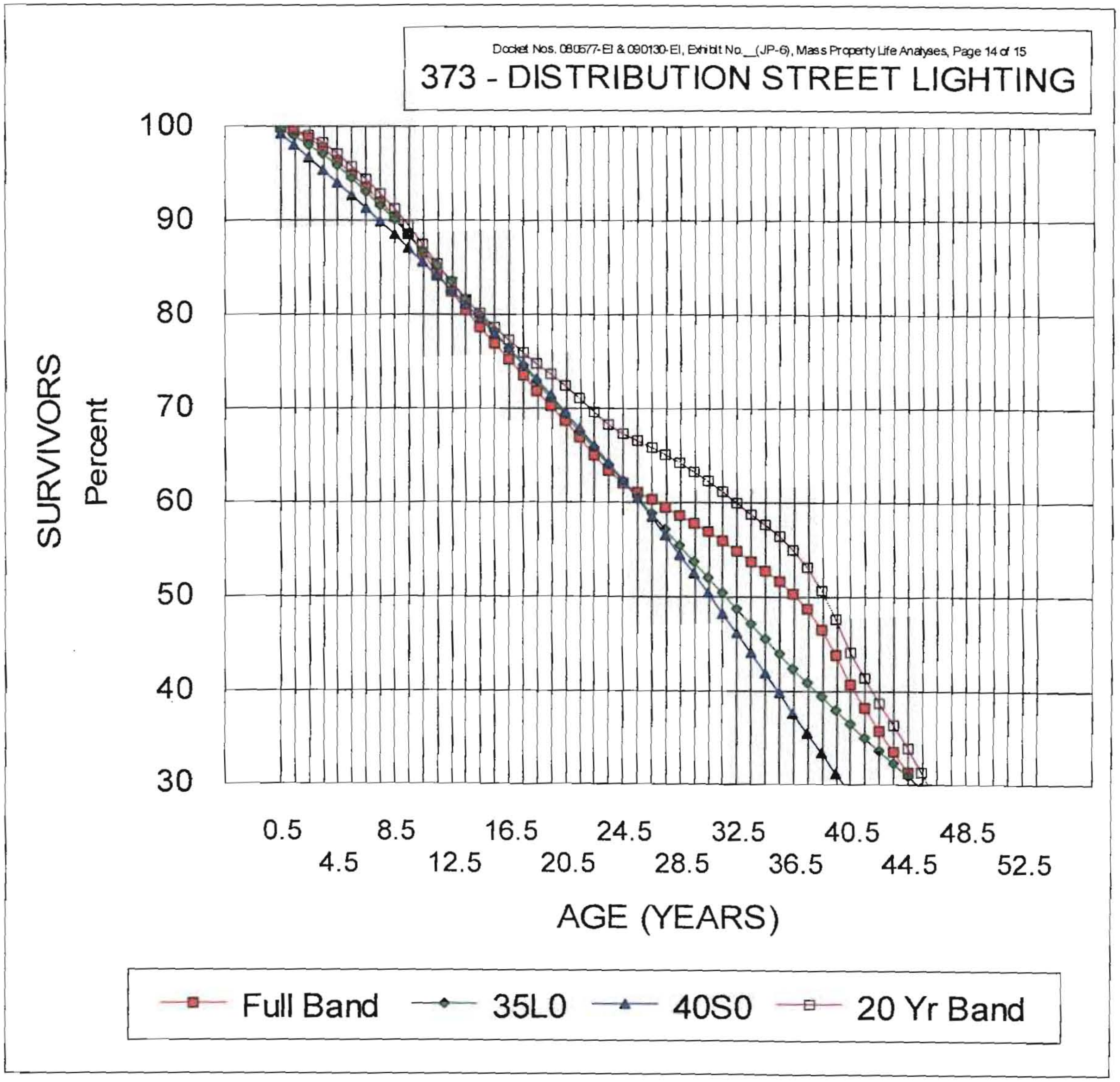

Docket Nos. 080677-EI & 090130-EI, Exhibit No.__(JP-6), Mass Property Life Analyses, Page 9 of 15
367.6 - DISTRIBUTION UG CONDUCTORS - DUCT SYSTEM
SURVIVORS
Percent
100
90
80
70
60
0.5
4.5
8.5
12.5
16.5
20.5
AGE (YEARS)
Actual
40L1
38S0

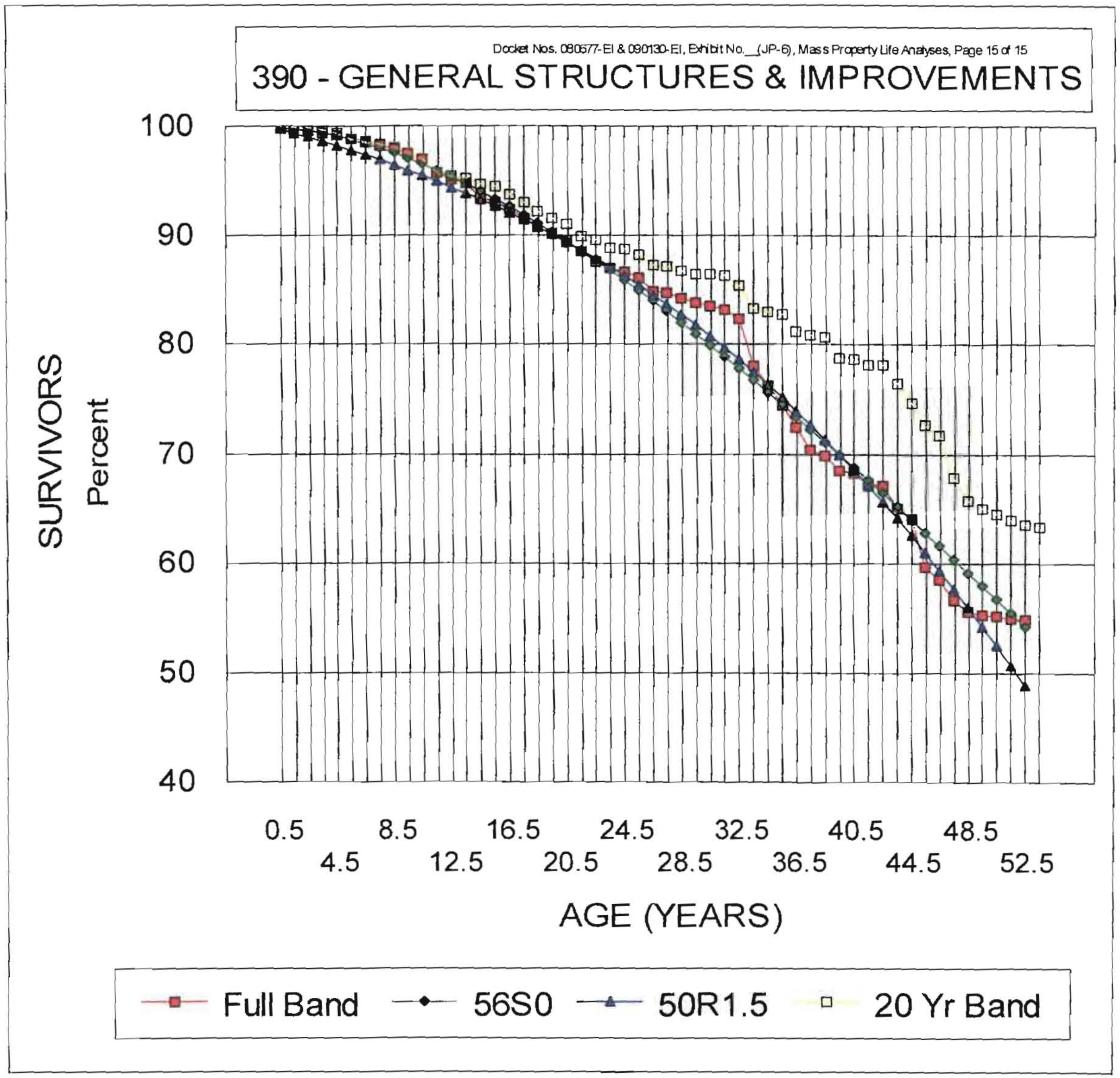

Docket Nos. 080677-EI & 090130-EI, Exhibit No.__(JP-6), Mass Property Life Analyses, Page 10 of 15
367.7 - DISTRIBUTION UG CONDUCTORS - DIRECT BURIED
100
90
80
70
60
SURVIVORS
Percent
0.5
4.5
8.5
12.5
16.5
20.5
24.5
28.5
32.5
36.5
40.5
44.5
AGE (YEARS)
Actual
43S0.5
35R2


Docket Nos. 080677-EI & 090130-EI, Exhibit No.__(JP-6), Mass Property Life Analyses, Page 11 of 15
368 - DISTRIBUTION LINE TRANSFORMERS
SURVIVORS
Percent
100
90
80
70
60
50
40
0.5
4.5
8.5
12.5
16.5
20.5
24.5
28.5
32.5
36.5
40.5
44.5
AGE (YEARS)
Actual
34L1.5
32L1.5


Docket Nos. 080677-EI & 090130-EI, Exhibit No.__(JP-6), Mass Property Life Analyses, Page 12 of 15
369.7 - DISTRIBUTION UG SERVICES
100
90
80
70
SURVIVORS
Percent
0.5
4.5
8.5
12.5
16.5
20.5
24.5
28.5
32.5
36.5
40.5
44.5
AGE (YEARS)
Actual
41S0.5
34R2


Docket Nos. 080677-EI & 090130-EI, Exhibit No.__(JP-6), Mass Property Life Analyses, Page 13 of 15
370 - DISTRIBUTION METERS
SURVIVORS
Percent
100
90
80
70
60
50
40
0.5
4.5
8.5
12.5
16.5
20.5
24.5
28.5
32.5
36.5
40.5
44.5
AGE (YEARS)
Actual
38S1.5
36R2.5


Docket Nos. 080677-EI & 090130-EI, Exhibit No.__(JP-6), Mass Property Life Analyses, Page 14 of 15
373 - DISTRIBUTION STREET LIGHTING
SURVIVORS
Percent
100
90
80
70
60
50
40
30
0.5
4.5
8.5
12.5
16.5
20.5
24.5
28.5
32.5
36.5
40.5
44.5
48.5
52.5
AGE (YEARS)
Full Band
35L0
40S0
20 Yr Band


Docket Nos. 080677-EI & 090130-EI, Exhibit No.__(JP-6), Mass Property Life Analyses, Page 15 of 15
390 - GENERAL STRUCTURES & IMPROVEMENTS
100
90
80
70
60
50
40
SURVIVORS
Percent
0.5
4.5
8.5
12.5
16.5
20.5
24.5
28.5
32.5
36.5
40.5
44.5
48.5
52.5
AGE (YEARS)
Full Band
56S0
50R1.5
20 Yr Band

COMPARISON OF NET SALVAGE %

Account	Existing	FPL Proposal	OPC Recommendation	Difference
353 Transmission Station Equipment	5	(15)	0	15
354 Transmission Tower & Fixtures	5	(15)	0	15
355 Transmission Poles & Fixtures	(50)	(50)	(30)	20
356 Transmission Overhead Conductors	(45)	(50)	(40)	10
364 Distribution Poles, Towers & Fixtures	(40)	(125)	(60)	65
365 Overhead Conductors & Devices	(50)	(100)	(50)	50
366.6 Underground Conduit – Duct System	(10)	(5)	0	5
367.6 Underground Conductor – Duct System	(5)	(5)	0	5
368 Distribution Line Transformers	(35)	(25)	(20)	5
369.1 Distribution Services - Overhead	(60)	(125)	(85)	40
369.7 Distribution Services - Underground	(10)	(10)	(5)	5
370 Distribution Meters	(30)	(55)	(10)	45
370.1 Distribution Meters – AMI	NA	(55)	(10)	45
390 General Structures & Improvements	0	(10)	25	35

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 188
COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Jacob Pous (JP-7)
DATE 08/31/09

Docket No 080677 and 090130

COMPOSITE EXHIBIT JP-8 TO PREFILED TESTIMONY OF JACOB POUS

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 189
COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Jacob Pous (JP-8)
DATE 08/31/09

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Petition for Rate Increase by
Progress Energy Florida, Inc.

Docket No. 050078-EI

DIRECT TESTIMONY OF

JACOB POUS

ON BEHALF OF

FLORIDA'S OFFICE OF PUBLIC COUNSEL
&
FLORIDA INDUSTRIAL POWER USERS GROUP

July 13, 2005

increase in plant immediately after this case ends with a short remaining life that might result in a conclusion that "your whole reserve comparison scenario [sizeable excess reserve imbalance] would just totally change" is so far beyond the realm of reality that it represents nothing more than an attempt to deny the obvious. (See Exhibit _ (JP-2), Mr. Robinson's deposition at page 75).

Q. WHAT IS YOUR SPECIFIC PROPOSAL REGARDING THE TREATMENT OF THE RESERVE EXCESS?

A. I recommend an approach that should satisfy all concerns if my recommended adjustments to mass property net salvage are adopted. Under the scenario I recommend, the $714 million plus of additional excess reserves associated with my adjustments to net salvage parameters, plus the nuclear decommissioning excess reserve of $130 million, would be returned to customers over the next 4-years. The $504 million of excess reserve identified by the Company in its own study can be returned to customers over the remaining life as it proposed. This latter aspect provides a safety cushion for those that may believe that one is necessary, while providing the most representative generation of customers available the return of a significant portion of their prior overpaid depreciation expense. This approach addresses the matching principle and its related intergenerational inequity problem, but not to the degree that this Commission has previously found appropriate in other cases. This approach also takes into account the need to gauge the impact of a shorter amortization period so as to protect the financial integrity of the Company. I have discussed the impact of my recommended adjustment with OPC's financial and accounting witnesses, who confirmed that PEF could implement my recommendation and maintain coverage ratios adequate to access the capital markets on reasonable terms and maintain an appropriate capital structure. Alternatively, if the Commission elects not to adopt my recommended net salvage adjustments, then fairness and equity demands that the $504 million reserve excess identified by PEF plus the $129 million excess in the nuclear decommissioning fund be amortized back to customers over a 4-year period. At that point, a clean slate will have been established and future customers will be charged based on the then best estimate of depreciation parameters.

Q. WHY DID YOU CHOOSE A 4-YEAR AMORTIZATION PERIOD?

A. The 4-year period is not only within the range of periods previously adopted by this Commission for other cases where a reserve deficiency was present; it also corrects the intergenerational situation in an effective and manageable manner. Further, the 4-year period provides sufficient time for the Company to gain additional experience and perform and present a new, complete and well-documented depreciation study. Finally, one must always recognize that the ratemaking process already disadvantages current customers in the intergenerational inequity scenario. Remember, those generations of customers nearer to the end of the useful life of an investment pay much less for service than do customers at the beginning of the useful life. While future customers will not see a difference in the actual product (i.e., a kwh of energy or a Kw of capacity), a

BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA, AN OKLAHOMA CORPORATION, FOR AN ADJUSTMENT IN ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA	))))))	CAUSE NO. PUD 200800144 ORDER NO.

HEARING: December 8, 2008 through December 17, 2008
Before the Commission *en banc* with Maribeth D. Snapp, Referee

APPEARANCES: Jack P. Fite, Joann T. Stevenson, Rhonda C. Ryan and Philip F. Ricketts, Attorneys for Public Service Company of Oklahoma
Elizabeth Ryan, Whitney Weingartner and William L. Humes, Assistant Attorneys General for Office of Attorney General, State of Oklahoma
Thomas P. Schroedter, Grayden Dean Luthey, Jr. and J. Fred Gist, Attorneys for Oklahoma Industrial Energy Consumers
Lenora F. Burdine and James L. Myles, Deputy General Counsels, Elizabeth J. Stefanik, Christian D. Szlichta and Don A. Schooler, Assistant General Counsels for Public Utility Division, Oklahoma Corporation Commission
Lee W. Paden, Attorney for Quality of Service Coalition
Rick D. Chamberlain, Attorney for Wal-Mart Stores East, LP
Deirdre O. Dexter, Nancy J. Siegel and Mary Lockhart, Attorneys for City of Tulsa
Robert W. Dace and Robert A. Weishaar, Jr., Attorneys for Gerdau Ameristeel Corporation

FINAL ORDER

BY THE COMMISSION:

The Corporation Commission of the state of Oklahoma ("Commission" or "OCC"), being regularly in session and the undersigned Commissioners being present and participating, there comes on for consideration and action, the application of Public Service Company of Oklahoma ("PSO" or "Company") to adjust its rates and charges for electric service in the State of Oklahoma.

PROCEDURAL HISTORY

On May 15, 2008, PSO filed with this Commission its Notice of Intent pursuant to OAC 165:70-3-7, that it intended to file an application seeking to implement a plan that would modify the rates and charges for PSO's Oklahoma jurisdictional customers.

PUBLIC SERVICE COMPANY OF OKLAHOMA

DEPRECIATION STUDY REPORT

OF

ELECTRIC PLANT IN SERVICE

AT DECEMBER 31, 2007

INTRODUCTION

This report presents the results of a depreciation study of Public Service Company of Oklahoma's (PSO) depreciable electric utility plant in service at December 31, 2007. The study was prepared by David A. Davis, Principle Regulatory Accounting Consultant at American Electric Power Service Corporation (AEPSC). The purpose of this depreciation study was to develop appropriate annual depreciation accrual rates for each of the primary plant accounts, which comprise the functional groups for which PSO computes its annual depreciation expense.

The recommended depreciation rates are based on the Average Remaining Life Method of computing depreciation. Further explanation of this method is contained in the Discussion of *Methods and Procedures Used in the Study* section of this report.

The definition of depreciation used in this Study is the same as that used by the Federal Energy Regulatory Commission (FERC) and the National Association of Regulatory Utility Commissioners:

> "Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities."

> "Service value means the difference between original cost and the net salvage value (net salvage value means the salvage value of the property retired

PUBLIC SERVICE COMPANY OF OKLAHOMA
SCHEDULE IV - GENERATION PLANT RETIREMENT DATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2007

Plant	Fuel	Year Installed	Year Retired	Life Span (Years)
Steam Production Plant				
Northeastern				
Unit 3	Coal	1979	2039	60
Unit 4	Coal	1980	2040	60
Rail Spur		1995	2040	45
Oklaunion	Coal	1986	2046	60
Comanche	Combined Cycle	1986	2024	38
Northeastern				
Unit 1	Combined Cycle	2001	2036	35
Unit 2	Gas	1970	2035	65
Riverside				
Unit 1	Gas	1974	2034	60
Unit 2	Gas	1976	2036	60
Southwestern				
Unit 1	Gas	1952	2017	65
Unit 2	Gas	1954	2019	65
Unit 3	Gas	1967	2032	65
Tulsa				
Unit 2	Gas	1963	2025	62
Unit 3 (re-started in 2006)	Gas	2006	2015	9
Unit 4	Gas	1964	2026	62
Other Production Plant				
Weleetka 4		1975	2019	44
Weleetka 5 & 6		1976	2020	44
Weleetka		1963	2020	57
Comanche		1962	2024	62
Northeastern (1&2)		1968	2036	68
Northeastern (3&4)		1980	2040	60
Riverside - Diesel		1976	2036	60
Southwestern - Diesel		1962	2032	70
Tulsa		1967	2026	59
Riverside - Gas Peaking		2008	2056	48
Southwestern - Gas Peaking		2008	2056	48

Note: Riverside and Southwestern gas peaking units were recorded in account 107, Construction Work in Progress at December 31, 2007

BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

APPLICATION OF **PUBLIC SERVICE COMPANY OF OKLAHOMA**, AN OKLAHOMA CORPORATION, FOR AN ADJUSTMENT IN ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA	))))))	CAUSE NO. **PUD 200600285** ORDER NO. **545168**

Jm

HEARING: May 1, 2, 3, 4, 7, 8 and 9, 2007
Before the Commission *en banc* with Referee Jacqueline T. Miller

APPEARANCES: David B. Dykeman and Lenora F. Burdine, Deputy General Counsels, James L. Myles and Teryl L. Williams, Assistant General Counsels for Public Utility Division, Oklahoma Corporation Commission
William L. Humes, Elizabeth Ryan and Whitney Weingartner, Assistant Attorneys General for the Office of the Attorney General
Jack P. Fite, Ann M. Coffin, James F. McNally, Jr., Bret J. Slocum, and Rhonda C. Ryan, Attorneys for Public Service Company of Oklahoma
Thomas P. Schroedter, James D. Satrom, G. Dean Luthey, Jr. and J. Fred Gist, Attorneys for Oklahoma Industrial Energy Consumers
Lee W. Paden, Attorney for Quality of Service Coalition
Glenn M. White, Robert A. Weishaar, Jr. and Vasiliki Karandrikas, Attorneys for Gerdau Ameristeel Corporation
Ron Comingdeer, Mary Kathryn Kunc and Kendall W. Parrish, Attorneys for Oklahoma Commercial Consumers Group
Cheryl A. Vaught and Scot A. Conner, Attorneys for Redbud Energy, LP
James W. George, Grace C. Wung and Gregory K. Lawrence, Attorneys for Wal-Mart Stores, Inc.
Nancy J. Siegel, General Counsel and Steve Cousparis, City Attorney, Office of the Mayor, The City of Tulsa

FINAL ORDER

PROCEDURAL HISTORY

On September 29, 2006, Public Service Company of Oklahoma ("PSO" or "Company") filed with the Corporation Commission of the State of Oklahoma ("Commission" or "OCC") its Notice of Intent pursuant to OAC 165:70-3-7, that it intended to file an application seeking to implement a plan that would modify the rates and charges for PSO's Oklahoma jurisdictional customers. On October 3, 2006, Oklahoma Industrial Energy Consumers ("OIEC") filed its Motion to Intervene. The Attorney General of Oklahoma ("AG") filed his Entry of Appearance on October 27, 2006. On November 2, 2006, the Commission issued Order No. 531708 granting the OIEC's Motion to Intervene.

t. IPP System Upgrade Credit Interest. The Commission adopts the Company's proposed level of IPP upgrade credit interest expense of $632,504 as a corresponding finding to the Commission's determination regarding IPP System Upgrade Credits.

u. Credit Line Fees.

When the Company filed its case, it reclassified $203,300 in test year credit line fee expense from "below the line" to "above the line." Aaron Rebuttal at p. 72. AEP issues commercial paper that provides low-cost short-term borrowing rates for its affiliated companies, including PSO. In order to issue the commercial paper, AEP must guarantee the availability of funds to pay off maturing series of commercial paper. To do so, AEP obtains bank credit line support for that purpose. Aaron Rebuttal at p. 72.

OCC Staff witness Mr. Thompson and AG witness Ms. Soltani recommend reversal of this adjustment. Mr. Thompson states that PSO has adequate cash working capital and AFUDC to fund its construction activities without including this short-term debt cost in cost of service. Ms. Soltani states that PSO's overall rate of return is sufficient for these purposes and this short-term debt is not included in PSO's capital structure.

The Commission adopts the AG's proposal to reverse PSO's credit line fee adjustment in the amount of $203,300 to reflect that these fees are not included in PSO's net operating income under the FERC Uniform System of Accounts. These fees represent part of the cost of borrowing money in the form of short-term debt and thus are part of interest expense. Regulators provide for the recovery of capital costs including the cost of debt and equity financing through the overall rate of return and not by including interest costs in the income statement.

v. Depreciation Expense.

(1) Production plant life spans. AG Witness Pous testified that the Company's proposal to retain the existing 42-year life span for its coal-fired generating units does not reflect the actual beliefs or expectations of its engineering department or its depreciation experts, nor does it comply with standard industry expectations or what has been testified to in other jurisdictions for affiliates of the Company. The Commission adopts the AG's position that a 60-year life span for coal-fired generation is not only appropriate, but is consonant with how the Company actually expects to operate these units. The Commission takes note of testimony received during the hearing in Cause No. PUD 200600285, that OG&E, also an electric utility serving Oklahoma, uses a 55-year life span for its coal-fired units. The effect of this adjustment is a reduction of $7,055,111, based upon plant as of the end of December 2005.

(2) Production plant net salvage. Messrs. Pous and Selecky also criticize the Company's determination of production plant net salvage value and propose a sweeping recommendation that all production plant be assigned a negative 5% net salvage value. Mr. Pous also suggests an alternate proposal that reflects a positive 10% net salvage value, which he bases on his claims that many of the Company's plants could be sold in the future.

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of Rocky Mountain Power, a Division of PacifiCorp, for Authority to Change its Depreciation Rates Effective January 1, 2008	)))))))	DOCKET NO. 07-035-13 ORDER ADOPTING AND APPROVING STIPULATION ON DEPRECIATION RATE CHANGES

ISSUED: February 4, 2008

By the Commission:

On January 15, 2008, pursuant to the Revised Scheduling Order issued October 26, 2007, the Commission held a hearing in this docket. Gregory Monson, of the law firm Stoel Rives LLP, appeared on behalf of Rocky Mountain Power (Rocky Mountain Power or the Company), Assistant Attorney General Michael Ginsberg appeared on behalf of the Utah Division of Public Utilities (Division), Assistant Attorney General Paul Proctor appeared on behalf of the Utah Committee of Consumer Services (Committee). The only other party to this docket, the Utah Association of Energy Users (UAE), did not appear at the hearing.

Rocky Mountain Power, the Division and the Committee entered into a Stipulation on Depreciation Rate Changes (Sitpulation). The Stipulation resolved all issues in this docket. The parties to the Stipulation (Stipulating Parties) represented to the Commission that UAE was aware of the Stipulation and had no objection to it. Accordingly, the purpose of the hearing was to hear evidence and argument regarding adoption and approval of the Stipulation. A copy of the Stipulation is attached to this Order.

TERMS AND CONDITIONS

Substantive Terms of the Stipulation

12. The Stipulating Parties have engaged in good faith, arms-length negotiations in an effort to resolve this matter. The retained experts of the Stipulating Parties have participated in the negotiations. The negotiations have resulted in the agreement of the Parties on the terms and conditions as set forth herein.

13. The Stipulating Parties agree that the proposed depreciation rates set forth in Schedule 1 attached hereto and incorporated herein, represent just and reasonable depreciation rates for Rocky Mountain Power in Utah commencing January 1, 2008.

14. The depreciation rates proposed in Schedule 1 result in a decrease of approximately $22.1 million in Rocky Mountain Power's annual depreciation expense in Utah based on December 31, 2006 depreciable plant balances and relative allocation factors.

15. Among significant factors involved in the changes in rates are the following major components:

a. the accrual rate for steam production is reduced as a result of a combination of generally increasing depreciation lives of steam plants to 61 years, except the Gadsby and Carbon plants that are increased to 64 years, increasing negative net salvage value from $25 to $40 per Kilowatt and including estimated production plant in service balances through December 31, 2007[1];

[1] 2007 plant balances are based on 10 months of actual additions and 2 months of estimated additions for purposes of updating remaining lives.

PUC DOCKET NO. 35763
SOAH DOCKET NO. 473-08-3436

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR AUTHORITY TO CHANGE RATES, TO RECONCILE FUEL AND PURCHASED POWER COSTS FOR 2006 AND 2007, AND TO PROVIDE A CREDIT FOR FUEL COST SAVINGS	§ § § § § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

ORDER

This Order addresses Southwestern Public Service Company's (SPS) combined base rate case and fuel reconciliation for the calendar years 2006 and 2007. The docket was processed in accordance with the applicable statutes and Public Utility Commission of Texas (Commission) rules. SPS, Commission Staff, the Office of Public Utility Counsel (OPC), Texas Industrial Energy Consumers (TIEC), the Alliance of Xcel Municipalities (AXM), Occidental Permian Ltd. (OPL), the State of Texas (State), West Texas Municipal Power Agency (WTMPA), Canadian River Municipal Water Authority (CRMWA), Texas Cotton Ginners' Association (TCGA), Golden Spread Electric Cooperative, Inc. (Golden Spread), and the International Brotherhood of Electrical Workers Local Union No. 602 (IBEW) (collectively, Signatories) filed a unanimous stipulation (Stipulation) resolving all but one issue in this proceeding. The Commission resolved the single remaining issue by answering the certified questions presented by the parties. The JD Wind Companies and W.O. Operating Company also intervened, but withdrew their interventions before the parties executed the Stipulation resolving all of the contested issues. Consistent with the Stipulation, the application of SPS is approved.

The Commission adopts the following findings of fact and conclusions of law.

I. Findings of Fact

Procedural History

1. On June 12, 2008, SPS submitted an application to the Commission seeking authority to: (a) change its rates; (b) reconcile its fuel and purchase power costs for calendar years 2006 and 2007; and (c) provide a credit for fuel cost savings.

approved in Order No. 21, SPS will refund or surcharge the difference to make the final, approved rates effective as of February 1, 2009.

15. The Signatories agreed that SPS will not file a base rate proceeding with the cities in its service territory or the Commission any earlier than February 15, 2010.

16. The Signatories agreed that during the time that the base rates resulting from the Stipulation are in effect, SPS will not seek deregulation of its rates and/or restructuring of its operations under the Public Utility Regulatory Act, TEX. UTIL. CODE ANN., Chapter 39, Title 2 (Vernon 2007 & Supp. 2008) (PURA), and unless agreed to by the parties, SPS will not file for any rate relief that may become available from Commission Project No. 36358 and/or any legislation adopted in any 2009 Legislative Session, Regular or Special, relating to rate-setting.

17. The Signatories agreed that SPS will continue with and maintain the service and spending/hiring commitments agreed to in Section 5 of the Unanimous Stipulation entered in *Application of Southwestern Public Service Company for Authority to Change Rates; Reconciliation of its Fuel Costs for 2004 and 2005; Authority to Revise the Semi Annual Formulae Originally Approved in Docket No. 27751 Used to Adjust its Fuel Factors; and Related Relief*, Docket No. 32766, Order (Jul. 27, 2007) (Docket No. 32766). No new spending and hiring commitments are required under the Stipulation in Docket No. 35763.

18. The Signatories stated that they have reached the following specific agreements as part of the overall resolution of this proceeding:

    a. Depreciation rates recommended by AXM, which are set forth in Exhibit A to the Stipulation, shall be recorded starting January 1, 2009. SPS is authorized to use vintage group accounting for Federal Energy Regulatory Commission (FERC) Accounts 391 through 398 starting January 1, 2009. SPS shall fully justify the continued use of the assumed underlying amortization period reflected in the vintage group accounting in all future rate cases for each account.

SOAH DOCKET NO. 473-08-3436
PUC DOCKET NO. 35763

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR AUTHORITY TO CHANGE RATES, TO RECONCILE ITS FUEL AND PURCHASED POWER COSTS FOR 2006 AND 2007, AND TO PROVIDE A CREDIT FOR FUEL COST SAVINGS	§ § § § § § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

DIRECT TESTIMONY AND EXHIBITS OF JACOB POUS

TABLE OF CONTENTS

coal-fired units and similarly short life spans for gas-fired units long past when it knew that these generating facilities would, and did, operate for longer life spans than originally proposed. The Company now seeks to continue its practice of forcing earlier generations of customers to pay higher levels of depreciation expense in order to reduce any risk of recovery associated with such facilities, and now to potentially provide stock holders with a windfall profit in the future. What we know today is that coal-fired generating facilities are very valuable resources. Economic theory dictates that capital intensive items that can produce a product at a low variable cost will be maintained, repaired and operated in order to maximize its economic worth. The Company's proposed increases in life spans are not a willing presentation, but rather a forced presentation. Even the Company can no longer defend its prior unrealistic short lives. The Company must be required to recognize more realistic life spans for its production investment.

D. Recommendation

Q. WHAT DO YOU RECOMMEND?

A. I recommend a conservative minimal life span for coal and gas-fired generating facilities of 60 years unless the Company provides substantive support that a particular unit will not last for 60 years.

Q. ISN'T THIS IN EFFECT ASKING THE COMPANY TO PROVE A NEGATIVE?

A. No; not at all. As I explain below in my testimony, this is simply requiring SPS to establish why its coal and gas-fired generating units should be treated differently that what others in the electric utility industry have recognized. A 60-year life span is what many other utilities are using for these assets.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. First, there can be no doubt that the trend in the industry has been for much longer life spans than originally proposed by utilities in prior decades. As shown on Attachment (JP-5) the Company employed a 35-year life span for its coal-fired units and for some of its gas-fired units in the 1980s. The Company now proposes a 20-year longer life span for its coal units and as much as a 25-year longer life span for some of its gas-fired units. These are not merely incremental increases; these are dramatic changes (i.e., 57% increase for coal units and a 71% increase for some gas units) and demonstrate the Company's inability to reasonably predict the life spans for its generating facilities.

Both the Company and I agree that the driving factor underlying the life span of generating facilities is economics. While the intuitive concept is that the physical aspects of a generating facility represent the limiting factors, in general, that is not the case. Components of the plant will wear out or break, but as long as it is economical to replace worn out or broken parts, the generating facility will continue to operate. For example, one of the largest utilities in the country has stated that it will put in whatever it takes to keep a major generating unit operating, basically forever, so long as it is economic to so do. In fact, that same company noted that it would take a disaster of galactic proportions before it would even consider the issues of "fix or retire" a major generating facility.[22]

Major utilities, operating both coal and gas-fired generating facilities are either proposing or being required by state commissions to extend the life expectancy for coal and gas-fired generating facilities to 60 years or longer. For example, in a recent case before the Oklahoma Corporation Commission, Public Service Company of Oklahoma was ordered to increase the life spans for its coal-fired generating units to 60-years.[23] In addition, in a recent case in Utah, Rocky Mountain Power, a major west coast utility, proposed lives

[22] American Electric Power Company as noted in Cause No. 200600285, a Public Service Company of Oklahoma proceeding before the Corporation Commission of the State of Oklahoma.

[23] *Id.*

Florida Power & Light

Attachment A. Calculation of Net Salvage Estimate for Generating Plants Based on Estimated Interim Net Salvage

Account	Net Salvage Estimate for Interim Retirements	Survivor Curve	Final Retirement		Total Interim Retirements as Pct of Total Retirements	Net Salvage Estimate for Interim Retirements
			Age	Pct Surviving		
(1)	(2)	(3)	(4)	(5)	(6)=100%-(5)	(7)=(2)x(6)
311 Structures & Improvements	(15)	55 - R2.5	50	64.82%	35.18%	(5)
312 Boiler Plant Equipment	(15)	40 - R2	50	27.27%	72.73%	(11)
314 Turbogenerator Units	0	40 - R1	50	33.59%	66.41%	0
315 Accessory Electric Equipment	(20)	45 - R2.5	50	40.04%	59.96%	(12)
316 Miscellaneous Equipment	(5)	40 - R2	50	27.27%	72.73%	(4)
321 Structures & Improvements	0	40 - R3	60	1.47%	98.53%	0
322 Reactor Plant Equipment	(5)	45 - R2.5	60	14.58%	85.42%	(4)
323 Turbogenerator Units	0	35 - R1	60	4.80%	95.20%	0
324 Accessory Electric Equipment	(20)	45 - R3	60	9.92%	90.08%	(18)
325 Miscellaneous Equipment	0	55 - R2.5	60	42.70%	57.30%	0
341 Structures & Improvements	(25)	25 - R5	25	53.62%	46.38%	(12)
342 Fuel Holders, Producers & Accessories	(5)	22 - R3	25	34.04%	65.96%	(3)
343 Prime Movers - General	(10)	50 - R1	25	82.67%	17.33%	(2)
344 Generators	(100)	30 - R5	25	88.60%	11.40%	(11)
345 Accessory Electric Equipment	(10)	28 - R4	25	73.37%	26.63%	(3)
346 Misc. Power Plant Equipment	0	22 - R4	25	26.59%	73.41%	0

	Transactio	Transaction	Transactio	Transaction	Adjusted ansacti	Cost of	Reuse	Final	
311	0	Regular Retirement	1986	(232,465.66)		45,331.43	(1,443,520.75)	(3,277.77)	
311	7	Outlier Retirement	1986	-		40,019.09	-	(2,500.00)	
311	0	Regular Retirement	1987	(2,389,099.20)		34,784.14	-	(791.34)	
311	7	Outlier Retirement	1987	-		31,741.65	-	-	
311	0	Regular Retirement	1988	(198,980.21)		87,150.84	-	-	
311	2	Sale	1988	-		-	-	(43,304.52)	
311	7	Outlier Retirement	1988	-		54,556.00	-	-	
311	0	Regular Retirement	1989	(536,550.22)		337,663.03	-	-	
311	7	Outlier Retirement	1989	-		76,537.89	-	-	
311	0	Regular Retirement	1990	(499,439.66)		169,949.71	-	-	
311	7	Outlier Retirement	1990	-		66,601.21	-	-	
311	0	Regular Retirement	1991	(934,096.13)		2,805,191.70	-	15,237.29	
311	7	Outlier Retirement	1991	(44,752.68)		140,390.40	-	-	
311	0	Regular Retirement	1992	(2,589,778.77)		2,285,819.94	-	(115,415.70)	
311	7	Outlier Retirement	1992	-		(597.27)	-	-	Hurricane Related
311	7	Outlier Retirement	1992	1,811.93		(33,454.84)	-	248,500.00	
311	0	Regular Retirement	1993	(2,387,133.08)		362,239.78	-	(731,654.36)	
311	7	Outlier Retirement	1993	-		75,787.01	-	(879,438.02)	Hurricane Related
311	7	Outlier Retirement	1993	(3,372,479.24)		1,463,137.24	-	-	
311	0	Regular Retirement	1994	(1,322,346.81)		154,118.81	-	(50,610.74)	
311	7	Outlier Retirement	1994	-		-	-	(289,672.88)	Hurricane Related
311	7	Outlier Retirement	1994	-		(1,272,219.71)	-	-	
311	0	Regular Retirement	1995	(3,205,112.99)		193,967.12	-	(1,480.00)	
311	7	Outlier Retirement	1995	(324,230.53)		-	-	(93,101.86)	Hurricane Related
311	7	Outlier Retirement	1995	-		(71,566.47)	-	-	
311	0	Regular Retirement	1996	(5,259,390.03)		743,470.71	-	(48,918.98)	
311	0	Regular Retirement	1997	(1,844,666.81)		184,674.33	-	30,918.98	
311	0	Regular Retirement	1998	(123,752.17)		360,496.07	-	-	
311	0	Regular Retirement	1999	(1,150,667.29)		12,255.73	-	(85,120.39)	
311	7	Outlier Retirement	1999	-		1,160,923.03	-	(45,618.80)	
311	0	Regular Retirement	2000	(1,007,290.30)		62,496.23	-	(24,160.11)	
311	7	Outlier Retirement	2000	(267,431.20)		198,055.77	-	-	
311	0	Regular Retirement	2001	(883,555.04)		81,221.24	-	-	
311	7	Outlier Retirement	2001	(8,122,414.02)		1,369,589.16	-	-	
311	0	Regular Retirement	2002	(1,000,255.46)		40,339.32	-	-	
311	7	Outlier Retirement	2002	(2,872,197.65)		1,703,841.46	-	-	
311	0	Regular Retirement	2003	(793,360.58)		114,492.07	-	(196,465.84)	
311	7	Outlier Retirement	2003	45,273.46		160,268.04	-	-	
311	0	Regular Retirement	2004	(276,882.20)		15,065.24	-	(60,082.06)	
311	7	Outlier Retirement	2004	(6,158.05)		-	-	-	Hurricane Related
311	7	Outlier Retirement	2004	(468,233.10)		114,237.74	-	-	
311	0	Regular Retirement	2005	(3,675,044.31)		17,763.02	-	(40,680.23)	
311	7	Outlier Retirement	2005	(14,311.73)		4,170.88	-	-	Hurricane Related
311	7	Outlier Retirement	2005	-		166,857.03	-	-	
311	0	Regular Retirement	2006	(1,597,081.70)		233,175.19	-	(62,066.12)	
311	7	Outlier Retirement	2006	-		(50,000.00)	-	-	
311	0	Regular Retirement	2007	(8,170,206.99)		1,091,530.94	-	(46,826.88)	
312	0	Regular Retirement	1986	(6,850,169.05)		463,022.29	(11,647.95)	(939.48)	
312	7	Outlier Retirement	1986	-		140,122.75	-	-	
312	0	Regular Retirement	1987	(2,356,417.60)		601,391.61	-	899.30	
312	7	Outlier Retirement	1987	-		177,744.02	-	-	
312	0	Regular Retirement	1988	(3,437,165.08)		3,528,398.69	(2,000.00)	-	
312	7	Outlier Retirement	1988	-		314,772.52	-	-	
312	0	Regular Retirement	1989	(5,258,423.61)		5,541,248.77	(5,358.17)	(35,952.39)	
312	7	Outlier Retirement	1989	-		193,175.50	-	(266,601.43)	
312	0	Regular Retirement	1990	(8,448,512.57)		6,833,874.23	(30,245.40)	(59,313.97)	
312	7	Outlier Retirement	1990	-		1,200,416.81	-	-	
312	0	Regular Retirement	1991	(8,550,460.55)		7,010,560.58	(24,920.97)	(38,920.25)	
312	7	Outlier Retirement	1991	(3,917,557.13)		524,150.66	(0.64)	-	
312	0	Regular Retirement	1992	(13,468,957.05)		14,422,334.17	490.00	(361,043.23)	
312	7	Outlier Retirement	1992	-		61,453.16	-	-	Hurricane Related
312	7	Outlier Retirement	1992	-		97,018.71	-	(21,015.00)	
312	0	Regular Retirement	1993	(10,510,719.95)		4,480,679.11	-	(421,726.91)	
312	7	Outlier Retirement	1993	-		6,607.05	-	(774,682.73)	Hurricane Related
312	7	Outlier Retirement	1993	(12,938,971.99)		81,443.45	-	(99,218.36)	
312	0	Regular Retirement	1994	(14,493,006.39)		3,565,899.32	-	(419,018.55)	

312	7	Outlier Retirement	1994	(77,636.10)	40,242.31	-	(64,000.00)	
312	0	Regular Retirement	1995	(15,877,870.65)	1,008,768.16	-	(116,226.48)	
312	7	Outlier Retirement	1995	(13,237.88)	-	-	-	Hurricane Related
312	0	Regular Retirement	1996	(12,426,930.41)	1,220,918.83	-	(512,965.00)	
312	0	Regular Retirement	1997	(6,703,936.58)	584,635.47	-	(11,476.09)	
312	0	Regular Retirement	1998	(2,559,856.35)	1,201,556.60	-	(981,845.07)	
312	7	Outlier Retirement	1998	(91,246.34)	-	-	-	
312	0	Regular Retirement	1999	(6,466,759.41)	318,444.87	-	(417,375.39)	
312	7	Outlier Retirement	1999	(273,469.71)	43,713.41	-	-	
312	0	Regular Retirement	2000	(7,306,173.03)	824,139.27	-	(144,650.46)	
312	7	Outlier Retirement	2000	(8,538.27)	582,861.30	-	-	
312	0	Regular Retirement	2001	(15,932,935.10)	1,909,597.50	-	(161,861.48)	
312	7	Outlier Retirement	2001	(63,024,423.24)	6,486,422.22	-	-	
312	0	Regular Retirement	2002	(6,042,747.39)	3,298,573.76	-	156,360.44	
312	7	Outlier Retirement	2002	(31,428,255.82)	7,616,364.99	-	-	
312	0	Regular Retirement	2003	(10,315,537.58)	1,030,879.68	-	(517,207.83)	
312	7	Outlier Retirement	2003	-	3,219,441.03	-	-	
312	0	Regular Retirement	2004	(13,039,108.33)	2,575,852.17	-	(1,189,498.92)	
312	7	Outlier Retirement	2004	396,153.44	(37,261.87)	-	-	
312	0	Regular Retirement	2005	(28,257,721.06)	4,014,272.18	-	(979,176.78)	
312	7	Outlier Retirement	2005	-	7,679,005.48	-	-	
312	0	Regular Retirement	2006	(22,738,441.01)	4,752,486.37	-	(633,118.68)	
312	7	Outlier Retirement	2006	(704,822.41)	202,273.00	-	-	Hurricane Related
312	7	Outlier Retirement	2006	1,044,812.67	13,427,933.80	-	-	
312	0	Regular Retirement	2007	(23,140,399.11)	6,089,599.23	(225,000.00)	(2,006,962.15)	
312	7	Outlier Retirement	2007	-	(11,578,679.48)	-	-	
314	0	Regular Retirement	1986	(1,401,002.00)	145,540.08	-	-	
314	7	Outlier Retirement	1986	-	91,667.97	-	-	
314	0	Regular Retirement	1987	(1,549,782.52)	439,940.42	-	(3,120,192.70)	
314	7	Outlier Retirement	1987	-	115,160.06	-	-	
314	0	Regular Retirement	1988	(6,700,418.83)	252,457.36	-	(3,098,000.00)	
314	7	Outlier Retirement	1988	-	195,681.41	-	-	
314	0	Regular Retirement	1989	(11,835,458.48)	1,215,525.55	(6,666.00)	(644,675.03)	
314	7	Outlier Retirement	1989	-	135,369.56	-	-	
314	0	Regular Retirement	1990	(2,058,826.38)	213,105.52	-	-	
314	7	Outlier Retirement	1990	-	254,347.00	-	-	
314	0	Regular Retirement	1991	(17,577,316.19)	555,806.18	-	-	
314	7	Outlier Retirement	1991	-	310,803.76	0.64	-	
314	0	Regular Retirement	1992	(7,459,433.46)	2,196,031.90	-	(6,739,653.80)	
314	7	Outlier Retirement	1992	(62,635.15)	(536,200.70)	-	-	
314	0	Regular Retirement	1993	(13,322,843.89)	1,036,736.23	-	(3,354,264.03)	
314	7	Outlier Retirement	1993	-	320.68	-	(35,320.68)	Hurricane Related
314	7	Outlier Retirement	1993	(2,873,471.58)	129,006.23	-	(378,327.00)	
314	0	Regular Retirement	1994	(762,721.28)	130,097.51	-	(196,918.51)	
314	7	Outlier Retirement	1994	-	1.22	-	-	
314	0	Regular Retirement	1995	(23,117,621.04)	861,346.12	-	(207,090.60)	
314	0	Regular Retirement	1996	(556,520.34)	157,251.95	-	(12,200.40)	
314	7	Outlier Retirement	1996	-	-	-	-	
314	0	Regular Retirement	1997	(626,054.12)	1,667,627.78	-	(12,200.40)	
314	0	Regular Retirement	1998	(4,622,832.38)	(60,519.85)	-	-	
314	0	Regular Retirement	1999	(494,950.55)	(1,127,201.73)	-	(82,898.17)	
314	7	Outlier Retirement	1999	-	296.11	-	-	
314	0	Regular Retirement	2000	(647,923.32)	276,549.10	-	(19,960.11)	
314	7	Outlier Retirement	2000	-	54,875.39	-	-	
314	0	Regular Retirement	2001	(2,723,649.75)	1,242,952.67	-	-	
314	7	Outlier Retirement	2001	(5,249,264.11)	457,221.84	-	-	
314	0	Regular Retirement	2002	(7,504,623.77)	445,472.61	-	-	
314	7	Outlier Retirement	2002	(4,280,072.48)	970,201.62	-	-	
314	0	Regular Retirement	2003	(3,257,050.88)	790,782.82	-	(7,882,154.40)	
314	7	Outlier Retirement	2003	-	302,492.65	-	(27,484.00)	
314	0	Regular Retirement	2004	(6,081,599.17)	1,923,051.78	-	(2,484,325.39)	
314	7	Outlier Retirement	2004	(2,602,021.18)	651,685.33	-	-	
314	0	Regular Retirement	2005	(20,778,442.00)	2,315,929.14	-	(2,849,759.51)	
314	7	Outlier Retirement	2005	-	34,839.67	-	-	
314	0	Regular Retirement	2006	(7,695,858.52)	3,017,507.53	(360,000.00)	(1,269,906.07)	
314	0	Regular Retirement	2007	(6,957,818.68)	3,693,955.02	(360,000.00)	(375,086.27)	
315	0	Regular Retirement	1986	(73,694.10)	12,620.12	-	18,000.00	
315	7	Outlier Retirement	1986	(23,267.31)	14,898.65	-	-	

315	0	Regular Retirement	1987	(404,680.01)	22,499.86	-	-	
315	7	Outlier Retirement	1987	-	7,345.87	-	-	
315	0	Regular Retirement	1988	(585,617.58)	27,431.57	-	-	
315	7	Outlier Retirement	1988	-	18,190.26	-	-	
315	0	Regular Retirement	1989	(772,715.28)	437,972.94	(13,334.00)	-	
315	7	Outlier Retirement	1989	-	16,055.35	-	-	
315	0	Regular Retirement	1990	(1,909,614.84)	235,511.21	-	(567,890.00)	
315	7	Outlier Retirement	1990	25,289.00	45,804.06	-	-	
315	0	Regular Retirement	1991	(631,033.10)	44,791.99	-	-	
315	7	Outlier Retirement	1991	(1,743.81)	62,625.39	-	-	
315	0	Regular Retirement	1992	(853,802.96)	467,384.44	-	(4,500.00)	
315	7	Outlier Retirement	1992	-	(125,462.33)	-	-	
315	0	Regular Retirement	1993	(545,964.64)	89,345.07	-	(116,317.70)	
315	7	Outlier Retirement	1993	-	451.28	-	-	Hurricane Related
315	7	Outlier Retirement	1993	(1,386,798.75)	3,105.70	-	-	
315	0	Regular Retirement	1994	(261,291.83)	130,746.58	-	(94,594.00)	
315	7	Outlier Retirement	1994	-	-	-	(2,593.11)	Hurricane Related
315	7	Outlier Retirement	1994	-	2,080.37	-	-	
315	0	Regular Retirement	1995	(692,898.47)	42,649.15	-	(4,697.70)	
315	0	Regular Retirement	1996	(934,574.99)	48,263.41	-	(6,619.76)	
315	7	Outlier Retirement	1996	-	-	-	(3,100.00)	
315	0	Regular Retirement	1997	(431,892.58)	6,408.74	-	(9,500.00)	
315	0	Regular Retirement	1998	(83,299.93)	572.96	-	-	
315	0	Regular Retirement	1999	(902,472.78)	4,483.48	-	(82,898.17)	
315	7	Outlier Retirement	1999	-	147.78	-	-	
315	0	Regular Retirement	2000	(202,184.11)	217,175.39	-	(49,960.11)	
315	7	Outlier Retirement	2000	-	20,066.11	-	-	
315	0	Regular Retirement	2001	(1,075,940.49)	351,747.54	-	-	
315	7	Outlier Retirement	2001	(4,156,979.37)	220,100.89	-	-	
315	0	Regular Retirement	2002	(681,751.22)	51,227.32	-	-	
315	7	Outlier Retirement	2002	(1,746,777.03)	246,189.81	-	-	
315	0	Regular Retirement	2003	(62,044.38)	7,212.95	-	-	
315	7	Outlier Retirement	2003	-	99,415.71	-	-	
315	0	Regular Retirement	2004	(923,709.97)	274,179.47	-	-	
315	7	Outlier Retirement	2004	(1,017,931.81)	252,494.73	-	-	
315	0	Regular Retirement	2005	(1,777,122.77)	321,181.03	-	(7,357.40)	
315	7	Outlier Retirement	2005	-	13,486.33	-	-	
315	0	Regular Retirement	2006	(3,102,721.46)	1,097,221.07	-	(38,078.60)	
315	0	Regular Retirement	2007	(2,722,835.49)	854,917.45	-	(119,800.54)	
316	0	Regular Retirement	1986	(88,376.95)	1,671.54	-	(9,240.27)	
316	7	Outlier Retirement	1986	-	4,877.99	-	-	
316	0	Regular Retirement	1987	(229,946.81)	-	-	(4,368.38)	
316	7	Outlier Retirement	1987	-	1,119.74	-	-	
316	0	Regular Retirement	1988	(97,398.92)	8,232.92	-	(600.91)	
316	7	Outlier Retirement	1988	-	19,661.52	-	-	
316	0	Regular Retirement	1989	(56,260.88)	50,173.05	(10,387.37)	(1,890.11)	
316	7	Outlier Retirement	1989	-	11,825.88	-	-	
316	0	Regular Retirement	1990	(93,816.09)	83,801.43	-	(2,056.41)	
316	7	Outlier Retirement	1990	-	29,319.55	-	-	
316	0	Regular Retirement	1991	(23,042.24)	56,687.38	-	(1,653.98)	
316	7	Outlier Retirement	1991	-	32,208.50	-	-	
316	0	Regular Retirement	1992	(182,235.52)	169,139.27	-	(20,800.20)	
316	7	Outlier Retirement	1992	(48.17)	(82,931.26)	-	-	
316	0	Regular Retirement	1993	(226,340.82)	5,246.93	(52,091.75)	(31,393.02)	
316	7	Outlier Retirement	1993	(212,438.97)	778.47	-	(7,389.65)	
316	0	Regular Retirement	1994	(199,751.78)	1,471.54	-	(626.14)	
316	7	Outlier Retirement	1994	(16,076.84)	1.22	-	-	
316	0	Regular Retirement	1995	(107,304.92)	1,139.89	-	(5,000.00)	
316	0	Regular Retirement	1996	(647,498.16)	7,662.56	-	(27,573.28)	
316	7	Outlier Retirement	1996	-	-	-	-	
316	0	Regular Retirement	1997	(3,385.22)	13,076.23	-	(3,460.00)	
316	0	Regular Retirement	1998	(1,241,230.66)	4,971.04	-	(353.65)	
316	0	Regular Retirement	1999	(256,578.49)	2,282.52	-	(86,534.17)	
316	7	Outlier Retirement	1999	-	75.80	-	-	
316	0	Regular Retirement	2000	(310,999.77)	7,660.76	-	(13,518.11)	
316	7	Outlier Retirement	2000	-	18,023.16	-	-	
316	0	Regular Retirement	2001	(281,719.06)	19,621.02	-	(8,805.00)	
316	7	Outlier Retirement	2001	(652,284.82)	131,811.96	-	-	

316	0	Regular Retirement	2002	(665,298.10)	30,318.91	-	2,500.00	
316	7	Outlier Retirement	2002	(1,144,840.14)	193,160.67	-	(2,500.00)	
316	0	Regular Retirement	2003	(133,039.95)	21,677.66	-	(2,366.80)	
316	7	Outlier Retirement	2003	-	105,430.18	-	-	
316	0	Regular Retirement	2004	(131,833.96)	-	-	-	
316	7	Outlier Retirement	2004	(61,920.30)	30,354.51	-	-	
316	0	Regular Retirement	2005	(157,241.99)	13,879.67	-	-	
316	7	Outlier Retirement	2005	-	1,685.80	-	-	
316	0	Regular Retirement	2006	(202,388.18)	(630.78)	-	(1,720.00)	
316	0	Regular Retirement	2007	(204,109.24)	39,034.21	-	(3,692.00)	
321	0	Regular Retirement	1986	(261,230.49)	381,826.45	-	(4,166.55)	
321	0	Regular Retirement	1987	(190,785.28)	127,970.92	-	(2,864.62)	
321	0	Regular Retirement	1988	(2,611,936.87)	123,069.72	-	(5,941.63)	
321	0	Regular Retirement	1989	(735,928.81)	217,092.37	(87,407.83)	(966.22)	
321	0	Regular Retirement	1990	(2,221,039.56)	795,699.46	(87,385.96)	(1,757,720.95)	
321	0	Regular Retirement	1991	(10,003,788.07)	917,286.85	(865,443.97)	54,607.32	
321	0	Regular Retirement	1992	(5,618,244.33)	973,305.45	54,796.56	76,293.31	
321	7	Outlier Retirement	1992	-	150.32	-	-	Hurricane Related
321	0	Regular Retirement	1993	(3,795,337.41)	143,740.06	-	(2,246,550.76)	
321	7	Outlier Retirement	1993	-	394,193.19	-	(1,477,711.73)	Hurricane Related
321	0	Regular Retirement	1994	(4,390,795.89)	113,404.70	(3,179.00)	(1,995,538.51)	
321	7	Outlier Retirement	1994	-	-	-	232,742.92	Hurricane Related
321	0	Regular Retirement	1995	(2,117,326.04)	192,493.99	(10,656.49)	(1,438,593.39)	
321	7	Outlier Retirement	1995	(40,953.61)	-	-	-	Hurricane Related
321	0	Regular Retirement	1996	(1,994,630.10)	55,040.43	(239,661.50)	(24,026.05)	
321	0	Regular Retirement	1997	(2,177,274.69)	77,395.92	(254,409.82)	46,070.88	
321	0	Regular Retirement	1998	(205,957.78)	-	-	1,024.49	
321	0	Regular Retirement	1999	(1,074,143.88)	84,790.32	-	(6,314.98)	
321	0	Regular Retirement	2000	(176,472.21)	314,513.23	-	(5,030.64)	
321	0	Regular Retirement	2001	(800,719.36)	29,453.65	-	(3,142.15)	
321	0	Regular Retirement	2002	(1,278,387.38)	50,132.22	-	-	
321	0	Regular Retirement	2003	(394,338.76)	25,386.86	-	(63,072.08)	
321	0	Regular Retirement	2004	(1,089,131.52)	(13,936.92)	-	(312,660.71)	
321	0	Regular Retirement	2005	(2,628,323.25)	303,479.51	-	(627,142.84)	
321	7	Outlier Retirement	2005	(3,791,128.37)	-	-	-	Hurricane Related
321	0	Regular Retirement	2006	(4,133,272.61)	355,379.71	-	(374,411.43)	
321	7	Outlier Retirement	2006	(496,656.46)	44,723.94	-	-	Hurricane Related
321	0	Regular Retirement	2007	(6,163,316.13)	1,122,175.78	-	(532,602.00)	
321	7	Outlier Retirement	2007	(541,994.66)	-	-	-	Hurricane Related
322	0	Regular Retirement	1986	4,467,648.29	1,596,468.65	-	-	
322	0	Regular Retirement	1987	(6,967,131.67)	608,951.81	-	(75,492.16)	
322	0	Regular Retirement	1988	(3,759,052.42)	(465,082.70)	-	(13,026.90)	
322	0	Regular Retirement	1989	(7,651,212.93)	676,715.19	-	(4,188.21)	
322	0	Regular Retirement	1990	(12,787,284.03)	565,953.44	-	(68,841.54)	
322	0	Regular Retirement	1991	(6,300,526.07)	1,367,402.08	(42,931.42)	(128,634.28)	
322	0	Regular Retirement	1992	(21,256,876.30)	399,394.48	(129,658.17)	(74,237.29)	
322	7	Outlier Retirement	1992	-	9,351.88	-	-	Hurricane Related
322	0	Regular Retirement	1993	(8,178,457.75)	947,259.89	(123,852.09)	(225,324.54)	
322	0	Regular Retirement	1994	(4,853,354.06)	530,628.19	(192,343.01)	(133,720.25)	
322	0	Regular Retirement	1995	(9,819,988.52)	341,342.12	(3,465,812.92)	37,905.92	
322	7	Outlier Retirement	1995	-	9,471,102.51	-	-	Steam Generator Replacement
322	0	Regular Retirement	1996	(5,305,894.52)	198,479.01	(218,124.57)	223,997.58	
322	7	Outlier Retirement	1996	-	2,442,678.58	-	-	Steam Generator Replacement
322	0	Regular Retirement	1997	(7,727,081.51)	84,124.14	-	(3,618.22)	
322	7	Outlier Retirement	1997	-	27,028,389.65	-	-	Steam Generator Replacement
322	0	Regular Retirement	1998	(3,312,286.02)	92,175.42	-	(7.75)	
322	7	Outlier Retirement	1998	(18,266,078.71)	9,951,352.92	-	-	Steam Generator Replacement
322	0	Regular Retirement	1999	(1,016,137.48)	34,909.60	-	(75.76)	
322	0	Regular Retirement	2000	(3,798,736.46)	67,223.54	-	(7,034.18)	
322	0	Regular Retirement	2001	(7,190,793.45)	44,366.76	-	(3,142.16)	
322	0	Regular Retirement	2002	(3,725,474.92)	15,185.43	-	-	
322	0	Regular Retirement	2003	(2,958,582.17)	264,445.63	-	(215,081.53)	
322	0	Regular Retirement	2004	(2,629,451.04)	281,160.40	-	-	
322	7	Outlier Retirement	2004	(2,018,259.66)	6,388,102.00	-	-	Reactor Vessel Head Replacement
322	0	Regular Retirement	2005	(10,818,073.10)	14,938,875.78	-	(1,659,986.05)	
322	7	Outlier Retirement	2005	(3,429,375.28)	14,324,419.41	-	-	Reactor Vessel Head Replacement
322	0	Regular Retirement	2006	(8,862,965.75)	1,633,675.17	-	(45,859.72)	
322	7	Outlier Retirement	2006	(3,677,774.87)	(25,756.74)	-	-	Reactor Vessel Head Replacement

322	0	Regular Retirement	2007	(24,896,169.19)	6,628,206.17	-	(6,796,965.08)	
322	7	Outlier Retirement	2007	(265,481.88)	6,388,102.00	-	-	Reactor Vessel Head Replacement
322	7	Outlier Retirement	2007	-	44,601,704.00	-	-	Steam Generator Replacement
323	0	Regular Retirement	1986	(6,200,272.24)	402,125.34	-	(10,904.77)	
323	0	Regular Retirement	1987	(8,628,305.20)	366,827.14	-	-	
323	0	Regular Retirement	1988	(1,307,005.80)	281,094.47	-	(27,652.12)	
323	0	Regular Retirement	1989	(7,824,016.74)	106,337.12	-	9,992.29	
323	0	Regular Retirement	1990	(1,914,888.40)	325,915.57	-	(61,238.72)	
323	0	Regular Retirement	1991	(2,167,400.24)	503,773.04	-	(5,837.77)	
323	0	Regular Retirement	1992	(9,194,062.39)	267,026.91	(29,333.45)	(219,288.71)	
323	0	Regular Retirement	1993	(2,567,945.84)	92,124.12	(788,856.15)	(472,851.23)	
323	0	Regular Retirement	1994	(6,991,624.66)	322,887.91	(2,127,743.22)	(3,564,910.00)	
323	7	Outlier Retirement	1994	-	-	-	(90,199.63)	Hurricane Related
323	0	Regular Retirement	1995	(8,228,581.04)	1,195,034.82	(962,619.93)	138,591.83	
323	0	Regular Retirement	1996	(2,195,141.83)	405,527.77	-	(293,320.84)	
323	0	Regular Retirement	1997	(28,637.63)	-	-	-	
323	0	Regular Retirement	1998	(1,276,277.62)	-	-	-	
323	0	Regular Retirement	1999	-	130,351.23	-	(19,416.48)	
323	0	Regular Retirement	2000	(3,351,277.88)	368,794.51	-	(29,029.79)	
323	0	Regular Retirement	2001	(812,367.79)	-	-	(3,142.16)	
323	0	Regular Retirement	2002	(61,949.95)	-	-	-	
323	0	Regular Retirement	2003	(2,986,372.79)	168,303.19	-	(5,418.42)	
323	0	Regular Retirement	2004	(1,613,262.60)	523,137.75	-	(873,029.12)	
323	0	Regular Retirement	2005	(49,210,659.09)	3,942,706.59	-	(23,396,113.76)	
323	0	Regular Retirement	2006	(6,091,921.42)	6,121,665.34	-	(4,719,474.53)	
323	0	Regular Retirement	2007	(10,924,527.89)	4,359,770.75	-	(3,512,866.03)	
324	0	Regular Retirement	1986	241,350.87	5.92	(78.00)	-	
324	0	Regular Retirement	1987	(490,199.88)	90,672.00	-	(50,565.79)	
324	0	Regular Retirement	1988	(1,644,163.14)	231,793.47	78.00	(5,048.53)	
324	0	Regular Retirement	1989	(501,380.13)	91,569.73	-	(501.63)	
324	0	Regular Retirement	1990	1,119,997.07	70,470.29	(2,854.91)	(39,347.53)	
324	0	Regular Retirement	1991	(1,096,269.54)	301,689.62	-	(8,047.51)	
324	0	Regular Retirement	1992	(3,032,499.42)	117,695.27	(3,955.80)	(105.80)	
324	7	Outlier Retirement	1992	-	1,914.73	-	-	Hurricane Related
324	0	Regular Retirement	1993	(684,374.00)	7,521.92	-	(185,005.35)	
324	0	Regular Retirement	1994	(56,587.31)	9,244.64	(21,553.00)	-	
324	7	Outlier Retirement	1994	-	-	-	(29,713.59)	Hurricane Related
324	0	Regular Retirement	1995	(184,672.71)	27,792.37	-	723.11	
324	0	Regular Retirement	1996	(1,487,379.99)	63,677.45	(20,372.63)	2,853.41	
324	0	Regular Retirement	1997	(8,447.25)	1,236.97	-	(184.25)	
324	0	Regular Retirement	1999	(185,023.88)	-	-	-	
324	0	Regular Retirement	2000	(172,936.99)	9,815.47	-	(888.59)	
324	0	Regular Retirement	2001	(320,816.58)	4,005.14	-	(3,142.16)	
324	0	Regular Retirement	2002	(846,697.24)	208,680.66	-	-	
324	0	Regular Retirement	2003	(383,027.93)	16,756.06	-	-	
324	0	Regular Retirement	2004	(300,767.04)	760,968.50	-	(22,979.93)	
324	0	Regular Retirement	2005	(1,129,441.85)	808,251.46	-	(62,555.41)	
324	0	Regular Retirement	2006	(1,559,373.71)	6,776.14	-	-	
324	0	Regular Retirement	2007	(486,493.82)	72,614.35	-	-	
325	0	Regular Retirement	1986	(8,257.75)	-	(26.00)	(1,148.07)	
325	0	Regular Retirement	1987	(165,467.07)	6,208.00	-	(13,863.31)	
325	0	Regular Retirement	1988	(214,309.77)	1,103.46	(3,050.91)	8,185.37	
325	0	Regular Retirement	1989	(165,768.15)	41,509.83	-	(389.83)	
325	0	Regular Retirement	1990	23,027.01	268.00	(15.12)	500.79	
325	0	Regular Retirement	1991	(118,885.54)	9,258.22	26.00	(1,044.77)	
325	0	Regular Retirement	1992	(1,454,433.78)	53,075.55	-	(1,193.81)	
325	0	Regular Retirement	1993	(68,933.11)	36,269.90	(38,996.29)	(770,044.03)	
325	0	Regular Retirement	1994	(254,640.98)	5,929.35	-	(5,462.85)	
325	0	Regular Retirement	1995	(158,041.86)	28,449.48	-	(182.65)	
325	0	Regular Retirement	1996	(1,966.20)	-	-	(1,257.46)	
325	0	Regular Retirement	1997	(100,845.30)	-	-	(4,420.21)	
325	0	Regular Retirement	1998	(2,245,498.87)	69,631.97	-	(353.65)	
325	0	Regular Retirement	1999	(60,411.40)	1,381.17	-	(8,435.56)	
325	0	Regular Retirement	2000	(10,191.70)	-	-	(14,500.00)	
325	0	Regular Retirement	2001	-	-	-	(3,142.16)	
325	0	Regular Retirement	2002	(93,967.62)	351.57	-	-	
325	0	Regular Retirement	2003	(93,967.62)	352.18	-	(20,000.00)	
325	0	Regular Retirement	2004	-	(22,091.05)	-	-	

325	0	Regular Retirement	2005	-	0.05	-	(0.05)	
325	0	Regular Retirement	2006	(176,636.26)	11,505.42	-	-	
325	0	Regular Retirement	2007	(223,916.95)	16,276.81	-	(4,780.18)	
341	0	Regular Retirement	1986	(5,054.00)	-	-	-	
341	0	Regular Retirement	1987	(41,533.36)	4,789.04	-	-	
341	0	Regular Retirement	1988	(69,360.32)	1,971.32	-	-	
341	0	Regular Retirement	1989	-	300.00	-	-	
341	0	Regular Retirement	1990	(39,054.45)	46,591.83	-	-	
341	0	Regular Retirement	1991	(60,416.44)	90,729.82	-	-	
341	0	Regular Retirement	1992	(141,883.03)	15,681.84	-	-	
341	0	Regular Retirement	1993	(80,241.65)	1,327.21	-	-	
341	0	Regular Retirement	1994	17,422.17	1,507,180.19	-	-	
341	0	Regular Retirement	1995	(4,413,571.16)	804.86	-	(12,500.00)	
341	0	Regular Retirement	1996	(155,004.21)	2,034.04	-	-	
341	0	Regular Retirement	1997	(122,836.47)	80,000.00	-	-	
341	0	Regular Retirement	1998	(218,927.85)	-	-	-	
341	0	Regular Retirement	2000	(191,834.19)	13,069.66	-	-	
341	0	Regular Retirement	2001	(58,936.40)	22,193.20	-	-	
341	7	Outlier Retirement	2001	-	8,669.53	-	-	
341	0	Regular Retirement	2002	(329,800.54)	6,404.43	-	(10,000.00)	
341	0	Regular Retirement	2003	-	290,976.27	-	-	
341	7	Outlier Retirement	2003	-	1,674.95	-	-	
341	0	Regular Retirement	2004	(530,380.61)	160,504.60	-	-	
341	0	Regular Retirement	2005	(153,276.34)	720,878.42	-	(17,382.00)	
341	0	Regular Retirement	2006	(239,754.12)	64,178.00	-	(4,538.76)	
341	7	Outlier Retirement	2006	(244,339.34)	29,670.00	-	-	Hurricane Related
341	0	Regular Retirement	2007	(1,118,162.95)	117,172.29	-	(1,512,326.50)	
342	0	Regular Retirement	1987	(6,000.00)	128.84	-	-	
342	0	Regular Retirement	1988	-	75.76	-	-	
342	0	Regular Retirement	1990	(60,984.00)	-	-	-	
342	0	Regular Retirement	1991	30,492.00	-	-	-	
342	0	Regular Retirement	1992	(1,975.00)	-	-	-	
342	0	Regular Retirement	1993	(564,224.08)	1,576.68	-	-	
342	0	Regular Retirement	1994	(154,023.73)	-	-	-	
342	0	Regular Retirement	1995	(2,241,443.68)	6,883.78	-	(10,000.00)	
342	0	Regular Retirement	1996	-	-	-	(5,500.00)	
342	0	Regular Retirement	1997	(369,451.12)	26,917.04	-	-	
342	0	Regular Retirement	1998	(1,244,305.60)	3,887.08	-	(87,112.50)	
342	0	Regular Retirement	1999	-	-	-	(45,360.00)	
342	7	Outlier Retirement	1999	-	4.36	-	-	
342	7	Outlier Retirement	2000	-	175.58	-	-	
342	0	Regular Retirement	2001	(1,233,296.61)	2,616.74	-	-	
342	7	Outlier Retirement	2001	(937,311.28)	4,385.11	-	-	
342	0	Regular Retirement	2002	(586,712.64)	910.90	-	-	
342	7	Outlier Retirement	2002	-	224,843.96	-	-	
342	0	Regular Retirement	2004	(531,139.02)	225,402.62	-	-	
342	0	Regular Retirement	2005	(1,757,158.40)	209,379.76	-	-	
343	0	Regular Retirement	1986	(573,198.00)	981.43	-	-	
343	0	Regular Retirement	1987	(931,730.00)	22,586.84	-	-	
343	0	Regular Retirement	1988	(2,253,091.00)	3,319.87	-	-	
343	0	Regular Retirement	1989	(1,423,526.99)	4,511.76	(334,636.87)	-	
343	0	Regular Retirement	1990	(561,622.00)	35,636.93	-	-	
343	0	Regular Retirement	1990	51,802.00	(10,275.45)	-	-	CapSpareParts
343	0	Regular Retirement	1991	(1,841,835.00)	720,955.91	-	(38,250.00)	
343	0	Regular Retirement	1991	1,753,453.00	(194,988.48)	-	38,250.00	CapSpareParts
343	0	Regular Retirement	1992	(12,430,658.60)	587,407.93	-	(19,959.40)	
343	0	Regular Retirement	1992	2,089,128.88	(23,346.34)	-	-	CapSpareParts
343	0	Regular Retirement	1993	(3,382,430.35)	44,410.64	-	(175,000.00)	
343	0	Regular Retirement	1993	116,000.00	(12,996.62)	-	50,000.00	CapSpareParts
343	0	Regular Retirement	1994	2,571,262.50	233,971.12	-	(75,000.00)	
343	0	Regular Retirement	1994	2,538,836.33	(91,357.08)	-	-	CapSpareParts
343	0	Regular Retirement	1995	(2,582,774.65)	136,041.72	-	(71,987.38)	
343	0	Regular Retirement	1995	594,071.45	(78,491.00)	-	16,380.00	CapSpareParts
343	0	Regular Retirement	1996	(4,544,243.13)	63,197.39	-	-	
343	0	Regular Retirement	1996	2,434,403.90	(33,246.71)	-	-	CapSpareParts
343	0	Regular Retirement	1997	(1,633,805.96)	98,427.40	-	(715,274.55)	
343	0	Regular Retirement	1997	1,027,857.27	(61,004.88)	-	715,274.55	CapSpareParts
343	0	Regular Retirement	1998	(4,853,356.57)	60,892.06	-	(575,000.00)	

343	0	Regular Retirement	1998	1,700,615.19	(60,832.08)	-	575,000.00	CapSpareParts
343	0	Regular Retirement	1999	(22,918,548.49)	42,909.17	-	(1,877,891.93)	
343	0	Regular Retirement	1999	22,918,548.49	(31,534.40)	-	1,877,891.93	CapSpareParts
343	0	Regular Retirement	2000	(43,926,839.10)	299,729.16	-	(11,478,183.46)	
343	0	Regular Retirement	2000	41,984,183.27	(276,695.85)	-	11,472,231.46	CapSpareParts
343	0	Regular Retirement	2001	(41,238,167.83)	1,152,716.96	-	(12,209,554.59)	
343	0	Regular Retirement	2001	40,980,232.20	(976,188.82)	-	12,180,754.59	CapSpareParts
343	7	Outlier Retirement	2001	-	58,680.25	-	-	
343	0	Regular Retirement	2002	(30,058,695.85)	1,123,670.97	-	16,350,665.69	
343	0	Regular Retirement	2002	642,094.17	-	-	137,692.00	CapSpareParts
343	0	Regular Retirement	2003	(99,999,999.99)	-	#VALUE!	-	
343	0	Regular Retirement	2003	(16,127,551.53)	2,534,635.01	-	(30,124,865.29)	
343	0	Regular Retirement	2003	5,042,574.81	(988,321.38)	-	32,609,175.46	CapSpareParts
343	0	Regular Retirement	2003	99,999,999.99	-	-	-	CapSpareParts
343	7	Outlier Retirement	2003	-	11,337.01	-	-	
343	0	Regular Retirement	2004	(99,999,999.99)	-	#VALUE!	-	
343	0	Regular Retirement	2004	(51,194,219.95)	2,946,291.96	-	(71,279,741.55)	
343	0	Regular Retirement	2004	41,610,940.19	(2,012,969.71)	-	69,985,105.65	CapSpareParts
343	0	Regular Retirement	2004	99,999,999.99	-	-	-	CapSpareParts
343	0	Regular Retirement	2005	(99,999,999.99)	-	#VALUE!	-	
343	0	Regular Retirement	2005	(44,240,585.63)	4,951,969.12	-	(55,307,746.18)	
343	0	Regular Retirement	2005	36,371,713.60	(4,006,959.88)	-	55,229,926.02	CapSpareParts
343	0	Regular Retirement	2005	99,999,999.99	-	-	-	CapSpareParts
343	7	Outlier Retirement	2005	(31,812.52)	-	-	-	Hurricane Related
343	0	Regular Retirement	2006	(99,999,999.99)	-	#VALUE!	-	
343	0	Regular Retirement	2006	(48,261,645.10)	6,304,874.05	-	(59,038,895.49)	
343	0	Regular Retirement	2006	39,295,000.72	(4,681,326.43)	-	58,521,772.34	CapSpareParts
343	0	Regular Retirement	2006	99,999,999.99	-	-	-	CapSpareParts
343	7	Outlier Retirement	2006	-	39,466.86	-	-	Hurricane Related
343	0	Regular Retirement	2007	(99,999,999.99)	-	#VALUE!	-	
343	0	Regular Retirement	2007	(47,421,618.41)	4,390,996.56	-	(74,816,145.51)	
343	0	Regular Retirement	2007	30,211,827.18	(1,978,796.82)	-	74,609,354.88	CapSpareParts
343	0	Regular Retirement	2007	99,999,999.99	-	-	-	CapSpareParts
343.2	0	Regular Retirement	1990	(51,802.00)	10,275.45	-	-	CapSpareParts
343.2	0	Regular Retirement	1991	(1,753,453.00)	194,988.48	-	(38,250.00)	CapSpareParts
343.2	0	Regular Retirement	1992	(2,089,128.88)	23,346.34	-	-	CapSpareParts
343.2	0	Regular Retirement	1993	(116,000.00)	12,996.62	-	(50,000.00)	CapSpareParts
343.2	0	Regular Retirement	1994	(2,538,836.33)	91,357.08	-	-	CapSpareParts
343.2	0	Regular Retirement	1995	(594,071.45)	78,491.00	-	(16,380.00)	CapSpareParts
343.2	0	Regular Retirement	1996	(2,434,403.90)	33,246.71	-	-	CapSpareParts
343.2	0	Regular Retirement	1997	(1,027,857.27)	61,004.88	-	(715,274.55)	CapSpareParts
343.2	0	Regular Retirement	1998	(1,700,615.19)	60,832.08	-	(575,000.00)	CapSpareParts
343.2	0	Regular Retirement	1999	(22,918,548.49)	31,534.40	-	(1,877,891.93)	CapSpareParts
343.2	0	Regular Retirement	2000	(41,984,183.27)	276,695.85	-	(11,472,231.46)	CapSpareParts
343.2	0	Regular Retirement	2001	(40,980,232.20)	976,188.82	-	(12,180,754.59)	CapSpareParts
343.2	0	Regular Retirement	2002	(642,094.17)	#VALUE!	-	(137,692.00)	CapSpareParts
343.2	0	Regular Retirement	2003	(5,042,574.81)	988,321.38	-	(32,609,175.46)	CapSpareParts
343.2	0	Regular Retirement	2003	(99,999,999.99)	-	-	-	CapSpareParts
343.2	0	Regular Retirement	2004	(41,610,940.19)	2,012,969.71	-	(69,985,105.65)	CapSpareParts
343.2	0	Regular Retirement	2004	(99,999,999.99)	-	-	-	CapSpareParts
343.2	0	Regular Retirement	2005	(36,371,713.60)	4,006,959.88	-	(55,229,926.02)	CapSpareParts
343.2	0	Regular Retirement	2005	(99,999,999.99)	-	-	-	CapSpareParts
343.2	0	Regular Retirement	2006	(39,295,000.72)	4,681,326.43	-	(58,521,772.34)	CapSpareParts
343.2	0	Regular Retirement	2006	(99,999,999.99)	-	-	-	CapSpareParts
343.2	0	Regular Retirement	2007	(30,211,827.18)	1,978,796.82	-	(74,609,354.88)	CapSpareParts
343.2	0	Regular Retirement	2007	(99,999,999.99)	-	-	-	CapSpareParts
344	0	Regular Retirement	1987	(19,368.00)	1,051.42	-	-	
344	0	Regular Retirement	1990	(198,349.71)	5,945.45	-	-	
344	0	Regular Retirement	1993	(642,207.47)	10,787.96	-	-	
344	0	Regular Retirement	1994	-	-	-	(571,395.48)	
344	0	Regular Retirement	1996	(46,002.07)	25,360.50	-	-	
344	0	Regular Retirement	2000	(247,359.72)	24,195.82	-	-	
344	0	Regular Retirement	2001	(222,746.22)	49,110.85	-	-	
344	0	Regular Retirement	2002	-	65,000.00	-	-	
344	7	Outlier Retirement	2002	-	(75,490.51)	-	-	
344	0	Regular Retirement	2003	(1,330,522.09)	1,908,061.88	-	(11,300.00)	
344	0	Regular Retirement	2004	(1,098,584.80)	2,669,039.39	-	(22,600.00)	
344	0	Regular Retirement	2005	(527,333.91)	72,463.59	-	(58,733.08)	

344	0	Regular Retirement	2006	(1,342,297.32)	1,803,702.04	-	(68,900.23)
344	0	Regular Retirement	2007	(309,718.53)	14,972.63	-	(23,116.42)
345	0	Regular Retirement	1986	(177,338.42)	1,517.17	-	-
345	0	Regular Retirement	1987	(55,870.00)	1,960.86	-	-
345	0	Regular Retirement	1988	(25,083.00)	2,234.97	-	-
345	0	Regular Retirement	1989	(13,983.00)	2,995.20	-	-
345	0	Regular Retirement	1990	(51,333.00)	751.72	-	-
345	0	Regular Retirement	1991	(76,804.00)	1,210.47	-	-
345	0	Regular Retirement	1992	(47,520.00)	727.30	-	-
345	0	Regular Retirement	1993	62,027.40	7,858.97	-	(5,250.00)
345	0	Regular Retirement	1994	(256,808.61)	4,503.64	-	(13,500.00)
345	0	Regular Retirement	1995	(74,536.13)	10,859.91	-	-
345	0	Regular Retirement	1996	(238,983.21)	4,600.33	-	-
345	0	Regular Retirement	1997	(17,354.49)	6,805.47	-	-
345	0	Regular Retirement	1999	(13,497.28)	4,343.37	-	-
345	7	Outlier Retirement	1999	-	0.55	-	-
345	0	Regular Retirement	2000	(1,357,708.59)	913.48	-	-
345	7	Outlier Retirement	2000	-	21.94	-	-
345	0	Regular Retirement	2001	(144,752.72)	17,276.97	-	-
345	7	Outlier Retirement	2001	-	548.14	-	-
345	0	Regular Retirement	2002	(376,514.06)	34,130.25	-	-
345	7	Outlier Retirement	2002	-	(1,167.02)	-	-
345	0	Regular Retirement	2003	(306,854.00)	96,796.10	-	-
345	0	Regular Retirement	2004	(452,236.71)	31,282.14	-	-
345	0	Regular Retirement	2005	(386,107.85)	17,761.57	-	(7,000.00)
345	0	Regular Retirement	2006	(27,788.43)	148.14	-	(6,000.00)
345	0	Regular Retirement	2007	(337,221.78)	91,177.23	-	(5,700.00)
346	0	Regular Retirement	1986	(13,309.92)	-	-	-
346	0	Regular Retirement	1987	(62,514.71)	-	-	-
346	0	Regular Retirement	1990	(14,175.92)	-	-	-
346	0	Regular Retirement	1991	(90,746.33)	1,000.00	-	-
346	0	Regular Retirement	1993	28,796.49	-	-	-
346	0	Regular Retirement	1994	41,732.84	-	-	-
346	0	Regular Retirement	1995	(50.00)	-	-	-
346	0	Regular Retirement	1996	-	-	-	-
346	0	Regular Retirement	1997	(54,059.72)	-	-	-
346	0	Regular Retirement	2000	(14,010.82)	1,500.53	-	-
346	0	Regular Retirement	2001	(131,414.19)	1,653.45	-	(1,500.00)
346	7	Outlier Retirement	2001	-	100.32	-	-
346	0	Regular Retirement	2003	-	730.66	-	-
346	7	Outlier Retirement	2003	-	19.40	-	-
346	0	Regular Retirement	2004	(174,374.12)	-	-	-
346	0	Regular Retirement	2005	(134,226.18)	7,252.82	-	-
346	0	Regular Retirement	2006	(178,939.13)	2,268.71	-	-
346	0	Regular Retirement	2007	(118,268.84)	1,049.57	-	-

Q.

Industry Service Lives/Salvage. Regarding the statement on page I-2 of Exhibit CRC-1 relating to knowledge of service life and salvage estimates used for other electric properties, please provide the following:

a. Identify each separate life and or salvage for each of the other electric properties along with the identity of the source (e.g. a 10-year life was observed for company "X" & "Y" and company "Z" had a 12-year life, etc.)
b. The accounts to which each item of comparative data applied;
c. The identity of the source of the information and a complete copy of the corresponding source;
d. A detailed narrative setting forth why each life and or salvage estimate from each other electric properties were applicable to FPL's specific account to which they were applied;
e. The impact that each such individual item of knowledge had in the development of each separate life and or salvage parameter.

A.

a. The utility statistics that were used in this depreciation study are provided in Attachment No. 1 to this interrogatory.

b. Comparisons were made for all of Florida Power & Light's accounts.

c. See Attachment No. 1 to this interrogatory.

d. The estimates of other utilities were not considered individually, but rather were considered as a whole. That is, the estimates of others were used to establish a range of reasonableness against which the historical and other Company-specific indications of service life and net salvage percentages could be compared.

e. The life and net salvage of other utilities were used as comparisons and reasonableness for the estimates established for Florida Power & Light Company by the consultant and are described in each of the account write-ups presented in the depreciation report (Exhibit CRC-1).

Also see FPL's response provided in OPC's First Request for Production of Documents No. 12 "Depr-OPC 1st Set of POD No 12, 1 of 5.xls".

SUMMARY OF SERVICE LIFE RECOMMENDATIONS

Client		Jackson Energy Cooperative	Alliant	Dominion - Virginia Power	Bonneville Power Administration	Sierra Pacific Electric Company	Reliant Energy	PPL Electric Corporation
Depreciation Method		SL Rem Life	SL Rem Life		SL Rem Life	SL Rem. Life.	SL Rem Life	SL Rem Life
Purpose of Study								
Study Data Year		1999	2000	2001	1998	2005	2002	2004
FERC Account								
Account No.	Description							
Production Plant								
310 - 316	Steam Production							
310	Steam Production - Land and Land Rights		Non Depr					
310.1	Steam Production - Land and Land Rights - Land							
310.2	Steam Production - Land and Land Rights - Land Rights					75-R3		
311	Steam Production - Structures and Improvements		100-S2*			122-R2		
312	Steam Production - Boiler Plant Equipment		75-S2*			60-R2		
312.2	Steam Production - Boiler Plant Equipment - Coal Cars							
312.3	Steam Production - Boiler Plant Equipment - Scrubbers							
313	Engines and Engine Driven Generators							
314	Steam Production - Turbogenerator Units		75-S3*			70-R2		
315	Steam Production - Accessory Electric Equipment		65-R4*			60-S1.5		
316	Steam Production - Miscellaneous Power Plant Equipment		60-S1.5*			50-R1.5		
316.1	Steam Production - Miscellaneous Power Plant Equipment - Shop							
316.2	Steam Production - Miscellaneous Power Plant Equipment - Other							
320 - 325	Nuclear Production							
320	Nuclear Production - Land and Land Rights							
320.1	Nuclear Production - Land and Land Rights - Land							
320.2	Nuclear Production - Land and Land Rights - Land Rights							
321	Nuclear Production - Structures and Improvements							
322	Nuclear Production - Reactor Plant Equipment							
322.1	Nuclear Production - Reactor Plant Equipment - Steam Generators							
323	Nuclear Production - Turbogenerator Units							
324	Nuclear Production - Accessory Electric Equipment							
325	Nuclear Production - Miscellaneous Power Plant Equipment							
330 - 336	Hydraulic Production							
330	Hydraulic Production -Land and Land Rights							
330.1	Hydraulic Production -Land and Land Rights - Land							
330.2	Hydraulic Production -Land and Land Rights - Land Rights					120-S4		
331	Hydraulic Production - Structures and Improvements					100-S1		
332	Hydraulic Production - Reservoirs, Dams and Waterways					70-R1		
333	Hydraulic Production - Water Wheels, Turbines and Generators					65-R1.5		
334	Hydraulic Production - Accessory Electric Equipment					55-S3		
335	Hydraulic Production - Miscellaneous Power Plant Equipment					50-S2.5		
336	Hydraulic Production - Roads, Railroads and Bridges					55-R3		
340 - 346	Other Production							
340 - 346	Other Production - Solar							
340	Other Production -Land and Land Rights		Non Depr					
340.1	Other Production -Land and Land Rights - Land							
340.2	Other Production -Land and Land Rights - Land Rights							
341	Other Production - Structures and Improvements		40-S4*			SQ		
342	Other Production - Fuel Holders, Producers and Accessories		48-R1.5*			SQ		
343	Other Production - Prime Movers		38-L4*			SQ		
343.1	Other Production - Prime Movers - Fuel Cells							
343.2	Other Production - Prime Movers - Base Load							
343.3	Other Production - Prime Movers - Peakers							
344	Other Production - Generators		60-S2.5*			SQ		
345	Other Production - Accessory Electric Equipment		28-R2.5*			SQ		
346	Other Production - Miscellaneous Power Plant Equipment		22-S2.5*			SQ		
Transmission Plant								
350	Land and Land Rights		Non Depr		Non Depr			
350.1	Land and Land Rights - Land			Non Depr				Non Depr
350.2	Land and Land Rights - Land Rights			70-R3	75-R4	70-R4	75-R4	70-R4
352	Structures and Improvements		46-R2	50-S4	60-R2.5	55-R4	50-R4	50-R3
352.1	Structures and Improvements - Major							
352.2	Structures and Improvements - Small							
353	Station Equipment		38-R0.5	40-R1.5		50-R3	40-R2	40-R1
353.2	Station Equipment - Power Supply Company				10-S4			
353	Station Equipment - 1970 & Prior				39-S0			
353	Station Equipment - 1971 & Subsequent				34-R2.5			
353.1	Station Equipment - Substation on Customer Premises				28-R1.5			
353.2	Station Equipment - Portable Property at Substations				40-SQ			
353.3	Station Equipment - Metering Station				32-R0.5			
353.4	Station Equipment - Control Equipment (SCADA)				13-R2.5			
354	Towers and Fixtures		65-R4	70-R3	65-R3	60-R4	56-R3	60-R3

SUMMARY OF SERVICE LIFE RECOMMENDATIONS

Client		Jackson Energy Cooperative	Alliant	Dominion - Virginia Power	Bonneville Power Administration	Sierra Pacific Electric Company	Reliant Energy	PPL Electric Corporation
Depreciation Method		SL Rem Life	SL Rem Life		SL Rem Life	SL Rem. Life.	SL Rem Life	SL Rem Life
Purpose of Study								
Study Data Year		1999	2000	2001	1998	2005	2002	2004
	FERC Account							
Account No.	Description							
354.1	Towers and Fixtures - Clearing Right of Way			70-R3				70-R4
355	Poles and Fixtures		45-R1.5	55-R3	50-R2	60-R3	31-R0.5	44-R1.5
355.1	Poles and Fixtures - Clearing of Right of Way			70-R3				70-R4
355.2	Poles and Fixtures - Wood							
355.3	Poles and Fixtures - Steel							
356	Overhead Conductors and Devices		45-R2.5	55-R3	50-R4	55-R4	38-R2.5	50-S2
356.1	Overhead Conductors and Devices - Clearing of Rights of Way							
357	Underground Conduit			50-S3		60-S4	55-R4	50-R4
358	Underground Conductors and Devices		30-S2	30-S3	30-S3	50-S3	55-R4	35-S3
358.1	Underground Conductors and Devices - Submarine							
359	Roads and Trails			70-R3	74-R4	70-R4	75-SQ	70-R4
Distribution Plant								
360	Land and Land Rights		Non Depr					
360.1	Land and Land Rights - Land			Non Depr				Non Depr
360.2	Land and Land Rights - Land Rights			70-S4		65-R4	74-R4	60-R3
361	Structures and Improvements		46-R2	32-S2		55-R3	50-S3	60-R2.5
361.1	Structures and Improvements - Major							
361.2	Structures and Improvements - Small							
362	Station Equipment		21-S1.5	44-O1		50-R4	40-R2	47-R2
362.1	Station Equipment - Company Stations							
362.2	Station Equipment - Customer High Tension							
362.3	Station Equipment - SCADA							
364	Poles, Towers and Fixtures	28-L1.5	40-R1.5	30-R1.5		45-R0.5	23-R2	
364.1	Poles, Towers and Fixtures - Clearing Right of Way			30-R1.5				
364.2	Poles, Towers and Fixtures - Towers							55-R3
364.4	Poles, Towers and Fixtures - Poles							40-O1
364.6	Poles, Towers and Fixtures - Clearing Towers							50-S3
364.8	Poles, Towers and Fixtures - Clearing Poles							60-R3
364.9	Poles, Towers and Fixtures - Wood							
364.10	Poles, Towers and Fixtures - Steel							
365	Overhead Conductors and Devices	35-R1	36-R1	37-R1.5		55-R2.5	24-R2	41-R1.5
365.1	Sodium Vapor Security Lights		15-R1					55-S1.5
365.2	Overhead Conductors and Devices - Clearing Rights of Way							
366	Underground Conduit	50-S2	34-S2			60-S2	51-S1.5	
366.1	Underground Conduit - Not encased			53-R2				
366.2	Underground Conduit - Manholes and Vaults			55-R2				
366.3	Underground Conduit - Encased			60-S1				
367	Underground Conductors and Devices	30-R2	36-S1.5	29-R0.5		50-S2.5	29-R0.5	39-S1.5
367.1	Underground Conductors and Devices - Clearing Right of Way			38-R2				
368	Line Transformers	38-R1	31-S0.5	32-R0.5		45-R0.5	26-R1.5	
368.1	Line Transformers - Pole Top							34-SQ
368.2	Line Transformers - Pad Mounted							48-SQ
368.3	Line Transformers - Non-Network Housing							35-SQ
368.4	Line Transformers - Network							
368.5	Line Transformers - Underground Residential Distribution							
369	Services	27-L0	39-R1			40-R2	22-S2.5	34-R2
369.1	Services - Overhead			29-S2				
369.2	Services - Underground			29-S2				
370	Meters	36 R1.5	43-S2	25-S0		33-R1.5	25-S1	28-SQ
370.2	Meters - AMR and Electronic							15-SQ
371	Installations on Customer Premises	23-R1	20-R3	25-R2		25-R2.5		30-R3
371.2	Installations on Customer Premises - Area Lighting							17-L0.5
372	Leased Property on Customer Premises							
373	Street Lighting and Signal Systems	23-R1	22-L1	23-R0.5		35-R2	27-S0	26-S1
373.1	Street Lighting and Signal Systems - Clearing			23-R0.5				
373.2	Street Lighting and Signal Systems - M.V.							
373.3	Street Lighting and Signal Systems - H.P.S.							
General and Intangible Plant								
301	Organization							Non Depr
302	Franchises and Consents		Non Depr	5 - 25 SQ				Non Depr
303	Intangible Plant		Non Depr	Non Depr	40-SQ	10-SQ		
303.1	Intangible Plant - Software							5-SQ
303.2	Intangible Plant - Fiber Optic							15-SQ
389	Land and Land Rights	Non Depr	Non Depr					

SUMMARY OF SERVICE LIFE RECOMMENDATIONS

Client		Jackson Energy Cooperative	Alliant	Dominion - Virginia Power	Bonneville Power Administration	Sierra Pacific Electric Company	Reliant Energy	PPL Electric Corporation
Depreciation Method		SL Rem Life	SL Rem Life		SL Rem Life	SL Rem. Life.	SL Rem Life	SL Rem Life
Purpose of Study								
Study Data Year		1999	2000	2001	1998	2005	2002	2004
FERC Account								
Account No.	Description							
389.1	Land and Land Rights - Land			Non Depr				Non Depr
389.2	Land and Land Rights - Land Rights			65-R4	75-R4		55-R4	65-R4
390	Structures and Improvements	45-50 SQ			60-R2	45-R2.5	40-R2.5	
390.1	Structures and Improvements - Leasehold Improvements		20-S3					
390	Structures and Improvements - Major			90-S1.5*				60-S0*
390	Structures and Improvements - Other (Small)			45-R3				45-R3
391	Office Furniture and Equipment			15-SQ			10-SQ	
391	Office Furniture and Equipment - Equipment	5-SQ	20-SQ					15-SQ
391	Office Furniture and Equipment - Furniture	25-SQ	20-SQ		20-SQ	20-SQ		20-SQ
391	Office Furniture and Equipment - Hardware (PCs)	10-SQ	5-SQ	5-SQ	5-SQ	5-SQ	6-SQ	5-SQ
391	Office Furniture and Equipment - Software	5-SQ			5-SQ			
392	Transportation Equipment			10-L1	10-L3	Various		
392.1	Transportation Equipment - Cars	5-S3	15				5-S2	
392.2	Transportation Equipment - Light Trucks	7-R3	9-L2.5				10-S1	
392.21	Transportation Equipment - Pickup Trucks							
392.3	Transportation Equipment - Heavy Trucks	10-L2						
392.4	Transportation Equipment - Airplanes and Helicopters				15-SQ			
392.5	Transportation Equipment - Trailers							14-L0
392.6	Transportation Equipment - Other							
393	Stores Equipment	20-SQ	25-SQ	25-SQ	30-SQ	20-SQ	15-SQ	25-SQ
394	Tools, Shop and Garage Equipment	20-SQ	25-SQ	25-SQ	25-SQ	25-SQ	20-SQ	20-SQ
394.1	Tools, Shop and Garage Equipment - Electric Vehicles			10-SQ				
395	Laboratory Equipment	15-SQ	15-SQ	25-SQ	15-SQ	15-SQ	20-SQ	20-SQ
396	Power Operated Equipment	12-L2	11-L4	10-L2	15-L2	Various	14-S1.5	
397	Communication Equipment	10-SQ	15-SQ	15 - 25 SQ	15-SQ	15-SQ	15-SQ	15-SQ
397.1	Communication Equipment - Trans Line				40-S4			
397.2	Communication Equipment - EMS							
397.3	Communication Equipment - Fiber Optic							
398	Miscellaneous Equipment	15-SQ	10-SQ	25-SQ	15-SQ		10-SQ	20-SQ
399	Other Tangible Property							

SUMMARY OF SERVICE LIFE RECOMMENDATIONS

Client		Owen Electric Cooperative	Oklahoma Gas and Eclectic	Oklahoma Gas and Electric (Holding Co.)	Cincinnati Gas and Electric Company	Arizona Public Service Company	AmerenUE
Depreciation Method		SL Rem Life	SL Rem Life	SL Rem Life	SL Rem Life	SL Rem Life	SL Whole Life (w/ 20Yr.True-up)
Purpose of Study							
Study Data Year		1995	2002	2002	2003	2002	2000
FERC Account							
Account No.	Description						
Production Plant							
310 - 316	Steam Production						
310	Steam Production - Land and Land Rights					Non Depr	Non Depr
310.1	Steam Production - Land and Land Rights - Land		Non Depr				
310.2	Steam Production - Land and Land Rights - Land Rights		100-S4*		75-R4		
311	Steam Production - Structures and Improvements		100-R2.5*		100-R2.5*	75-S1.5*	120-S0*
312	Steam Production - Boiler Plant Equipment		90-R2*		55-S0.5*	48-L2*	60-S0*
312.2	Steam Production - Boiler Plant Equipment - Coal Cars						22-R3
312.3	Steam Production - Boiler Plant Equipment - Scrubbers						
313	Engines and Engine Driven Generators						
314	Steam Production - Turbogenerator Units		75-S1.5*		55-R1.5*, 55-R2.5* (Zim	65-R2*	100-S0*
315	Steam Production - Accessory Electric Equipment		60-R3*		55-R2.5*	60-R2.5*	80-R2*
316	Steam Production - Miscellaneous Power Plant Equipment		30-S0*		75-R1*	40-R2*	70-L0*
316.1	Steam Production - Miscellaneous Power Plant Equipment - Shop				37-S0.5*		
316.2	Steam Production - Miscellaneous Power Plant Equipment - Other						
320 - 325	Nuclear Production						
320	Nuclear Production - Land and Land Rights					Non Depr	Non Depr
320.1	Nuclear Production - Land and Land Rights - Land						
320.2	Nuclear Production - Land and Land Rights - Land Rights						
321	Nuclear Production - Structures and Improvements					65-R2.5*	100-R1*
322	Nuclear Production - Reactor Plant Equipment					70-R1*	60-S0*
322.1	Nuclear Production - Reactor Plant Equipment - Steam Generators					SQUARE*	
323	Nuclear Production - Turbogenerator Units					60-S0*	100-S0*
324	Nuclear Production - Accessory Electric Equipment					45-R3*	80-R2*
325	Nuclear Production - Miscellaneous Power Plant Equipment					35-R0.5*	70-L0*
330 - 336	Hydraulic Production						
330	Hydraulic Production -Land and Land Rights					Non Depr	Non Depr
330.1	Hydraulic Production -Land and Land Rights - Land						
330.2	Hydraulic Production -Land and Land Rights - Land Rights						
331	Hydraulic Production - Structures and Improvements					SQUARE*	160-R1*
332	Hydraulic Production - Reservoirs, Dams and Waterways					SQUARE*	200-SQ*
333	Hydraulic Production - Water Wheels, Turbines and Generators					SQUARE*	130-S0*
334	Hydraulic Production - Accessory Electric Equipment					SQUARE*	70-R1.5*
335	Hydraulic Production - Miscellaneous Power Plant Equipment					SQUARE*	60-R0.5*
336	Hydraulic Production - Roads, Railroads and Bridges					SQUARE*	200-SQ*
340 - 346	Other Production						
340 - 346	Other Production - Solar					12-SQ	
340	Other Production -Land and Land Rights					Non Depr	Non Depr
340.1	Other Production -Land and Land Rights - Land						
340.2	Other Production -Land and Land Rights - Land Rights				40-SQ		
341	Other Production - Structures and Improvements		SQ*		SQUARE*	80-S1*	30-SQ
342	Other Production - Fuel Holders, Producers and Accessories		SQ*		SQUARE*	70-S1*	30-SQ
343	Other Production - Prime Movers		SQ*		SQUARE*	70-L1.5*	
343.1	Other Production - Prime Movers - Fuel Cells						
343.2	Other Production - Prime Movers - Base Load						
343.3	Other Production - Prime Movers - Peakers						
344	Other Production - Generators		42-S3*		70-R2.5*	37-R3*	30-SQ
345	Other Production - Accessory Electric Equipment		28-S2*		55-S0.5*	50-S2*	30-SQ
346	Other Production - Miscellaneous Power Plant Equipment		25-S2.5*		30-S3*	70-L1*	30-SQ
Transmission Plant							
350	Land and Land Rights					Non Depr	Non Depr
350.1	Land and Land Rights - Land		Non Depr				
350.2	Land and Land Rights - Land Rights		75-R4				
352	Structures and Improvements		65-S4			50-R4	60-R2
352.1	Structures and Improvements - Major						
352.2	Structures and Improvements - Small						
353	Station Equipment		50-S2.5			42-R3	55-R2.5
353.2	Station Equipment - Power Supply Company				55-R1		
353	Station Equipment - 1970 & Prior						
353	Station Equipment - 1971 & Subsequent						
353.1	Station Equipment - Substation on Customer Premises						
353.2	Station Equipment - Portable Property at Substations						
353.3	Station Equipment - Metering Station						
353.4	Station Equipment - Control Equipment (SCADA)						
354	Towers and Fixtures		65-S4			60-R3	65-R4

SUMMARY OF SERVICE LIFE RECOMMENDATIONS

Client		Owen Electric Cooperative	Oklahoma Gas and Eclectic	Oklahoma Gas and Electric (Holding Co.)	Cincinnati Gas and Electric Company	Arizona Public Service Company	AmerenUE
Depreciation Method		SL Rem Life	SL Rem Life	SL Rem Life	SL Rem Life	SL Rem Life	SL Whole Life (w/ 20Yr.True-up)
Purpose of Study							
Study Data Year		1995	2002	2002	2003	2002	2000
	FERC Account						
Account No.	Description						
354.1	Towers and Fixtures - Clearing Right of Way						
355	Poles and Fixtures		50-R1.5				53-R4
355.1	Poles and Fixtures - Clearing of Right of Way						
355.2	Poles and Fixtures - Wood					48-R1.5	
355.3	Poles and Fixtures - Steel					55-R3	
356	Overhead Conductors and Devices		50-S2			55-R3	55-R4
356.1	Overhead Conductors and Devices - Clearing of Rights of Way						
357	Underground Conduit					48-S1.5	
358	Underground Conductors and Devices		42-R1.5			40-R3	
358.1	Underground Conductors and Devices - Submarine						
359	Roads and Trails						50-SQ
Distribution Plant							
360	Land and Land Rights					Non Depr	Non Depr
360.1	Land and Land Rights - Land		Non Depr				
360.2	Land and Land Rights - Land Rights		65-R4				
361	Structures and Improvements		65-R4			45-R2.5	60-R2.5
361.1	Structures and Improvements - Major						
361.2	Structures and Improvements - Small						
362	Station Equipment		52-R4			38-S0	55-R2.5
362.1	Station Equipment - Company Stations						
362.2	Station Equipment - Customer High Tension						
362.3	Station Equipment - SCADA						
364	Poles, Towers and Fixtures	44-R0.5	45-S0.5				43-R3
364.1	Poles, Towers and Fixtures - Clearing Right of Way						
364.2	Poles, Towers and Fixtures - Towers						
364.4	Poles, Towers and Fixtures - Poles						
364.6	Poles, Towers and Fixtures - Clearing Towers						
364.8	Poles, Towers and Fixtures - Clearing Poles						
364.9	Poles, Towers and Fixtures - Wood					38-R0.5	
364.10	Poles, Towers and Fixtures - Steel					50-R3	
365	Overhead Conductors and Devices	37-L2	48-R2			53-O1	47-R1
365.1	Sodium Vapor Security Lights						
365.2	Overhead Conductors and Devices - Clearing Rights of Way						
366	Underground Conduit		55-R3			55-R1.5	65-R3
366.1	Underground Conduit - Not encased						
366.2	Underground Conduit - Manholes and Vaults						
366.3	Underground Conduit - Encased						
367	Underground Conductors and Devices	25-R3	50-S1			29-L1	53-R2
367.1	Underground Conductors and Devices - Clearing Right of Way						
368	Line Transformers	37-R1.5	35-R0.5			36-R3	40-SQ
368.1	Line Transformers - Pole Top						
368.2	Line Transformers - Pad Mounted						
368.3	Line Transformers - Non-Network Housing						
368.4	Line Transformers - Network						
368.5	Line Transformers - Underground Residential Distribution						
369	Services	36-R0.5	45-R2			37-S2	
369.1	Services - Overhead						36-R3
369.2	Services - Underground						45-R3
370	Meters	33-R3	31-R3			23-R1	30-SQ
370.2	Meters - AMR and Electronic					12-S2	
371	Installations on Customer Premises	28-R1				30-R1	20-O1
371.2	Installations on Customer Premises - Area Lighting						
372	Leased Property on Customer Premises						
373	Street Lighting and Signal Systems	28-R1	31-R3			35-R2	32-L1
373.1	Street Lighting and Signal Systems - Clearing						
373.2	Street Lighting and Signal Systems - M.V.						
373.3	Street Lighting and Signal Systems - H.P.S.						
General and Intangible Plant							
301	Organization		Non Depr				
302	Franchises and Consents		Non dear				
303	Intangible Plant		5-SQ				
303.1	Intangible Plant - Software						
303.2	Intangible Plant - Fiber Optic						
389	Land and Land Rights					Non Depr	Non Depr

SUMMARY OF SERVICE LIFE RECOMMENDATIONS							
Client		Owen Electric Cooperative	Oklahoma Gas and Eclectic	Oklahoma Gas and Electric (Holding Co.)	Cincinnati Gas and Electric Company	Arizona Public Service Company	AmerenUE
Depreciation Method		SL Rem Life	SL Rem Life	SL Rem Life	SL Rem Life	SL Rem Life	SL Whole Life (w/ 20Yr.True-up)
Purpose of Study							
Study Data Year		1995	2002	2002	2003	2002	2000
FERC Account							
Account No.	Description						
389.1	Land and Land Rights - Land		Non Depr				
389.2	Land and Land Rights - Land Rights		60-R4				
390	Structures and Improvements		35-S4			39-R1	42-S0
390.1	Structures and Improvements - Leasehold Improvements						
390	Structures and Improvements - Major						
390	Structures and Improvements - Other (Small)						
391	Office Furniture and Equipment		15-SQ	15-SQ			20-L0.5
391	Office Furniture and Equipment - Equipment			3SQ - 10SQ		10-SQUARE	
391	Office Furniture and Equipment - Furniture					20-SQUARE	
391	Office Furniture and Equipment - Hardware (PCs)			3SQ - 10SQ		5-SQUARE	5-L0.5, 5-L3 (PCs)
391	Office Furniture and Equipment - Software			3SQ - 10SQ			
392	Transportation Equipment						10-S0
392.1	Transportation Equipment - Cars		8-L3	6-L3, 7-S2.5			
392.2	Transportation Equipment - Light Trucks		10-R4	9-S3			
392.21	Transportation Equipment - Pickup Trucks		9-S3	8-L3			
392.3	Transportation Equipment - Heavy Trucks		13-R2	13-R2			
392.4	Transportation Equipment - Airplanes and Helicopters						
392.5	Transportation Equipment - Trailers		14-S2	14-S2			
392.6	Transportation Equipment - Other			7-S4, 20-R4			
393	Stores Equipment		25-SQ			20-SQ	22-L0.5
394	Tools, Shop and Garage Equipment		25-SQ	25-SQ		20-SQ	22-L0.5
394.1	Tools, Shop and Garage Equipment - Electric Vehicles						
395	Laboratory Equipment		20-SQ	20-SQ		15-SQ	20-L0.5
396	Power Operated Equipment		17-S2.5	17-S2.5			15-L2
397	Communication Equipment		10-SQ	5SQ - 15SQ		19-S1.5	18-R3
397.1	Communication Equipment - Trans Line						
397.2	Communication Equipment - EMS						
397.3	Communication Equipment - Fiber Optic						
398	Miscellaneous Equipment		20-SQ	15-SQ		20-SQ	18-L0.5
399	Other Tangible Property						

SUMMARY OF SERVICE LIFE RECOMMENDATIONS								
Client		Duquesne Light Company	Metropolitan Edison Company	Bangor Hydro - Electric Company	Pennsylvania Electric Company	Omaha Public Power District	PSI Energy, Inc.	Kentucky Utilities
Depreciation Method		Sl Rem Life	SL Rem Life	(w/ Rem Life True-up)	SL Rem Life	SL Rem Life	SL Rem Life	SL Rem Life
Purpose of Study								
Study Data Year		2001	1999	2002	1999	2007	2002	2007
	FERC Account							
Account No.	Description							
Production Plant								
310 - 316	Steam Production							
310	Steam Production - Land and Land Rights					Non Depr	Non Depr	
310.1	Steam Production - Land and Land Rights - Land							
310.2	Steam Production - Land and Land Rights - Land Rights							
311	Steam Production - Structures and Improvements					100-R2	100-R2.5*	100-S1.5
312	Steam Production - Boiler Plant Equipment					62-S0.5	50-S0.5*	65-R2
312.2	Steam Production - Boiler Plant Equipment - Coal Cars						30-R3	
312.3	Steam Production - Boiler Plant Equipment - Scrubbers							
313	Engines and Engine Driven Generators							
314	Steam Production - Turbogenerator Units					65-R2	65-S1*	55-R2.5
315	Steam Production - Accessory Electric Equipment					50-R3	55-R2*	70-S3
316	Steam Production - Miscellaneous Power Plant Equipment					48-S0.5	40-S0*	70-R1.5
316.1	Steam Production - Miscellaneous Power Plant Equipment - Shop							
316.2	Steam Production - Miscellaneous Power Plant Equipment - Other							
320 - 325	Nuclear Production							
320	Nuclear Production - Land and Land Rights							
320.1	Nuclear Production - Land and Land Rights - Land							
320.2	Nuclear Production - Land and Land Rights - Land Rights							
321	Nuclear Production - Structures and Improvements					100-R2.5		
322	Nuclear Production - Reactor Plant Equipment					40-R2*		
322.1	Nuclear Production - Reactor Plant Equipment - Steam Generators							
323	Nuclear Production - Turbogenerator Units					60-R3*		
324	Nuclear Production - Accessory Electric Equipment					40-S1*		
325	Nuclear Production - Miscellaneous Power Plant Equipment					40-R3*		
330 - 336	Hydraulic Production							
330	Hydraulic Production -Land and Land Rights							Non Depr
330.1	Hydraulic Production -Land and Land Rights - Land							
330.2	Hydraulic Production -Land and Land Rights - Land Rights							100-R4
331	Hydraulic Production - Structures and Improvements						SQ*	90-S2.5
332	Hydraulic Production - Reservoirs, Dams and Waterways						SQ*	100-S2.5
333	Hydraulic Production - Water Wheels, Turbines and Generators						70-R2.5*	80-R3
334	Hydraulic Production - Accessory Electric Equipment						55-R3*	40-L2.5
335	Hydraulic Production - Miscellaneous Power Plant Equipment						50-R2.5*	35-L1
336	Hydraulic Production - Roads, Railroads and Bridges							55-R4
340 - 346	Other Production							
340 - 346	Other Production - Solar							
340	Other Production -Land and Land Rights			Non Depr		Non Depr	Non Depr	Non Depr
340.1	Other Production -Land and Land Rights - Land							
340.2	Other Production -Land and Land Rights - Land Rights							30-R0.5
341	Other Production - Structures and Improvements			120-R1.5*		SQ*	SQ*	40-R2.5
342	Other Production - Fuel Holders, Producers and Accessories			SQ*		SQ*	SQ*	45-R2.5
343	Other Production - Prime Movers			70-R0.5*		60-R2.5	52-R2.5*	35-R1
343.1	Other Production - Prime Movers - Fuel Cells							
343.2	Other Production - Prime Movers - Base Load							
343.3	Other Production - Prime Movers - Peakers							
344	Other Production - Generators			70-L0*		65-R2.5	44-R4*	55-S3
345	Other Production - Accessory Electric Equipment					55-S1.5	45-S1.5*	45-R3
346	Other Production - Miscellaneous Power Plant Equipment			SQ*		SQ*	40-R1.5*	35-R2
Transmission Plant								
350	Land and Land Rights	Non Depr		Non Depr		Non Depr		
350.1	Land and Land Rights - Land		Non Depr		Non Depr		Non Depr	
350.2	Land and Land Rights - Land Rights		80-SQ		80-SQ		75-R4	60-R3
352	Structures and Improvements		55-R3		55-R3	60-R2.5	75-R3	65-S2.5
352.1	Structures and Improvements - Major	65-R2*						
352.2	Structures and Improvements - Small	45-R3						
353	Station Equipment	44-S0.5	46-R2	47-R2	48-R2	43-R1.5	60-R2	30-R2.5
353.2	Station Equipment - Power Supply Company							
353	Station Equipment - 1970 & Prior							
353	Station Equipment - 1971 & Subsequent							
353.1	Station Equipment - Substation on Customer Premises							
353.2	Station Equipment - Portable Property at Substations							
353.3	Station Equipment - Metering Station							
353.4	Station Equipment - Control Equipment (SCADA)			13-L2				
354	Towers and Fixtures	65-R4	65-R3	50-S3	65-R3	70-R2	70-R2.5	70-R4

SUMMARY OF SERVICE LIFE RECOMMENDATIONS

Client		Duquesne Light Company	Metropolitan Edison Company	Bangor Hydro - Electric Company	Pennsylvania Electric Company	Omaha Public Power District	PSI Energy, Inc.	Kentucky Utilities
Depreciation Method		Sl Rem Life	SL Rem Life	(w/ Rem Life True-up)	SL Rem Life	SL Rem Life	SL Rem Life	SL Rem Life
Purpose of Study								
Study Data Year		2001	1999	2002	1999	2007	2002	2007
FERC Account								
Account No.	Description							
354.1	Towers and Fixtures - Clearing Right of Way							
355	Poles and Fixtures	54-R3	55-R2.5	48-R2.5	57-R3	45-R2	56-S0	50-R2
355.1	Poles and Fixtures - Clearing of Right of Way							
355.2	Poles and Fixtures - Wood							
355.3	Poles and Fixtures - Steel							
356	Overhead Conductors and Devices	55-L3	60-R2	45-R3	60-R3	48-R1.5	65-R2	60-R3
356.1	Overhead Conductors and Devices - Clearing of Rights of Way		80-SQ		80-SQ			
357	Underground Conduit	60-S3		60-R4	50-R3	65-R3	65-R3	40-L2.5
358	Underground Conductors and Devices	60-R3		35-R3		30-R3	30-SQ	35-R3
358.1	Underground Conductors and Devices - Submarine							
359	Roads and Trails	55-R4	50-SQ	60-R4	50-SQ			65-R3
Distribution Plant								
360	Land and Land Rights	Non Depr		Non Depr		Non Depr		Non Depr
360.1	Land and Land Rights - Land		Non Depr		Non Depr		Non Depr	
360.2	Land and Land Rights - Land Rights		65-SQ	70-SQ	65-SQ		70-R3	65-R4
361	Structures and Improvements		45-R3	50-R2	45-R3		60-R1.5	60-R2.5
361.1	Structures and Improvements - Major	65-R2*				50-R2		
361.2	Structures and Improvements - Small	45-R3				45-R1.5		
362	Station Equipment		55-R2	43-R2.5	50-R1	50-R0.5	50-R0.5	52-R2
362.1	Station Equipment - Company Stations	55-R1						
362.2	Station Equipment - Customer High Tension	44-R0.5						
362.3	Station Equipment - SCADA			13-L2				
364	Poles, Towers and Fixtures	55-R1	57-R1	45-S1		32-R1.5	43-R0.5	48-S0
364.1	Poles, Towers and Fixtures - Clearing Right of Way							
364.2	Poles, Towers and Fixtures - Towers							
364.4	Poles, Towers and Fixtures - Poles							
364.6	Poles, Towers and Fixtures - Clearing Towers							
364.8	Poles, Towers and Fixtures - Clearing Poles							
364.9	Poles, Towers and Fixtures - Wood							
364.10	Poles, Towers and Fixtures - Steel							
365	Overhead Conductors and Devices	55-R1	53-R0.5	48-S1.5	58-R0.5	34-R1.5	50-R0.5	48-R2
365.1	Sodium Vapor Security Lights							
365.2	Overhead Conductors and Devices - Clearing Rights of Way		65-SQ		65-SQ			
366	Underground Conduit	80-R3	65-R3	60-R3	65-R3	60-R3	65-R3	55-S4
366.1	Underground Conduit - Not encased							
366.2	Underground Conduit - Manholes and Vaults					60-R3		
366.3	Underground Conduit - Encased							
367	Underground Conductors and Devices	49-R1	35-R3	47-R2.5	35-R3	32-R2	55-R2	44-S0.5
367.1	Underground Conductors and Devices - Clearing Right of Way							
368	Line Transformers		37-S0.5	39-R2	32-S0	33-R2.5	35-R1	40-R2
368.1	Line Transformers - Pole Top	44-S0						
368.2	Line Transformers - Pad Mounted	46-R1						
368.3	Line Transformers - Non-Network Housing							
368.4	Line Transformers - Network	55-R2						
368.5	Line Transformers - Underground Residential Distribution	38-R1.5						
369	Services	60-R3		45-R4		45-R3		43-R1.5
369.1	Services - Overhead		40-R0.5		39-O1		35-R1	
369.2	Services - Underground		38-R2		36-R3		40-R1.5	
370	Meters	30-R2.5	24-O1	33-R2.5	26-S0	28-R4	32-R2	40-R1.5
370.2	Meters - AMR and Electronic	10-S3		12-S2				
371	Installations on Customer Premises		10SQ - 25SQ		10SQ - 25-SQ	16-R1	14-L0	20-R0.5
371.2	Installations on Customer Premises - Area Lighting		20-O1		20-O1			
372	Leased Property on Customer Premises				30-SQ			
373	Street Lighting and Signal Systems	23-S0	31-R0.5		22-O1	29-R1.5	24-R1	33-R1
373.1	Street Lighting and Signal Systems - Clearing							
373.2	Street Lighting and Signal Systems - M.V.			28-R3				
373.3	Street Lighting and Signal Systems - H.P.S.			20-S2				
General and Intangible Plant								
301	Organization		Non Depr	Intangible	Non Depr			
302	Franchises and Consents		Non Depr	Intangible	Non Depr			
303	Intangible Plant		7SQ - 10SQ	Intangible				
303.1	Intangible Plant - Software				7SQ, 10SQ			
303.2	Intangible Plant - Fiber Optic							
389	Land and Land Rights	Non Depr		Non Depr		Non Depr	Non Depr	Non Depr

SUMMARY OF SERVICE LIFE RECOMMENDATIONS

Client		**Duquesne Light Company**	**Metropolitan Edison Company**	**Bangor Hydro - Electric Company**	**Pennsylvania Electric Company**	**Omaha Public Power District**	**PSI Energy, Inc.**	**Kentucky Utilities**
Depreciation Method		Sl Rem Life	SL Rem Life	(w/ Rem Life True-up)	SL Rem Life	SL Rem Life	SL Rem Life	SL Rem Life
Purpose of Study								
Study Data Year		2001	1999	2002	1999	2007	2002	2007
FERC Account								
Account No.	Description							
389.1	Land and Land Rights - Land		Non Depr		Non Depr			
389.2	Land and Land Rights - Land Rights		50-SQ		50-SQ			
390	Structures and Improvements							60-S0
390.1	Structures and Improvements - Leasehold Improvements							30-R1
390	Structures and Improvements - Major	65-R2*	0-S0*, SQ* (Yard	120-R1*	S0*, SQ (Impro	SQ*	1*, SQ* (Amorti	
390	Structures and Improvements - Other (Small)	45-R3	R1, 25-R1 (improv	40-R1, Various	1, 25-R1 (Impr	33-S1	40-R3	
391	Office Furniture and Equipment						20-SQ	20-SQ
391	Office Furniture and Equipment - Equipment	7-SQ		10-SQ	10-SQ			5-SQ
391	Office Furniture and Equipment - Furniture	20-SQ	20-SQ	20-SQ	20-SQ			
391	Office Furniture and Equipment - Hardware (PCs)	5-SQ	10SQ, 3SQ (PCs	5-SQ	5SQ, 3-SQ(PCs	6-R4	5-SQ	4-SQ
391	Office Furniture and Equipment - Software							
392	Transportation Equipment					13-R2		
392.1	Transportation Equipment - Cars	6.5-S2.5		5-L1.5				
392.2	Transportation Equipment - Light Trucks				7-L3			
392.21	Transportation Equipment - Pickup Trucks							
392.3	Transportation Equipment - Heavy Trucks		10-L3		10-S3			
392.4	Transportation Equipment - Airplanes and Helicopters							
392.5	Transportation Equipment - Trailers		25-S1		26-S1		26-L1.5	
392.6	Transportation Equipment - Other	12-S2						
393	Stores Equipment	30-SQ	20SQ	20-SQ	20-SQ		20-SQ	25-SQ
394	Tools, Shop and Garage Equipment	25-SQ			25-SQ		25-SQ	25-SQ
394.1	Tools, Shop and Garage Equipment - Electric Vehicles							
395	Laboratory Equipment	20-SQ			20-SQ		20-SQ	15-SQ
396	Power Operated Equipment	21-S0	15-L3	10.5-R1.5	21-S0.5	18-L0.5	20-S0.5	17-R5
397	Communication Equipment	15-SQ	15-R1	13-L2	15-R1	20-R1.5	19-L2	15-SQ
397.1	Communication Equipment - Trans Line							
397.2	Communication Equipment - EMS		SQ*		SQ*			
397.3	Communication Equipment - Fiber Optic							
398	Miscellaneous Equipment	20-SQ	20-SQ	20-SQ	20-SQ		15-SQ	10-SQ
399	Other Tangible Property							

SUMMARY OF SERVICE LIFE RECOMMENDATIONS								
Client		El Paso Electric Company	Duke Power Company	Nevada Power Company	Chugach Electric Association, Inc	Puget Sound Energy	Idaho Power Company	Louisville Gas & Electric
Depreciation Method		SL Rem Life	Sl Rem Life	SL Rem Life	SL Rem Life	S.l. Rem. Life	SL Rem. Life	SL Rem. Life
Purpose of Study								
Study Data Year		2002	2003	2006	2002	2007	2007	2007
FERC Account								
Account No.	Description							
Production Plant								
310 - 316	Steam Production							
310	Steam Production - Land and Land Rights	Non Depr						
310.1	Steam Production - Land and Land Rights - Land		Non Depr	Non Depr				
310.2	Steam Production - Land and Land Rights - Land Rights		75-R4*	SQ*			75-R4	
311	Steam Production - Structures and Improvements	100-S1.5*	100-S0.5*	125-R2*	65-R1.5*	125-R2	100-S1	100-S1.5
312	Steam Production - Boiler Plant Equipment	80-S2*	45-S3*	65-R1.5*	65-R2.5*	65-R1.5	70-R1.5	45-R1.5
312.2	Steam Production - Boiler Plant Equipment - Coal Cars						25-R3	
312.3	Steam Production - Boiler Plant Equipment - Scrubbers						60-R3	
313	Engines and Engine Driven Generators	40-R2.5*						
314	Steam Production - Turbogenerator Units	75-R3	55-S2.5*	100-R1	65-R3*	70-R2	50-S0.5	50-S1.5
315	Steam Production - Accessory Electric Equipment	65-S1	50-S1.5*	75-S1.5*	30-R3*	70-S2	65-S1.5	50-S2
316	Steam Production - Miscellaneous Power Plant Equipment	55-R2	60-R1.5*	35-S0*	35-R2.5*	45-R0.5	50-R0.5	40-S2
316.1	Steam Production - Miscellaneous Power Plant Equipment - Shop							
316.2	Steam Production - Miscellaneous Power Plant Equipment - Other							
320 - 325	Nuclear Production							
320	Nuclear Production - Land and Land Rights							
320.1	Nuclear Production - Land and Land Rights - Land		Non Depr					
320.2	Nuclear Production - Land and Land Rights - Land Rights		75-R4*					
321	Nuclear Production - Structures and Improvements		100-S0.5*					
322	Nuclear Production - Reactor Plant Equipment		55-R1.5*					
322.1	Nuclear Production - Reactor Plant Equipment - Steam Generators							
323	Nuclear Production - Turbogenerator Units		50-R1*					
324	Nuclear Production - Accessory Electric Equipment		50-S1.5*					
325	Nuclear Production - Miscellaneous Power Plant Equipment		60-R1.5*					
330 - 336	Hydraulic Production							
330	Hydraulic Production -Land and Land Rights							
330.1	Hydraulic Production -Land and Land Rights - Land		Non Depr					
330.2	Hydraulic Production -Land and Land Rights - Land Rights		90-R4*					
331	Hydraulic Production - Structures and Improvements		90-R3*		90-S2*	100-S1.5	100-R2.5	100-S2.5
332	Hydraulic Production - Reservoirs, Dams and Waterways		110-L2.5*		90-S1.5*	100-S1.5	90-S4	100-S2.5
333	Hydraulic Production - Water Wheels, Turbines and Generators		75-S0.5*		45-S3.5*	70-R1.5	80-R3	100-S2.5
334	Hydraulic Production - Accessory Electric Equipment		50-L0.5*		40-S4*	65-R1	50-R1.5	80-S4
335	Hydraulic Production - Miscellaneous Power Plant Equipment		60-R1.5*		40-R4*	35-S1.5	90-R2	80-S3
336	Hydraulic Production - Roads, Railroads and Bridges		65-R2.5*		40-S3*	70-R5	75-R3	80-S4
340 - 346	Other Production							
340 - 346	Other Production - Solar							
340	Other Production -Land and Land Rights	Non Depr			Non Depr			
340.1	Other Production -Land and Land Rights - Land		Non Depr					
340.2	Other Production -Land and Land Rights - Land Rights			SQ*				
341	Other Production - Structures and Improvements	SQ	SQ*	SQ*	65-R1.5*	40-R5	SQ	55-R3
342	Other Production - Fuel Holders, Producers and Accessories	SQ	SQ*	SQ*	28-S3*	40-R5	SQ	50-R3
343	Other Production - Prime Movers		SQ*	SQ*			SQ	30-R2
343.1	Other Production - Prime Movers - Fuel Cells				5.5-S4			
343.2	Other Production - Prime Movers - Base Load				12-L1*			
343.3	Other Production - Prime Movers - Peakers				30-R3*			
344	Other Production - Generators	SQ	SQ*	35-S2*	65-R3*	40-R5	SQ	60-S3
345	Other Production - Accessory Electric Equipment	SQ	SQ*	45-S0*	30-R3*	40-R5	SQ	35-S1.5
346	Other Production - Miscellaneous Power Plant Equipment	SQ	SQ*	SQ*	35-R2.5*	40-R5	SQ	50-S3
Transmission Plant								
350	Land and Land Rights				Non Depr			
350.1	Land and Land Rights - Land		Non Depr	Non Depr				
350.2	Land and Land Rights - Land Rights	70-R4	65-R3	60-R5			65-R3	50-R3
352	Structures and Improvements		43-R3	50-R3	50-R3	55-R3	60-R3	60-R2.5
352.1	Structures and Improvements - Major	55-S2*						
352.2	Structures and Improvements - Small	55-S2						
353	Station Equipment	45-R3	39-R2.5	50-R2	40-S2.5	45-R1	45-R1	55-R2.5
353.2	Station Equipment - Power Supply Company							
353	Station Equipment - 1970 & Prior							
353	Station Equipment - 1971 & Subsequent							
353.1	Station Equipment - Substation on Customer Premises							
353.2	Station Equipment - Portable Property at Substations							
353.3	Station Equipment - Metering Station							
353.4	Station Equipment - Control Equipment (SCADA)				10-SQ			
354	Towers and Fixtures	65-R4	48-R4	60-R4	65-R4	65-R4	65-S3	65-R3

SUMMARY OF SERVICE LIFE RECOMMENDATIONS

Client		El Paso Electric Company	Duke Power Company	Nevada Power Company	Chugach Electric Association, Inc	Puget Sound Energy	Idaho Power Company	Louisville Gas & Electric
Depreciation Method		SL Rem Life	SI Rem Life	SL Rem Life	SL Rem Life	S.I. Rem. Life	SL Rem. Life	SL Rem. Life
Purpose of Study								
Study Data Year		2002	2003	2006	2002	2007	2007	2007
FERC Account								
Account No.	Description							
354.1	Towers and Fixtures - Clearing Right of Way							
355	Poles and Fixtures	40-R2.5	40-R3	45-R1.5	38-R2.5	45-R2	55-R2	50-R2
355.1	Poles and Fixtures - Clearing of Right of Way							
355.2	Poles and Fixtures - Wood							
355.3	Poles and Fixtures - Steel							
356	Overhead Conductors and Devices	50-R5	40-R4	50-R1.5	40-R2.5	50-R3	65-R1.5	50-R2
356.1	Overhead Conductors and Devices - Clearing of Rights of Way							
357	Underground Conduit		50-R4	50-R2	50-R4			50-R3
358	Underground Conductors and Devices		40-R3	35-R3	30-S3	50-R3		30-R3
358.1	Underground Conductors and Devices - Submarine				20-S3 (So.), 35-R3 (No.)			
359	Roads and Trails	40-S1.5		60-R5	50-R3	60-R4	65-R3	
Distribution Plant								
360	Land and Land Rights				Non Depr			
360.1	Land and Land Rights - Land		Non Depr	Non Depr				
360.2	Land and Land Rights - Land Rights	70-R4	65-R3	65-R4				
361	Structures and Improvements	55-S2	41-R4	50-R3	50-R3	55-R3	65-R2.5	60-R3
361.1	Structures and Improvements - Major							
361.2	Structures and Improvements - Small							
362	Station Equipment	45-R3	35-R1.5	50-R1.5	29-R3	45-R1.5	50-R0.5	55-R1.5
362.1	Station Equipment - Company Stations							
362.2	Station Equipment - Customer High Tension							
362.3	Station Equipment - SCADA				10-SQ			
364	Poles, Towers and Fixtures	39-R3	35-R2.5	50-R1.5	32-R3	45-R2	44-R1.5	50-R2.5
364.1	Poles, Towers and Fixtures - Clearing Right of Way							
364.2	Poles, Towers and Fixtures - Towers							
364.4	Poles, Towers and Fixtures - Poles							
364.6	Poles, Towers and Fixtures - Clearing Towers							
364.8	Poles, Towers and Fixtures - Clearing Poles							
364.9	Poles, Towers and Fixtures - Wood							
364.10	Poles, Towers and Fixtures - Steel							
365	Overhead Conductors and Devices	40-R2.5	32-R1	50-R1	32-R2.5	40-R2.5	47-R0.5	45-R1.5
365.1	Sodium Vapor Security Lights							
365.2	Overhead Conductors and Devices - Clearing Rights of Way							
366	Underground Conduit	50-R3	42-R3	50-R3	50-R3	50-R4	60-R2	70-R4
366.1	Underground Conduit - Not encased							
366.2	Underground Conduit - Manholes and Vaults							
366.3	Underground Conduit - Encased							
367	Underground Conductors and Devices	33-R2.5	33-R4	35-S4	R4, 15-S3 (Cabl	35-R2.5	50-S0.5	50-R2
367.1	Underground Conductors and Devices - Clearing Right of Way							
368	Line Transformers	45-R3	32-R1.5	38-R2.5	29-R3	40-R2	37-R1	45-R1.5
368.1	Line Transformers - Pole Top							
368.2	Line Transformers - Pad Mounted							
368.3	Line Transformers - Non-Network Housing							
368.4	Line Transformers - Network							
368.5	Line Transformers - Underground Residential Distribution							
369	Services	50-S3	30-R1.5	40-R4	40-R3	45-R3	**35-R2.5**	
369.1	Services - Overhead							45-S1.5
369.2	Services - Underground							45-R1.5
370	Meters	28-R2.5	25-O1	35-R1	18-R2.5	35-R2.5	**20-O1**	30-R2
370.2	Meters - AMR and Electronic						**15-S3**	
371	Installations on Customer Premises	27-R1.5	24-O1		20-R2		**10-R2**	
371.2	Installations on Customer Premises - Area Lighting						**15-R2**	
372	Leased Property on Customer Premises			25-R1				
373	Street Lighting and Signal Systems	45-R2.5	30-R2.5	25-R1	32-R3	35-R2.5	**25-R1.5**	35-R1.5
373.1	Street Lighting and Signal Systems - Clearing							
373.2	Street Lighting and Signal Systems - M.V.							
373.3	Street Lighting and Signal Systems - H.P.S.							
General and Intangible Plant								
301	Organization							
302	Franchises and Consents							
303	Intangible Plant			10-SQ	Non Depr			
303.1	Intangible Plant - Software							
303.2	Intangible Plant - Fiber Optic							
389	Land and Land Rights	Non Depr			Non Depr			

SUMMARY OF SERVICE LIFE RECOMMENDATIONS

Client		El Paso Electric Company	Duke Power Company	Nevada Power Company	Chugach Electric Association, Inc	Puget Sound Energy	Idaho Power Company	Louisville Gas & Electric
Depreciation Method		SL Rem Life	SI Rem Life	SL Rem Life	SL Rem Life	S.I. Rem. Life	SL Rem. Life	SL Rem. Life
Purpose of Study								
Study Data Year		2002	2003	2006	2002	2007	2007	2007
FERC Account								
Account No.	Description							
389.1	Land and Land Rights - Land			Non Depr				
389.2	Land and Land Rights - Land Rights		40-SQ	50-SQ				
390	Structures and Improvements		40-R2	45-R2	65-R4	35-R4	50-L2	
390.1	Structures and Improvements - Leasehold Improvements				SQ*		30-S3	
390	Structures and Improvements - Major	90-S1.5*					100-S1.5	
390	Structures and Improvements - Other (Small)	40-R2.5			45-S3, 25-S3 (MW Bldgs.)			
391	Office Furniture and Equipment	, SQ* (Four Co	10-SQ	20-SQ	10-SQ		20-SQ	
391	Office Furniture and Equipment - Equipment						7-SQ	
391	Office Furniture and Equipment - Furniture					20-SQ		
391	Office Furniture and Equipment - Hardware (PCs)		8-SQ	5-SQ	5-SQ	5-SQ	5-SQ	
391	Office Furniture and Equipment - Software							
392	Transportation Equipment			Various	7-R2.5	10-SQ		
392.1	Transportation Equipment - Cars		5-R3				10-L2.5	
392.2	Transportation Equipment - Light Trucks		6-R3				10-L2.5	
392.21	Transportation Equipment - Pickup Trucks		7-R3, 7-R4 (Power Equipped)					
392.3	Transportation Equipment - Heavy Trucks		10-R2, 10-R2.5 (Power Equipped)				19-S2	
392.4	Transportation Equipment - Airplanes and Helicopters						8-S2.5	
392.5	Transportation Equipment - Trailers		17-L1				30-S1.5	30-S4
392.6	Transportation Equipment - Other		12-R3					
393	Stores Equipment	, SQ* (Four Co	10-SQ	20-SQ	20-SQ	20-SQ	25-SQ	
394	Tools, Shop and Garage Equipment	25-SQ	10-SQ	25-SQ	20-SQ		20-SQ	25-SQ
394.1	Tools, Shop and Garage Equipment - Electric Vehicles							
395	Laboratory Equipment	15-SQ	10-SQ	15-SQ	20-SQ	20-SQ	20-SQ	15-SQ
396	Power Operated Equipment	19-R-2.5* (Fou	10-	Various	12-S2	15-SQ	16-SQ	30-R1.5
397	Communication Equipment	, SQ* (Four Co	10-SQ	15-SQ	10-SQ	15-SQ	15-SQ	
397.1	Communication Equipment - Trans Line							
397.2	Communication Equipment - EMS							
397.3	Communication Equipment - Fiber Optic						10-SQ	
398	Miscellaneous Equipment	15-SQ	10-SQ	15-SQ	10-SQ, Non Dep	15-SQ	15-SQ	
399	Other Tangible Property							

SUMMARY OF NET SALVAGE RECOMMENDATIONS

GF Order	Account No.	Description	Jackson Energy Cooperative	Alliant	Dominion-Virginia Power	Bonneville Power Administration	Sierra Pacific Power Company
	Client		Jackson Energy Cooperative	Alliant	Dominion-Virginia Power	Bonneville Power Administration	Sierra Pacific Power Company
	Depreciation Method		SL Rem Life	SL Rem Life	SL Rem Life	SL Rem Life	SL Whole Life
	Purpose of Study						
	Study Data Year		1999	2000	2001	1998	2006
	FERC Account						
GF Order	Account No.	Description					
	Production Plant						
1	310 - 316	Steam Production					
	310	Steam Production - Land and Land Rights					
	310.1	Steam Production - Land and Land Rights - Land					
	310.2	Steam Production - Land and Land Rights - Land Rights					
	311	Steam Production - Structures and Improvements		(20)			(50)
23	312	Steam Production - Boiler Plant Equipment		(10)			(50)
	312.2	Steam Production - Boiler Plant Equipment - Coal Cars					
	312.3	Steam Production - Boiler Plant Equipment - Scrubbers					
	313	Engines and Engine Driven Generators					
	314	Steam Production - Turbogenerator Units		(40)			(50)
	315	Steam Production - Accessory Electric Equipment		0			(50)
	316	Steam Production - Miscellaneous Power Plant Equipment		0			(50)
	316.1	Steam Production - Miscellaneous Power Plant Equipment - Shop					
	316.2	Steam Production - Miscellaneous Power Plant Equipment - Other					
	320 - 325	Nuclear Production					
	320	Nuclear Production - Land and Land Rights					
	320.1	Nuclear Production - Land and Land Rights - Land					
	320.2	Nuclear Production - Land and Land Rights - Land Rights					
	321	Nuclear Production - Structures and Improvements					
	322	Nuclear Production - Reactor Plant Equipment					
	322.1	Nuclear Production - Reactor Plant Equipment - Steam Generators					
	323	Nuclear Production - Turbogenerator Units					
	324	Nuclear Production - Accessory Electric Equipment					
	325	Nuclear Production - Miscellaneous Power Plant Equipment					
24	330 - 336	Hydraulic Production					
2	330	Hydraulic Production -Land and Land Rights					
	330.1	Hydraulic Production -Land and Land Rights - Land					
	330.2	Hydraulic Production -Land and Land Rights - Land Rights					
25	331	Hydraulic Production - Structures and Improvements					(2)
17	332	Hydraulic Production - Reservoirs, Dams and Waterways					(2)
27	333	Hydraulic Production - Water Wheels, Turbines and Generators					(2)
29	334	Hydraulic Production - Accessory Electric Equipment					(2)
15	335	Hydraulic Production - Miscellaneous Power Plant Equipment					(2)
16	336	Hydraulic Production - Roads, Railroads and Bridges					(2)
3	340 - 346	Other Production					
	340 - 346	Other Production - Solar					
	340	Other Production -Land and Land Rights					
	340.1	Other Production -Land and Land Rights - Land					
	340.2	Other Production -Land and Land Rights - Land Rights					
6	341	Other Production - Structures and Improvements		0			(10)
13	342	Other Production - Fuel Holders, Producers and Accessories		(5)			(10)
7	343	Other Production - Prime Movers		0			(10)
	343.1	Other Production - Prime Movers - Fuel Cells					
	343.2	Other Production - Prime Movers - Base Load					
	343.3	Other Production - Prime Movers - Peakers					
	344	Other Production - Generators		0			(10)
12	345	Other Production - Accessory Electric Equipment		0			(10)
	346	Other Production - Miscellaneous Power Plant Equipment		0			(10)
1							
2							
3	**Transmission Plant**						
4	350	Land and Land Rights		Non Depr		Non Depr	
	350.1	Land and Land Rights - Land			Non Depr		
	350.2	Land and Land Rights - Land Rights			0	0	
40	352	Structures and Improvements		0	(5)	(5)	(5)
	352.1	Structures and Improvements - Major					
	352.2	Structures and Improvements - Small					
1700	353	Station Equipment		(5)	(10)		(10)
	353.2	Station Equipment - Power Supply Company			(5)		
	353	Station Equipment - 1970 & Prior				(10)	
	353	Station Equipment - 1971 & Subsequent				(10)	
	353.1	Station Equipment - Substation on Customer Premises				(10)	
	353.2	Station Equipment - Portable Property at Substations				(10)	
	353.3	Station Equipment - Metering Station				(10)	

	SUMMARY OF NET SALVAGE RECOMMENDATIONS						
	Client		**Jackson Energy Cooperative**	**Alliant**	**Dominion-Virginia Power**	**Bonneville Power Administration**	**Sierra Pacific Power Company**
	353.4	Station Equipment - Control Equipment				(10)	
22	354	Towers and Fixtures		(50)	(50)	(25)	(10)
	354.1	Towers and Fixtures - Clearing Right of Way			0		
31	355	Poles and Fixtures		(40)	(30)	(70)	(30)
	355.1	Poles and Fixtures - Clearing Right of Way			0		
	355.2	Poles and Fixtures - Wood					
	355.3	Poles and Fixtures - Steel					
33	356	Overhead Conductors and Devices		(10)	(20)	(25)	(25)
	356.1	Overhead Conductors and Devices - Clearing of Rights of Way					
34	357	Underground Conduit			0		(10)
35	358	Underground Conductors and Devices		0	(5)	(10)	(15)
	358.1	Underground Conductors and Devices - Submarine					
39	359	Roads and Trails			0	0	0
48							
600							
1600	**Distribution Plant**						
1800	360	Land and Land Rights		Non Depr			
	360.1	Land and Land Rights - Land			Non Depr		
	360.2	Land and Land Rights - Land Rights			0		
1900	361	Structures and Improvements		0	(5)		(5)
	361.1	Structures and Improvements - Major					
	361.2	Structures and Improvements - Small					
2000	362	Station Equipment		(5)	(10)		(10)
	362.1	Station Equipment - Company Stations					
	362.2	Station Equipment - Customer High Tension					
	362.3	Station Equipment - SCADA					
5	364	Poles, Towers and Fixtures	(45)	(75)	(40)		(15)
	364.1	Poles, Towers and Fixtures - Clearing Right of Way			0		
	364.2	Poles, Towers and Fixtures - Towers					
	364.4	Poles, Towers and Fixtures - Poles					
	364.6	Poles, Towers and Fixtures - Clearing Towers					
	364.8	Poles, Towers and Fixtures - Clearing Poles					
	364.9	Poles, Towers and Fixtures - Wood					
	364.10	Poles, Towers and Fixtures - Steel					
6	365	Overhead Conductors and Devices	(30)	(25)	(20)		(50)
	365.1	Sodium Vapor Security Lights		(5)			
	365.2	Overhead Conductors and Devices - Clearing Rights of Way					
7	366	Underground Conduit	0	40			(10)
	366.1	Underground Conduit - Not encased			0		
	366.2	Underground Conduit - Manholes and Vaults			0		
	366.3	Underground Conduit - Encased			0		
9	367	Underground Conductors and Devices	(10)	(15)	(10)		(40)
	367.1	Underground Conductors and Devices - Clearing Right of Way			0		
44	368	Line Transformers	0	(5)	(5)		(15)
	368.1	Line Transformers - Pole Top					(5)
	368.2	Line Transformers - Pad Mounted					(5)
	368.3	Line Transformers - Non-Network Housing					
	368.4	Line Transformers - Network					
	368.5	Line Transformers - Underground Residential Distribution					
46	369	Services	(75)	(40)			(60)
	369.1	Services - Overhead			(30)		
	369.2	Services - Underground			(15)		
100	370	Meters	0	0	0		0
	370.2	Meters - AMR and Electronic					
11	371	Installations on Customer Premises	(15)	(5)	0		(40)
	371.2	Installations on Customer Premises - Area Lighting					
	372	Leased Property on Customer Premises					
12	373	Street Lighting and Signal Systems	(50)	(20)	(20)		(20)
	373.1	Street Lighting and Signal Systems - Clearing			0		
	373.2	Street Lighting and Signal Systems - M.V.					
13	373.3	Street Lighting and Signal Systems - H.P.S.					
14							
15	**General and Intangible Plant**						
	301	Organization					
	302	Franchises and Consents		Non Depr	0		
16	303	Intangible Plant		Non Depr	Non Depr	0	
	303.1	Intangible Plant - Software					
	303.2	Intangible Plant - Fiber Optic					
17	389	Land and Land Rights	Non Depr	Non Depr			
	389.1	Land and Land Rights - Land			Non Depr		
	389.2	Land and Land Rights - Land Rights			0	0	
18	390	Structures and Improvements	0 - (25)	(5)		(5)	(5)
	390.1	Structures and Improvements - Leasehold Improvements		0			
	390	Structures and Improvements - Major			(5)		

SUMMARY OF NET SALVAGE RECOMMENDATIONS

	Client		Jackson Energy Cooperative	Alliant	Dominion-Virginia Power	Bonneville Power Administration	Sierra Pacific Power Company
	390	Structures and Improvements - Other			(5)		
	391	Office Furniture and Equipment			0		0
19	391	Office Furniture and Equipment - Equipment	0	0			
20	391	Office Furniture and Equipment - Furniture	0	0		20-SQ	
45	391	Office Furniture and Equipment - Hardware (PCs)	0	0	0	5-SQ	0
47	391	Office Furniture and Equipment - Software	0			5-SQ	
	392	Transportation Equipment			15	0	10
200	392.1	Transportation Equipment - Cars	20	15			
300	392.2	Transportation Equipment - Light Trucks	20	20			
	392.21	Transportation Equipment - Pickup Trucks					
400	392.3	Transportation Equipment - Heavy Trucks	20				
	392.4	Transportation Equipment - Airplanes and Helicopters				50	
	392.5	Transportation Equipment - Trailers					
	392.6	Transportation Equipment - Other					
23	393	Stores Equipment	0	0	0	0	0
24	394	Tools, Shop and Garage Equipment	0	0	0	0	0
	394.1	Tools, Shop and Garage Equipment - Electric Vehicles			0		
500	395	Laboratory Equipment	0	0	0	0	0
700	396	Power Operated Equipment	0	20	10	0	10
800	397	Communication Equipment	0	0	0	0	0
	397.1	Communication Equipment - Trans Line				0	
	397.2	Communication Equipment - EMS					
	397.3	Communication Equipment - Fiber Optic					
900	398	Miscellaneous Equipment	0	0	0	0	0
25	399	Other Tangible Property					

	SUMMARY OF NET SALVAGE RECOMMENDATIONS						
	Client		Reliant Energy	PPL Electric Corporation	Owen Electric Cooperative	Oklahoma Gas and Electric	Oklahoma Gas and Electric (Holding Co.)
	Depreciation Method		SL Rem Life	SL Rem Life	SL Rem Life	SL Rem Life	SL Rem Life
	Purpose of Study						
	Study Data Year		2002	2007	1995	2002	2002
	FERC Account						
GF Order	Account No.	Description					
	Production Plant						
1	310 - 316	Steam Production					
	310	Steam Production - Land and Land Rights					
	310.1	Steam Production - Land and Land Rights - Land				Non Depr	
	310.2	Steam Production - Land and Land Rights - Land Rights				0	
	311	Steam Production - Structures and Improvements				(15)	
23	312	Steam Production - Boiler Plant Equipment				(10)	
	312.2	Steam Production - Boiler Plant Equipment - Coal Cars					
	312.3	Steam Production - Boiler Plant Equipment - Scrubbers					
	313	Engines and Engine Driven Generators					
	314	Steam Production - Turbogenerator Units				(10)	
	315	Steam Production - Accessory Electric Equipment				0	
	316	Steam Production - Miscellaneous Power Plant Equipment				(5)	
	316.1	Steam Production - Miscellaneous Power Plant Equipment - Shop					
	316.2	Steam Production - Miscellaneous Power Plant Equipment - Other					
	320 - 325	Nuclear Production					
	320	Nuclear Production - Land and Land Rights					
	320.1	Nuclear Production - Land and Land Rights - Land					
	320.2	Nuclear Production - Land and Land Rights - Land Rights					
	321	Nuclear Production - Structures and Improvements					
	322	Nuclear Production - Reactor Plant Equipment					
	322.1	Nuclear Production - Reactor Plant Equipment - Steam Generators					
	323	Nuclear Production - Turbogenerator Units					
	324	Nuclear Production - Accessory Electric Equipment					
	325	Nuclear Production - Miscellaneous Power Plant Equipment					
24	330 - 336	Hydraulic Production					
2	330	Hydraulic Production -Land and Land Rights					
	330.1	Hydraulic Production -Land and Land Rights - Land					
	330.2	Hydraulic Production -Land and Land Rights - Land Rights					
25	331	Hydraulic Production - Structures and Improvements					
17	332	Hydraulic Production - Reservoirs, Dams and Waterways					
27	333	Hydraulic Production - Water Wheels, Turbines and Generators					
29	334	Hydraulic Production - Accessory Electric Equipment					
15	335	Hydraulic Production - Miscellaneous Power Plant Equipment					
16	336	Hydraulic Production - Roads, Railroads and Bridges					
3	340 - 346	Other Production					
	340 - 346	Other Production - Solar					
	340	Other Production -Land and Land Rights					
	340.1	Other Production -Land and Land Rights - Land					
	340.2	Other Production -Land and Land Rights - Land Rights					
6	341	Other Production - Structures and Improvements				0	
13	342	Other Production - Fuel Holders, Producers and Accessories				0 - (7)	
7	343	Other Production - Prime Movers				0 - (6)	
	343.1	Other Production - Prime Movers - Fuel Cells					
	343.2	Other Production - Prime Movers - Base Load					
	343.3	Other Production - Prime Movers - Peakers					
	344	Other Production - Generators				0	
12	345	Other Production - Accessory Electric Equipment				0 - (6)	
	346	Other Production - Miscellaneous Power Plant Equipment				0 - (6)	
1							
2							
3	**Transmission Plant**						
4	350	Land and Land Rights					
	350.1	Land and Land Rights - Land		Non Depr		Non Depr	
	350.2	Land and Land Rights - Land Rights	0	70-R4		0	
40	352	Structures and Improvements	(45)	55-R4		(5)	
	352.1	Structures and Improvements - Major					
	352.2	Structures and Improvements - Small					
1700	353	Station Equipment	5	45-R1		(5)	
	353.2	Station Equipment - Power Supply Company					
	353	Station Equipment - 1970 & Prior					
	353	Station Equipment - 1971 & Subsequent					
	353.1	Station Equipment - Substation on Customer Premises					
	353.2	Station Equipment - Portable Property at Substations					
	353.3	Station Equipment - Metering Station					

	SUMMARY OF NET SALVAGE RECOMMENDATIONS						
	Client		Reliant Energy	PPL Electric Corporation	Owen Electric Cooperative	Oklahoma Gas and Electric	Oklahoma Gas and Electric (Holding Co.)
	353.4	Station Equipment - Control Equipment					
22	354	Towers and Fixtures	0	60-R3		(20)	
	354.1	Towers and Fixtures - Clearing Right of Way		70-R4			
31	355	Poles and Fixtures	(65)	50-R1.5		(50)	
	355.1	Poles and Fixtures - Clearing Right of Way		70-R4			
	355.2	Poles and Fixtures - Wood					
	355.3	Poles and Fixtures - Steel					
33	356	Overhead Conductors and Devices	(80)	55-R3		(30)	
	356.1	Overhead Conductors and Devices - Clearing of Rights of Way					
34	357	Underground Conduit	0	50-R4			
35	358	Underground Conductors and Devices	0	35-R3		0	
	358.1	Underground Conductors and Devices - Submarine					
39	359	Roads and Trails	0	70-R4			
48							
600							
1600	**Distribution Plant**						
1800	360	Land and Land Rights					
	360.1	Land and Land Rights - Land		Non Depr		Non Depr	
	360.2	Land and Land Rights - Land Rights	0	60-R3		0	
1900	361	Structures and Improvements	(50)	60-R2.5		(10)	
	361.1	Structures and Improvements - Major					
	361.2	Structures and Improvements - Small					
2000	362	Station Equipment	5	48-R2		(10)	
	362.1	Station Equipment - Company Stations					
	362.2	Station Equipment - Customer High Tension					
	362.3	Station Equipment - SCADA					
5	364	Poles, Towers and Fixtures	(45)		(95)	(35)	
	364.1	Poles, Towers and Fixtures - Clearing Right of Way					
	364.2	Poles, Towers and Fixtures - Towers		60-R3			
	364.4	Poles, Towers and Fixtures - Poles		40-R0.5			
	364.6	Poles, Towers and Fixtures - Clearing Towers		50-S3			
	364.8	Poles, Towers and Fixtures - Clearing Poles		60-R3			
	364.9	Poles, Towers and Fixtures - Wood					
	364.10	Poles, Towers and Fixtures - Steel					
6	365	Overhead Conductors and Devices	(25)	44-R1	(75)	(25)	
	365.1	Sodium Vapor Security Lights					
	365.2	Overhead Conductors and Devices - Clearing Rights of Way					
7	366	Underground Conduit	(30)	50-S2		(15)	
	366.1	Underground Conduit - Not encased					
	366.2	Underground Conduit - Manholes and Vaults					
	366.3	Underground Conduit - Encased					
9	367	Underground Conductors and Devices	(15)	42-S1.5	(20)	(20)	
	367.1	Underground Conductors and Devices - Clearing Right of Way					
44	368	Line Transformers	0		0	(10)	
	368.1	Line Transformers - Pole Top		34-SQ			
	368.2	Line Transformers - Pad Mounted		48-SQ			
	368.3	Line Transformers - Non-Network Housing		35-SQ			
	368.4	Line Transformers - Network					
	368.5	Line Transformers - Underground Residential Distribution					
46	369	Services	(45)	37-R2	(85)	(20)	
	369.1	Services - Overhead					
	369.2	Services - Underground					
100	370	Meters	0	28-SQ	0	(15)	
	370.2	Meters - AMR and Electronic		15-SQ			
11	371	Installations on Customer Premises		30-R3	(35)		
	371.2	Installations on Customer Premises - Area Lighting		19-L0.5			
	372	Leased Property on Customer Premises					
12	373	Street Lighting and Signal Systems	(60)	30-S0.5	(35)	(20)	
	373.1	Street Lighting and Signal Systems - Clearing					
	373.2	Street Lighting and Signal Systems - M.V.					
13	373.3	Street Lighting and Signal Systems - H.P.S.					
14							
15	**General and Intangible Plant**						
	301	Organization		Non Depr		Non Depr	
	302	Franchises and Consents		Non Depr		Non dear	
16	303	Intangible Plant				0	
	303.1	Intangible Plant - Software		5-SQ			
	303.2	Intangible Plant - Fiber Optic		15-SQ			
17	389	Land and Land Rights					
	389.1	Land and Land Rights - Land		Non Depr		Non Depr	
	389.2	Land and Land Rights - Land Rights	0	65-R4		0	
18	390	Structures and Improvements	0			0	
	390.1	Structures and Improvements - Leasehold Improvements					
	390	Structures and Improvements - Major		60-SQ			

	SUMMARY OF NET SALVAGE RECOMMENDATIONS						
	Client		Reliant Energy	PPL Electric Corporation	Owen Electric Cooperative	Oklahoma Gas and Electric	Oklahoma Gas and Electric (Holding Co.)
	390	Structures and Improvements - Other		45-R3			
	391	Office Furniture and Equipment	0			0	0
19	391	Office Furniture and Equipment - Equipment		15-SQ			0
20	391	Office Furniture and Equipment - Furniture		20-SQ			
45	391	Office Furniture and Equipment - Hardware (PCs)	0	5-SQ			0
47	391	Office Furniture and Equipment - Software		7-SQ			0
	392	Transportation Equipment					
200	392.1	Transportation Equipment - Cars	15	5-SQ		10	10
300	392.2	Transportation Equipment - Light Trucks	15	8-SQ		10	10
	392.21	Transportation Equipment - Pickup Trucks		15-SQ		10	10
400	392.3	Transportation Equipment - Heavy Trucks		10-SQ		10	10
	392.4	Transportation Equipment - Airplanes and Helicopters					
	392.5	Transportation Equipment - Trailers		16-L1		10	10
	392.6	Transportation Equipment - Other		20-SQ			10
23	393	Stores Equipment	0	25-SQ		0	
24	394	Tools, Shop and Garage Equipment	0	20-SQ			0
	394.1	Tools, Shop and Garage Equipment - Electric Vehicles					
500	395	Laboratory Equipment	0	20-SQ		0	0
700	396	Power Operated Equipment	15	15-SQ		5	5
800	397	Communication Equipment	0	15-SQ		0	0
	397.1	Communication Equipment - Trans Line					
	397.2	Communication Equipment - EMS					
	397.3	Communication Equipment - Fiber Optic					
900	398	Miscellaneous Equipment	0	20-SQ		0	0
25	399	Other Tangible Property					

	SUMMARY OF NET SALVAGE RECOMMENDATIONS						
	Client		Cincinnati Gas and Electric Company	Arizona Public Service Company	AmerenUE	Duquesne Light Company	Metropolitan Edison Company
	Depreciation Method		SL Rem Life	SL Rem Life	SL Whole Life (w/ 20Yr.True-up)	Sl Rem Life	SL Rem Life
	Purpose of Study						
	Study Data Year		2003	2002	2000	2001	1999
	FERC Account						
GF Order	Account No.	Description					
	Production Plant						
1	310 - 316	Steam Production					
	310	Steam Production - Land and Land Rights		Non Depr	Non Depr		
	310.1	Steam Production - Land and Land Rights - Land					
	310.2	Steam Production - Land and Land Rights - Land Rights	EXPENSED				
	311	Steam Production - Structures and Improvements	EXPENSED	(20)	(24) - (60)		
23	312	Steam Production - Boiler Plant Equipment	EXPENSED	(20)	(24) - (60)		
	312.2	Steam Production - Boiler Plant Equipment - Coal Cars			30		
	312.3	Steam Production - Boiler Plant Equipment - Scrubbers					
	313	Engines and Engine Driven Generators					
	314	Steam Production - Turbogenerator Units	EXPENSED	(20)	(24) - (60)		
	315	Steam Production - Accessory Electric Equipment	EXPENSED	(20)	(24) - (60)		
	316	Steam Production - Miscellaneous Power Plant Equipment	EXPENSED	(20)	(24) - (60)		
	316.1	Steam Production - Miscellaneous Power Plant Equipment - Shop	EXPENSED				
	316.2	Steam Production - Miscellaneous Power Plant Equipment - Other					
	320 - 325	Nuclear Production					
	320	Nuclear Production - Land and Land Rights		Non Depr	Non Depr		
	320.1	Nuclear Production - Land and Land Rights - Land					
	320.2	Nuclear Production - Land and Land Rights - Land Rights					
	321	Nuclear Production - Structures and Improvements		0	0		
	322	Nuclear Production - Reactor Plant Equipment		(2)	0		
	322.1	Nuclear Production - Reactor Plant Equipment - Steam Generators		(17)			
	323	Nuclear Production - Turbogenerator Units		(2)	0		
	324	Nuclear Production - Accessory Electric Equipment		(2)	0		
	325	Nuclear Production - Miscellaneous Power Plant Equipment		(2)	0		
24	330 - 336	Hydraulic Production					
2	330	Hydraulic Production -Land and Land Rights		Non Depr	Non Depr		
	330.1	Hydraulic Production -Land and Land Rights - Land					
	330.2	Hydraulic Production -Land and Land Rights - Land Rights					
25	331	Hydraulic Production - Structures and Improvements		0	(10)		
17	332	Hydraulic Production - Reservoirs, Dams and Waterways		0	(20)		
27	333	Hydraulic Production - Water Wheels, Turbines and Generators		0	(10)		
29	334	Hydraulic Production - Accessory Electric Equipment		0	0		
15	335	Hydraulic Production - Miscellaneous Power Plant Equipment		0	0		
16	336	Hydraulic Production - Roads, Railroads and Bridges		0	0		
3	340 - 346	Other Production					
	340 - 346	Other Production - Solar		0			
	340	Other Production -Land and Land Rights		Non Depr	Non Depr		
	340.1	Other Production -Land and Land Rights - Land					
	340.2	Other Production -Land and Land Rights - Land Rights	EXPENSED				
6	341	Other Production - Structures and Improvements	EXPENSED	(5)	(5)		
13	342	Other Production - Fuel Holders, Producers and Accessories	EXPENSED	(5)	(5)		
7	343	Other Production - Prime Movers	EXPENSED	0			
	343.1	Other Production - Prime Movers - Fuel Cells					
	343.2	Other Production - Prime Movers - Base Load					
	343.3	Other Production - Prime Movers - Peakers					
	344	Other Production - Generators	EXPENSED	), (2) West Phoeni	(5)		
12	345	Other Production - Accessory Electric Equipment	EXPENSED	0	(5)		
	346	Other Production - Miscellaneous Power Plant Equipment	EXPENSED	0	(5)		
1							
2							
3	**Transmission Plant**						
4	350	Land and Land Rights		Non Depr	Non Depr	Non Depr	
	350.1	Land and Land Rights - Land					Non Depr
	350.2	Land and Land Rights - Land Rights					AMORTIZED
40	352	Structures and Improvements		(5)	(5)		AMORTIZED
	352.1	Structures and Improvements - Major				AMORTIZED	
	352.2	Structures and Improvements - Small				AMORTIZED	
1700	353	Station Equipment		0	0	AMORTIZED	AMORTIZED
	353.2	Station Equipment - Power Supply Company	EXPENSED				
	353	Station Equipment - 1970 & Prior					
	353	Station Equipment - 1971 & Subsequent					
	353.1	Station Equipment - Substation on Customer Premises					
	353.2	Station Equipment - Portable Property at Substations					
	353.3	Station Equipment - Metering Station					

	SUMMARY OF NET SALVAGE RECOMMENDATIONS						
	Client		Cincinnati Gas and Electric Company	Arizona Public Service Company	AmerenUE	Duquesne Light Company	Metropolitan Edison Company
	353.4	Station Equipment - Control Equipment					
22	354	Towers and Fixtures		(35)	(7)	AMORTIZED	AMORTIZED
	354.1	Towers and Fixtures - Clearing Right of Way					
31	355	Poles and Fixtures			(90)	AMORTIZED	AMORTIZED
	355.1	Poles and Fixtures - Clearing Right of Way					
	355.2	Poles and Fixtures - Wood		(35)			
	355.3	Poles and Fixtures - Steel		(15)			
33	356	Overhead Conductors and Devices		(35)	(25)	AMORTIZED	AMORTIZED
	356.1	Overhead Conductors and Devices - Clearing of Rights of Way					AMORTIZED
34	357	Underground Conduit		(10)		AMORTIZED	
35	358	Underground Conductors and Devices		(10)		AMORTIZED	
	358.1	Underground Conductors and Devices - Submarine					
39	359	Roads and Trails			0	AMORTIZED	AMORTIZED
48							
600							
1600	Distribution Plant						
1800	360	Land and Land Rights		Non Depr	Non Depr	Non Depr	
	360.1	Land and Land Rights - Land					Non Depr
	360.2	Land and Land Rights - Land Rights					AMORTIZED
1900	361	Structures and Improvements		(10)	(5)		AMORTIZED
	361.1	Structures and Improvements - Major				AMORTIZED	
	361.2	Structures and Improvements - Small				AMORTIZED	
2000	362	Station Equipment		0	(5)		AMORTIZED
	362.1	Station Equipment - Company Stations				AMORTIZED	
	362.2	Station Equipment - Customer High Tension				AMORTIZED	
	362.3	Station Equipment - SCADA					
5	364	Poles, Towers and Fixtures			(135)	AMORTIZED	AMORTIZED
	364.1	Poles, Towers and Fixtures - Clearing Right of Way					
	364.2	Poles, Towers and Fixtures - Towers					
	364.4	Poles, Towers and Fixtures - Poles					
	364.6	Poles, Towers and Fixtures - Clearing Towers					
	364.8	Poles, Towers and Fixtures - Clearing Poles					
	364.9	Poles, Towers and Fixtures - Wood		(10)			
	364.10	Poles, Towers and Fixtures - Steel		(5)			
6	365	Overhead Conductors and Devices		(10)	(50)	AMORTIZED	AMORTIZED
	365.1	Sodium Vapor Security Lights					
	365.2	Overhead Conductors and Devices - Clearing Rights of Way					AMORTIZED
7	366	Underground Conduit		(5)	(50)	AMORTIZED	AMORTIZED
	366.1	Underground Conduit - Not encased					
	366.2	Underground Conduit - Manholes and Vaults					
	366.3	Underground Conduit - Encased					
9	367	Underground Conductors and Devices		(5)	(25)	AMORTIZED	AMORTIZED
	367.1	Underground Conductors and Devices - Clearing Right of Way					
44	368	Line Transformers		(5)	0		AMORTIZED
	368.1	Line Transformers - Pole Top				AMORTIZED	
	368.2	Line Transformers - Pad Mounted				AMORTIZED	
	368.3	Line Transformers - Non-Network Housing					
	368.4	Line Transformers - Network				AMORTIZED	
	368.5	Line Transformers - Underground Residential Distribution				AMORTIZED	
46	369	Services		(10)		AMORTIZED	
	369.1	Services - Overhead			(180)		AMORTIZED
	369.2	Services - Underground			(70)		AMORTIZED
100	370	Meters		0	0	AMORTIZED	AMORTIZED
	370.2	Meters - AMR and Electronic		0		AMORTIZED	
11	371	Installations on Customer Premises		(20)	0		AMORTIZED
	371.2	Installations on Customer Premises - Area Lighting					AMORTIZED
	372	Leased Property on Customer Premises					
12	373	Street Lighting and Signal Systems		(20)	(45)	AMORTIZED	AMORTIZED
	373.1	Street Lighting and Signal Systems - Clearing					
	373.2	Street Lighting and Signal Systems - M.V.					
13	373.3	Street Lighting and Signal Systems - H.P.S.					
14							
15	General and Intangible Plant						
	301	Organization					Non Depr
	302	Franchises and Consents					Non Depr
16	303	Intangible Plant					AMORTIZED
	303.1	Intangible Plant - Software					
	303.2	Intangible Plant - Fiber Optic					
17	389	Land and Land Rights		Non Depr	Non Depr	Non Depr	
	389.1	Land and Land Rights - Land					Non Depr
	389.2	Land and Land Rights - Land Rights					AMORTIZED
18	390	Structures and Improvements		(15)	(5)		
	390.1	Structures and Improvements - Leasehold Improvements					
	390	Structures and Improvements - Major				AMORTIZED	AMORTIZED

SUMMARY OF NET SALVAGE RECOMMENDATIONS

	Client		Cincinnati Gas and Electric Company	Arizona Public Service Company	AmerenUE	Duquesne Light Company	Metropolitan Edison Company
	390	Structures and Improvements - Other				AMORTIZED	AMORTIZED
	391	Office Furniture and Equipment			1		
19	391	Office Furniture and Equipment - Equipment		0		AMORTIZED	
20	391	Office Furniture and Equipment - Furniture		0		AMORTIZED	AMORTIZED
45	391	Office Furniture and Equipment - Hardware (PCs)		0	0, 1 (PCs)	AMORTIZED	AMORTIZED
47	391	Office Furniture and Equipment - Software					
	392	Transportation Equipment			10		
200	392.1	Transportation Equipment - Cars				AMORTIZED	
300	392.2	Transportation Equipment - Light Trucks					
	392.21	Transportation Equipment - Pickup Trucks					
400	392.3	Transportation Equipment - Heavy Trucks					AMORTIZED
	392.4	Transportation Equipment - Airplanes and Helicopters					
	392.5	Transportation Equipment - Trailers					AMORTIZED
	392.6	Transportation Equipment - Other				AMORTIZED	
23	393	Stores Equipment		0	0	AMORTIZED	AMORTIZED
24	394	Tools, Shop and Garage Equipment		0	3	AMORTIZED	
	394.1	Tools, Shop and Garage Equipment - Electric Vehicles					
500	395	Laboratory Equipment		0	0	AMORTIZED	
700	396	Power Operated Equipment			20	AMORTIZED	AMORTIZED
800	397	Communication Equipment		0	0	AMORTIZED	AMORTIZED
	397.1	Communication Equipment - Trans Line					
	397.2	Communication Equipment - EMS					AMORTIZED
	397.3	Communication Equipment - Fiber Optic					
900	398	Miscellaneous Equipment		0	0	AMORTIZED	AMORTIZED
25	399	Other Tangible Property					

SUMMARY OF NET SALVAGE RECOMMENDATIONS

GF Order	Account No.	Description	Bangor Hydro Electric Company	Pennsylvania Electric Company	Omaha Public Power District	PSI Energy, Inc.	Kentucky Utilities
	Client		Bangor Hydro Electric Company	Pennsylvania Electric Company	Omaha Public Power District	PSI Energy, Inc.	Kentucky Utilities
	Depreciation Method		SL Whole Life (w/ Rem Life True-up)	SL Rem Life	SL Rem Life	SL Rem Life	SL Rem Life
	Purpose of Study						
	Study Data Year		2002	1999	2007	2002	2006
	FERC Account						
GF Order	Account No.	Description					
	Production Plant						
1	310 - 316	Steam Production					
	310	Steam Production - Land and Land Rights			Non Depr	Non Depr	
	310.1	Steam Production - Land and Land Rights - Land					
	310.2	Steam Production - Land and Land Rights - Land Rights					0
	311	Steam Production - Structures and Improvements			(32)	(35)	(5)
23	312	Steam Production - Boiler Plant Equipment			(32)	(30)	(20)
	312.2	Steam Production - Boiler Plant Equipment - Coal Cars				(25)	
	312.3	Steam Production - Boiler Plant Equipment - Scrubbers					
	313	Engines and Engine Driven Generators					
	314	Steam Production - Turbogenerator Units			(32)	(30)	(15)
	315	Steam Production - Accessory Electric Equipment			(32)	(10)	(5)
	316	Steam Production - Miscellaneous Power Plant Equipment			(32)	(5)	0
	316.1	Steam Production - Miscellaneous Power Plant Equipment - Shop					
	316.2	Steam Production - Miscellaneous Power Plant Equipment - Other					
	320 - 325	Nuclear Production					
	320	Nuclear Production - Land and Land Rights					
	320.1	Nuclear Production - Land and Land Rights - Land					
	320.2	Nuclear Production - Land and Land Rights - Land Rights					
	321	Nuclear Production - Structures and Improvements			(10)		
	322	Nuclear Production - Reactor Plant Equipment			(15)		
	322.1	Nuclear Production - Reactor Plant Equipment - Steam Generators					
	323	Nuclear Production - Turbogenerator Units			(10)		
	324	Nuclear Production - Accessory Electric Equipment			(10)		
	325	Nuclear Production - Miscellaneous Power Plant Equipment			(15)		
24	330 - 336	Hydraulic Production					
2	330	Hydraulic Production -Land and Land Rights					
	330.1	Hydraulic Production -Land and Land Rights - Land					
	330.2	Hydraulic Production -Land and Land Rights - Land Rights					0
25	331	Hydraulic Production - Structures and Improvements				(20)	(5)
17	332	Hydraulic Production - Reservoirs, Dams and Waterways				(20)	0
27	333	Hydraulic Production - Water Wheels, Turbines and Generators				(10)	(10)
29	334	Hydraulic Production - Accessory Electric Equipment				0	0
15	335	Hydraulic Production - Miscellaneous Power Plant Equipment				0	0
16	336	Hydraulic Production - Roads, Railroads and Bridges					0
3	340 - 346	Other Production					
	340 - 346	Other Production - Solar					
	340	Other Production -Land and Land Rights	Non Depr		Non Depr	Non Depr	
	340.1	Other Production -Land and Land Rights - Land					
	340.2	Other Production -Land and Land Rights - Land Rights					0
6	341	Other Production - Structures and Improvements	0 - (10)		(5)	(5)	0
13	342	Other Production - Fuel Holders, Producers and Accessories	(5)		0	(5)	(5)
7	343	Other Production - Prime Movers	0		0	(10)	(5)
	343.1	Other Production - Prime Movers - Fuel Cells					
	343.2	Other Production - Prime Movers - Base Load					
	343.3	Other Production - Prime Movers - Peakers					
	344	Other Production - Generators	0		(5)	0	(5)
12	345	Other Production - Accessory Electric Equipment			0	0	0
	346	Other Production - Miscellaneous Power Plant Equipment	0		0	0	0
1							
2							
3	**Transmission Plant**						
4	350	Land and Land Rights	Non Depr		Non Depr		
	350.1	Land and Land Rights - Land		Non Depr		Non Depr	
	350.2	Land and Land Rights - Land Rights		AMORTIZED		0	0
40	352	Structures and Improvements		AMORTIZED	(15)	0	(25)
	352.1	Structures and Improvements - Major					
	352.2	Structures and Improvements - Small					
1700	353	Station Equipment	(5)	AMORTIZED	(5)	(10)	(20)
	353.2	Station Equipment - Power Supply Company					
	353	Station Equipment - 1970 & Prior					
	353	Station Equipment - 1971 & Subsequent					
	353.1	Station Equipment - Substation on Customer Premises					
	353.2	Station Equipment - Portable Property at Substations					
	353.3	Station Equipment - Metering Station					

	SUMMARY OF NET SALVAGE RECOMMENDATIONS						
	Client		Bangor Hydro Electric Company	Pennsylvania Electric Company	Omaha Public Power District	PSI Energy, Inc.	Kentucky Utilities
	353.4	Station Equipment - Control Equipment	0				
22	354	Towers and Fixtures	(15)	AMORTIZED	(25)	(10)	(25)
	354.1	Towers and Fixtures - Clearing Right of Way					
31	355	Poles and Fixtures	(20)	AMORTIZED	(30)	(60)	(60)
	355.1	Poles and Fixtures - Clearing Right of Way					
	355.2	Poles and Fixtures - Wood					
	355.3	Poles and Fixtures - Steel					
33	356	Overhead Conductors and Devices	(10)	AMORTIZED	(20)	(40)	(50)
	356.1	Overhead Conductors and Devices - Clearing of Rights of Way		AMORTIZED			
34	357	Underground Conduit	0	AMORTIZED	0	(25)	0
35	358	Underground Conductors and Devices	0		0	0	0
	358.1	Underground Conductors and Devices - Submarine					
39	359	Roads and Trails	0	AMORTIZED			
48							
600							
1600	Distribution Plant						
1800	360	Land and Land Rights	Non Depr		Non Depr		Non Depr
	360.1	Land and Land Rights - Land		Non Depr		Non Depr	
	360.2	Land and Land Rights - Land Rights	0	AMORTIZED		0	0
1900	361	Structures and Improvements	(15)	AMORTIZED		0	(10)
	361.1	Structures and Improvements - Major			(5)		
	361.2	Structures and Improvements - Small			(5)		
2000	362	Station Equipment	0	AMORTIZED	(10)	(15)	(15)
	362.1	Station Equipment - Company Stations					
	362.2	Station Equipment - Customer High Tension					
	362.3	Station Equipment - SCADA	0				
5	364	Poles, Towers and Fixtures	(20)		(15)	(50)	(45)
	364.1	Poles, Towers and Fixtures - Clearing Right of Way					
	364.2	Poles, Towers and Fixtures - Towers					
	364.4	Poles, Towers and Fixtures - Poles					
	364.6	Poles, Towers and Fixtures - Clearing Towers					
	364.8	Poles, Towers and Fixtures - Clearing Poles					
	364.9	Poles, Towers and Fixtures - Wood					
	364.10	Poles, Towers and Fixtures - Steel					
6	365	Overhead Conductors and Devices	(15)	AMORTIZED	(15)	(55)	(75)
	365.1	Sodium Vapor Security Lights					
	365.2	Overhead Conductors and Devices - Clearing Rights of Way		AMORTIZED			
7	366	Underground Conduit	(5)	AMORTIZED	(20)	(25)	0
	366.1	Underground Conduit - Not encased					
	366.2	Underground Conduit - Manholes and Vaults					
	366.3	Underground Conduit - Encased					
9	367	Underground Conductors and Devices	0	AMORTIZED	(10)	(25)	(5)
	367.1	Underground Conductors and Devices - Clearing Right of Way					
44	368	Line Transformers	(5)	AMORTIZED	(15)	(10)	(20)
	368.1	Line Transformers - Pole Top					
	368.2	Line Transformers - Pad Mounted					
	368.3	Line Transformers - Non-Network Housing					
	368.4	Line Transformers - Network					
	368.5	Line Transformers - Underground Residential Distribution					
46	369	Services	(15)		(35)		(30)
	369.1	Services - Overhead		AMORTIZED		(60)	
	369.2	Services - Underground		AMORTIZED		(30)	
100	370	Meters	0	AMORTIZED	(5)	0	0
	370.2	Meters - AMR and Electronic	0				
11	371	Installations on Customer Premises		AMORTIZED	(15)	(5)	(10)
	371.2	Installations on Customer Premises - Area Lighting		AMORTIZED			0
	372	Leased Property on Customer Premises		AMORTIZED			
12	373	Street Lighting and Signal Systems		AMORTIZED	(15)	(20)	(5)
	373.1	Street Lighting and Signal Systems - Clearing					
	373.2	Street Lighting and Signal Systems - M.V.	(10)				
13	373.3	Street Lighting and Signal Systems - H.P.S.	(10)				
14							
15	General and Intangible Plant						
	301	Organization	Intangible	Non Depr			
	302	Franchises and Consents	Intangible	Non Depr			
16	303	Intangible Plant	Intangible				
	303.1	Intangible Plant - Software		AMORTIZED			
	303.2	Intangible Plant - Fiber Optic					
17	389	Land and Land Rights	Non Depr		Non Depr	Non Depr	Non Depr
	389.1	Land and Land Rights - Land		Non Depr			
	389.2	Land and Land Rights - Land Rights		AMORTIZED			
18	390	Structures and Improvements					(5)
	390.1	Structures and Improvements - Leasehold Improvements					(5)
	390	Structures and Improvements - Major	50	AMORTIZED	0	0	

SUMMARY OF NET SALVAGE RECOMMENDATIONS

	Client		Bangor Hydro Electric Company	Pennsylvania Electric Company	Omaha Public Power District	PSI Energy, Inc.	Kentucky Utilities
	390	Structures and Improvements - Other	0	AMORTIZED	(5)	(5)	
	391	Office Furniture and Equipment				0	0
19	391	Office Furniture and Equipment - Equipment	0	AMORTIZED			0
20	391	Office Furniture and Equipment - Furniture	0	AMORTIZED			
45	391	Office Furniture and Equipment - Hardware (PCs)	0	AMORTIZED	0	0	0
47	391	Office Furniture and Equipment - Software					
	392	Transportation Equipment			15		
200	392.1	Transportation Equipment - Cars	10				
300	392.2	Transportation Equipment - Light Trucks		AMORTIZED			
	392.21	Transportation Equipment - Pickup Trucks					
400	392.3	Transportation Equipment - Heavy Trucks		AMORTIZED			
	392.4	Transportation Equipment - Airplanes and Helicopters					
	392.5	Transportation Equipment - Trailers		AMORTIZED		10	
	392.6	Transportation Equipment - Other					
23	393	Stores Equipment	0	AMORTIZED		0	0
24	394	Tools, Shop and Garage Equipment	0	AMORTIZED		0	0
	394.1	Tools, Shop and Garage Equipment - Electric Vehicles					
500	395	Laboratory Equipment		AMORTIZED		0	0
700	396	Power Operated Equipment	10	AMORTIZED	35	0	0
800	397	Communication Equipment	0	AMORTIZED	0	0	0
	397.1	Communication Equipment - Trans Line					
	397.2	Communication Equipment - EMS		AMORTIZED			
	397.3	Communication Equipment - Fiber Optic					
900	398	Miscellaneous Equipment	0	AMORTIZED		0	0
25	399	Other Tangible Property					

GF Order	Account No.	Description	El Paso Electric Company	Duke Power Company	Nevada Power Company	Chugach Electric Association, Inc	Puget Sound Energy
	SUMMARY OF NET SALVAGE RECOMMENDATIONS						
	Client		El Paso Electric Company	Duke Power Company	Nevada Power Company	Chugach Electric Association, Inc	Puget Sound Energy
	Depreciation Method		SL Rem Life	Sl Rem Life	SL Rem Life	SL Rem. Life	SL Rem. Life
	Purpose of Study						
	Study Data Year		2002	2003	2006	2002	2007
		FERC Account					
GF Order	Account No.	Description					
	Production Plant						
1	310 - 316	Steam Production					
	310	Steam Production - Land and Land Rights	Non Depr				
	310.1	Steam Production - Land and Land Rights - Land		Non Depr	Non Depr		
	310.2	Steam Production - Land and Land Rights - Land Rights		0	0		
	311	Steam Production - Structures and Improvements	(5), 0 (Four Corners)	(20)	(9)	(5)	(10)
23	312	Steam Production - Boiler Plant Equipment	(10), 0 (Four Corners)	(20)	(9)	(10)	(10)
	312.2	Steam Production - Boiler Plant Equipment - Coal Cars					
	312.3	Steam Production - Boiler Plant Equipment - Scrubbers					
	313	Engines and Engine Driven Generators	(10)				
	314	Steam Production - Turbogenerator Units	(10), 0 (Four Corners)	(20)	(9)	(5)	(10)
	315	Steam Production - Accessory Electric Equipment	0	(20)	(9)	(5)	0
	316	Steam Production - Miscellaneous Power Plant Equipment	0	(20)	(9)	0	0
	316.1	Steam Production - Miscellaneous Power Plant Equipment - Shop					
	316.2	Steam Production - Miscellaneous Power Plant Equipment - Other					
	320 - 325	Nuclear Production					
	320	Nuclear Production - Land and Land Rights					
	320.1	Nuclear Production - Land and Land Rights - Land		Non Depr			
	320.2	Nuclear Production - Land and Land Rights - Land Rights		0			
	321	Nuclear Production - Structures and Improvements		(2)			
	322	Nuclear Production - Reactor Plant Equipment		(2)			
	322.1	Nuclear Production - Reactor Plant Equipment - Steam Generators					
	323	Nuclear Production - Turbogenerator Units		(2)			
	324	Nuclear Production - Accessory Electric Equipment		(2)			
	325	Nuclear Production - Miscellaneous Power Plant Equipment		(2)			
24	330 - 336	Hydraulic Production					
2	330	Hydraulic Production -Land and Land Rights					
	330.1	Hydraulic Production -Land and Land Rights - Land		Non Depr			
	330.2	Hydraulic Production -Land and Land Rights - Land Rights		0			
25	331	Hydraulic Production - Structures and Improvements		(15)		(5)	(25)
17	332	Hydraulic Production - Reservoirs, Dams and Waterways		(15)		(25)	(25)
27	333	Hydraulic Production - Water Wheels, Turbines and Generators		(15)		(10)	0
29	334	Hydraulic Production - Accessory Electric Equipment		(15)		0	0
15	335	Hydraulic Production - Miscellaneous Power Plant Equipment		(15)		0	0
16	336	Hydraulic Production - Roads, Railroads and Bridges		(15)		0	0
3	340 - 346	Other Production					
	340 - 346	Other Production - Solar					
	340	Other Production -Land and Land Rights	Non Depr			Non Depr	
	340.1	Other Production -Land and Land Rights - Land		Non Depr			
	340.2	Other Production -Land and Land Rights - Land Rights			0		
6	341	Other Production - Structures and Improvements	0	(8)	-17	(5)	(5)
13	342	Other Production - Fuel Holders, Producers and Accessories	0	(8)	-17	(10)	(5)
7	343	Other Production - Prime Movers		(8)	-17		
	343.1	Other Production - Prime Movers - Fuel Cells				0	
	343.2	Other Production - Prime Movers - Base Load				0	
	343.3	Other Production - Prime Movers - Peakers				0	
	344	Other Production - Generators	0	(8)	-17	0	0
12	345	Other Production - Accessory Electric Equipment	0	(8)	-17	0	0
	346	Other Production - Miscellaneous Power Plant Equipment	0	(8)	-17	0	0
1							
2							
3	**Transmission Plant**						
4	350	Land and Land Rights				Non Depr	
	350.1	Land and Land Rights - Land		Non Depr	Non Depr		
	350.2	Land and Land Rights - Land Rights	0	0	0		
40	352	Structures and Improvements		(20)	-10	(5)	(5)
	352.1	Structures and Improvements - Major	0				
	352.2	Structures and Improvements - Small	0				
1700	353	Station Equipment	(5), 0 (Four Corners)	(20)	5	(5)	(10)
	353.2	Station Equipment - Power Supply Company					
	353	Station Equipment - 1970 & Prior					
	353	Station Equipment - 1971 & Subsequent					
	353.1	Station Equipment - Substation on Customer Premises					
	353.2	Station Equipment - Portable Property at Substations					
	353.3	Station Equipment - Metering Station					

	SUMMARY OF NET SALVAGE RECOMMENDATIONS						
	Client		El Paso Electric Company	Duke Power Company	Nevada Power Company	Chugach Electric Association, Inc	Puget Sound Energy
	353.4	Station Equipment - Control Equipment				0	
22	354	Towers and Fixtures	(25), 0 (Four Corners)	(20)	(25)	(20)	(20)
	354.1	Towers and Fixtures - Clearing Right of Way					
31	355	Poles and Fixtures	(20)	(20)	(20)	(20)	(30)
	355.1	Poles and Fixtures - Clearing Right of Way					
	355.2	Poles and Fixtures - Wood					
	355.3	Poles and Fixtures - Steel					
33	356	Overhead Conductors and Devices	0	(20)	(10)	(10)	(20)
	356.1	Overhead Conductors and Devices - Clearing of Rights of Way					
34	357	Underground Conduit		(20)	0	(5)	
35	358	Underground Conductors and Devices		(20)	0	0	0
	358.1	Underground Conductors and Devices - Submarine				(2) (So.), 0 (No.)	
39	359	Roads and Trails	0		0	0	0
48							
600							
1600	**Distribution Plant**						
1800	360	Land and Land Rights				Non Depr	
	360.1	Land and Land Rights - Land		Non Depr	Non Depr		
	360.2	Land and Land Rights - Land Rights	0	0	0		
1900	361	Structures and Improvements	0	(10)	(5)	(5)	(5)
	361.1	Structures and Improvements - Major					
	361.2	Structures and Improvements - Small					
2000	362	Station Equipment	(5)	(10)	(10)	(5)	(10)
	362.1	Station Equipment - Company Stations					
	362.2	Station Equipment - Customer High Tension					
	362.3	Station Equipment - SCADA				0	
5	364	Poles, Towers and Fixtures	(25)	(10)	(25)	(30)	(30)
	364.1	Poles, Towers and Fixtures - Clearing Right of Way					
	364.2	Poles, Towers and Fixtures - Towers					
	364.4	Poles, Towers and Fixtures - Poles					
	364.6	Poles, Towers and Fixtures - Clearing Towers					
	364.8	Poles, Towers and Fixtures - Clearing Poles					
	364.9	Poles, Towers and Fixtures - Wood					
	364.10	Poles, Towers and Fixtures - Steel					
6	365	Overhead Conductors and Devices	(20)	(10)	5	(20)	(20)
	365.1	Sodium Vapor Security Lights					
	365.2	Overhead Conductors and Devices - Clearing Rights of Way					
7	366	Underground Conduit	(5)	(10)	(20)	(10)	(15)
	366.1	Underground Conduit - Not encased					
	366.2	Underground Conduit - Manholes and Vaults					
	366.3	Underground Conduit - Encased					
9	367	Underground Conductors and Devices	(5)	(10)	15	(5), 0 (Cable II)	(20)
	367.1	Underground Conductors and Devices - Clearing Right of Way					
44	368	Line Transformers	(5)	(10)	5	(10)	(20)
	368.1	Line Transformers - Pole Top					
	368.2	Line Transformers - Pad Mounted					
	368.3	Line Transformers - Non-Network Housing					
	368.4	Line Transformers - Network					
	368.5	Line Transformers - Underground Residential Distribution					
46	369	Services	(30)	(10)	(50)	(25)	(20)
	369.1	Services - Overhead					
	369.2	Services - Underground					
100	370	Meters	(25)	(10)	1	5	0
	370.2	Meters - AMR and Electronic					
11	371	Installations on Customer Premises	(5)	(10)		0	
	371.2	Installations on Customer Premises - Area Lighting					
	372	Leased Property on Customer Premises			60		
12	373	Street Lighting and Signal Systems	(5)	(10)	0	(15)	(15)
	373.1	Street Lighting and Signal Systems - Clearing					
	373.2	Street Lighting and Signal Systems - M.V.					
13	373.3	Street Lighting and Signal Systems - H.P.S.					
14							
15	**General and Intangible Plant**						
	301	Organization					
	302	Franchises and Consents					
16	303	Intangible Plant			0	Non Depr	
	303.1	Intangible Plant - Software					
	303.2	Intangible Plant - Fiber Optic					
17	389	Land and Land Rights	Non Depr			Non Depr	
	389.1	Land and Land Rights - Land			Non Depr		
	389.2	Land and Land Rights - Land Rights		0	0		
18	390	Structures and Improvements		5	(5)	0	(5)
	390.1	Structures and Improvements - Leasehold Improvements				0	
	390	Structures and Improvements - Major	0				

	SUMMARY OF NET SALVAGE RECOMMENDATIONS						
	Client		El Paso Electric Company	Duke Power Company	Nevada Power Company	Chugach Electric Association, Inc	Puget Sound Energy
	390	Structures and Improvements - Other	0			0	
	391	Office Furniture and Equipment	0	5	0	0	0
19	391	Office Furniture and Equipment - Equipment					
20	391	Office Furniture and Equipment - Furniture					
45	391	Office Furniture and Equipment - Hardware (PCs)		5	0	0	0
47	391	Office Furniture and Equipment - Software					
	392	Transportation Equipment			10	10	10
200	392.1	Transportation Equipment - Cars		30			
300	392.2	Transportation Equipment - Light Trucks		30			
	392.21	Transportation Equipment - Pickup Trucks		30			
400	392.3	Transportation Equipment - Heavy Trucks		30			
	392.4	Transportation Equipment - Airplanes and Helicopters					
	392.5	Transportation Equipment - Trailers		30			
	392.6	Transportation Equipment - Other					
23	393	Stores Equipment	0	5	0	0	0
24	394	Tools, Shop and Garage Equipment	0	5	0	0	0
	394.1	Tools, Shop and Garage Equipment - Electric Vehicles					
500	395	Laboratory Equipment	0	5	0	0	0
700	396	Power Operated Equipment	15	30	10	10	10
800	397	Communication Equipment	0	5	0	0	0
	397.1	Communication Equipment - Trans Line					
	397.2	Communication Equipment - EMS					
	397.3	Communication Equipment - Fiber Optic					
900	398	Miscellaneous Equipment	0	5	0	0, Non Depr	0
25	399	Other Tangible Property					

	SUMMARY OF NET SALVAGE RECOMMENDATIONS			
	Client		Idaho Power Company	Louisville Gas & Electric
	Depreciation Method		SL Rem. Life	SL Rem. Life
	Purpose of Study			
	Study Data Year		2007	2007
	FERC Account			
GF Order	Account No.	Description		
	Production Plant			
1	310 - 316	Steam Production		
	310	Steam Production - Land and Land Rights		
	310.1	Steam Production - Land and Land Rights - Land		
	310.2	Steam Production - Land and Land Rights - Land Rights		
	311	Steam Production - Structures and Improvements	(10)	(10)
23	312	Steam Production - Boiler Plant Equipment	(5)	(30)
	312.2	Steam Production - Boiler Plant Equipment - Coal Cars	20	
	312.3	Steam Production - Boiler Plant Equipment - Scrubbers	(5)	
	313	Engines and Engine Driven Generators		
	314	Steam Production - Turbogenerator Units	(5)	(10)
	315	Steam Production - Accessory Electric Equipment	0	(5)
	316	Steam Production - Miscellaneous Power Plant Equipment	(5)	(5)
	316.1	Steam Production - Miscellaneous Power Plant Equipment - Shop		
	316.2	Steam Production - Miscellaneous Power Plant Equipment - Other		
	320 - 325	Nuclear Production		
	320	Nuclear Production - Land and Land Rights		
	320.1	Nuclear Production - Land and Land Rights - Land		
	320.2	Nuclear Production - Land and Land Rights - Land Rights		
	321	Nuclear Production - Structures and Improvements		
	322	Nuclear Production - Reactor Plant Equipment		
	322.1	Nuclear Production - Reactor Plant Equipment - Steam Generators		
	323	Nuclear Production - Turbogenerator Units		
	324	Nuclear Production - Accessory Electric Equipment		
	325	Nuclear Production - Miscellaneous Power Plant Equipment		
24	330 - 336	Hydraulic Production		
2	330	Hydraulic Production -Land and Land Rights		
	330.1	Hydraulic Production -Land and Land Rights - Land		
	330.2	Hydraulic Production -Land and Land Rights - Land Rights		
25	331	Hydraulic Production - Structures and Improvements	(25)	(5)
17	332	Hydraulic Production - Reservoirs, Dams and Waterways	(20)	(5)
27	333	Hydraulic Production - Water Wheels, Turbines and Generators	(5)	(10)
29	334	Hydraulic Production - Accessory Electric Equipment	(5)	(5)
15	335	Hydraulic Production - Miscellaneous Power Plant Equipment	0	(10)
16	336	Hydraulic Production - Roads, Railroads and Bridges	0	0
3	340 - 346	Other Production		
	340 - 346	Other Production - Solar		
	340	Other Production -Land and Land Rights		
	340.1	Other Production -Land and Land Rights - Land		
	340.2	Other Production -Land and Land Rights - Land Rights		
6	341	Other Production - Structures and Improvements	0	(5)
13	342	Other Production - Fuel Holders, Producers and Accessories	0	(5)
7	343	Other Production - Prime Movers	0	(5)
	343.1	Other Production - Prime Movers - Fuel Cells		
	343.2	Other Production - Prime Movers - Base Load		
	343.3	Other Production - Prime Movers - Peakers		
	344	Other Production - Generators	0	(5)
12	345	Other Production - Accessory Electric Equipment	0	0
	346	Other Production - Miscellaneous Power Plant Equipment	0	0
1				
2				
3	**Transmission Plant**			
4	350	Land and Land Rights		
	350.1	Land and Land Rights - Land		
	350.2	Land and Land Rights - Land Rights		0
40	352	Structures and Improvements	(30)	(10)
	352.1	Structures and Improvements - Major		
	352.2	Structures and Improvements - Small		
1700	353	Station Equipment	(5)	(10)
	353.2	Station Equipment - Power Supply Company		
	353	Station Equipment - 1970 & Prior		
	353	Station Equipment - 1971 & Subsequent		
	353.1	Station Equipment - Substation on Customer Premises		
	353.2	Station Equipment - Portable Property at Substations		
	353.3	Station Equipment - Metering Station		

	SUMMARY OF NET SALVAGE RECOMMENDATIONS			
	Client		Idaho Power Company	Louisville Gas & Electric
	353.4	Station Equipment - Control Equipment		
22	354	Towers and Fixtures	(25)	(40)
	354.1	Towers and Fixtures - Clearing Right of Way		
31	355	Poles and Fixtures	(70)	(50)
	355.1	Poles and Fixtures - Clearing Right of Way		
	355.2	Poles and Fixtures - Wood		
	355.3	Poles and Fixtures - Steel		
33	356	Overhead Conductors and Devices	(30)	(40)
	356.1	Overhead Conductors and Devices - Clearing of Rights of Way		
34	357	Underground Conduit		0
35	358	Underground Conductors and Devices		0
	358.1	Underground Conductors and Devices - Submarine		
39	359	Roads and Trails	0	
48				
600				
1600	**Distribution Plant**			
1800	360	Land and Land Rights		
	360.1	Land and Land Rights - Land		
	360.2	Land and Land Rights - Land Rights		
1900	361	Structures and Improvements	(30)	(20)
	361.1	Structures and Improvements - Major		
	361.2	Structures and Improvements - Small		
2000	362	Station Equipment	(5)	(15)
	362.1	Station Equipment - Company Stations		
	362.2	Station Equipment - Customer High Tension		
	362.3	Station Equipment - SCADA		
5	364	Poles, Towers and Fixtures	(50)	(60)
	364.1	Poles, Towers and Fixtures - Clearing Right of Way		
	364.2	Poles, Towers and Fixtures - Towers		
	364.4	Poles, Towers and Fixtures - Poles		
	364.6	Poles, Towers and Fixtures - Clearing Towers		
	364.8	Poles, Towers and Fixtures - Clearing Poles		
	364.9	Poles, Towers and Fixtures - Wood		
	364.10	Poles, Towers and Fixtures - Steel		
6	365	Overhead Conductors and Devices	(40)	(50)
	365.1	Sodium Vapor Security Lights		
	365.2	Overhead Conductors and Devices - Clearing Rights of Way		
7	366	Underground Conduit	(20)	(10)
	366.1	Underground Conduit - Not encased		
	366.2	Underground Conduit - Manholes and Vaults		
	366.3	Underground Conduit - Encased		
9	367	Underground Conductors and Devices	(15)	(15)
	367.1	Underground Conductors and Devices - Clearing Right of Way		
44	368	Line Transformers	5	(20)
	368.1	Line Transformers - Pole Top		
	368.2	Line Transformers - Pad Mounted		
	368.3	Line Transformers - Non-Network Housing		
	368.4	Line Transformers - Network		
	368.5	Line Transformers - Underground Residential Distribution		
46	369	Services	(40)	
	369.1	Services - Overhead		(100)
	369.2	Services - Underground		(35)
100	370	Meters	0	(5)
	370.2	Meters - AMR and Electronic	0	
11	371	Installations on Customer Premises	(5)	
	371.2	Installations on Customer Premises - Area Lighting		
	372	Leased Property on Customer Premises		
12	373	Street Lighting and Signal Systems	(25)	(20)
	373.1	Street Lighting and Signal Systems - Clearing		
	373.2	Street Lighting and Signal Systems - M.V.		
13	373.3	Street Lighting and Signal Systems - H.P.S.		
14				
15	**General and Intangible Plant**			
	301	Organization		
	302	Franchises and Consents		
16	303	Intangible Plant		
	303.1	Intangible Plant - Software		
	303.2	Intangible Plant - Fiber Optic		
17	389	Land and Land Rights		
	389.1	Land and Land Rights - Land		
	389.2	Land and Land Rights - Land Rights		
18	390	Structures and Improvements	(5)	
	390.1	Structures and Improvements - Leasehold Improvements	0	
	390	Structures and Improvements - Major	(5)	

	SUMMARY OF NET SALVAGE RECOMMENDATIONS			
	Client		Idaho Power Company	Louisville Gas & Electric
	390	Structures and Improvements - Other		
	391	Office Furniture and Equipment	0	
19	391	Office Furniture and Equipment - Equipment	0	
20	391	Office Furniture and Equipment - Furniture		
45	391	Office Furniture and Equipment - Hardware (PCs)	0	
47	391	Office Furniture and Equipment - Software		
	392	Transportation Equipment		
200	392.1	Transportation Equipment - Cars	25	
300	392.2	Transportation Equipment - Light Trucks	25	
	392.21	Transportation Equipment - Pickup Trucks	25	
400	392.3	Transportation Equipment - Heavy Trucks	25	
	392.4	Transportation Equipment - Airplanes and Helicopters	50	
	392.5	Transportation Equipment - Trailers	25	5
	392.6	Transportation Equipment - Other		
23	393	Stores Equipment	0	
24	394	Tools, Shop and Garage Equipment	0	0
	394.1	Tools, Shop and Garage Equipment - Electric Vehicles		
500	395	Laboratory Equipment	0	0
700	396	Power Operated Equipment	30	0
800	397	Communication Equipment	0	
	397.1	Communication Equipment - Trans Line		
	397.2	Communication Equipment - EMS		
	397.3	Communication Equipment - Fiber Optic	0	
900	398	Miscellaneous Equipment	0	
25	399	Other Tangible Property		

Q.

Net Salvage Account 311. For the net salvage information on Exhibit CRC – 1, page 438 for Account 311, please provide the following:

a. A detailed categorization of what was retired;

b. The corresponding dollars for each of the items in (a) above;

c. A detailed narrative identifying what caused the $1,091,531 cost of removal level;

d. A detailed narrative identifying why this specific year of activity is representative of the remaining investment in the account.

A.

a. See FPL's response to Depreciation-OPC's First Request for Production of Documents No. 14.

b. See FPL's response to Depreciation-OPC's First Request for Production of Documents No. 14.

c. See FPL's response to Depreciation-OPC's First Request for Production of Documents No. 14.

d. No specific year was analyzed, but rather all years and bands of years. Years that looked abnormal were given less weight in the analysis. The information derived from examining all years and bands was used to determine estimated future net salvage not any one particular year. This estimate was based on the best information available and because it is based on 22 years of actual history we believe that the resulting net salvage estimate obtained is indicative of the future until new recorded information is available.

FLORIDA POWER & LIGHT

PRODUCTION PLANT INTERIM NET SALVAGE ANALYSIS

The net salvage for interim retirements was developed by analyzing the retirement, cost of removal and salvage data from 1986 to 2007. Information from Company personnel and experience in the industry were incorporated in the determination of an estimated future net salvage by account for production. Since this net salvage is only applied to future interim retirements, the net salvage percent developed for each account was adjusted for future interim retirements. Below is an account by account description of the development of net salvage percent and the tables that follow show the adjustment for future interim retirements.

Account 311 Structures and Improvements

Industry data usually shows negative net salvage for this account. Currently the approved net salvage percent is negative 9 percent. There has been some large amounts of salvage recorded in past few years but it appears the cost of removal has been increasing recently and creating negative net salvage. Looking at the history for this account shows negative 16 percent net salvage. Recommend increasing the net salvage for this account to negative 15 percent. See Attachment A for the adjustment for future interim retirements which lowers the net salvage percent to negative 5 percent.

Account 312 Boiler Plant Equipment

This account usually shows net negative salvage in the industry. The current approved net salvage percent is negative 6 percent. Cost of removal has been increasing over the past few years over 10 percent in most years. The historical data shows net salvage at negative 27 percent., the past five years show negative 13 percent and the recent years show negative 18 percent. Recommend increasing net salvage to negative 15 percent. See Attachment A for the adjustment for future interim retirements which lowers the net salvage percent to negative 11 percent.

Account 314 Turbogenerator Units

There have been considerable interim retirements in this account over the past years, however there is also high cost of removal and high salvage associated with these retirements. Some years cost of removal outweighs salvage and some years it's the other way around. Currently the approved net salvage percent is negative 2 percent. This seems too high for this account since there has been some large salvage amounts recorded in the past few years. Until we can establish a pattern for net salvage I recommend using zero percent net salvage for this account. Attachment A shows that this stays at zero percent net salvage for future interim net salvage.

Account 315 Accessory Electric Equipment

Cost of removal has been increasing in this account for a number of years. Current net salvage percent is negative 6 percent. This amount should definitely be increased according to the data. Historical net salvage shows negative 19 percent but the 5 year average shows negative 28 percent with a number of years over 30 percent. Recommend increasing net salvage percent to negative 20 percent for this account. Attachment A shows the adjustment for future interim retirements which lowers the net salvage to negative 12 percent.

Account 316 Miscellaneous Equipment

Cost of removal and salvage for this account are not that large although there is more cost of removal recorded. Current approved net salvage percent for this account is zero percent. There has been more cost of removal recorded over history and shows negative 5 percent net salvage. This has increased over the past five years which show negative 8 percent. Recommend increasing net salvage from zero percent to negative 5 percent for this account. Attachment A shows the adjustment for future interim retirements which lowers the net salvage percent to negative 4 percent.

Account 321 Structures and Improvements

This account usually shows high cost of removal and low salvage however in the past few years there has been some high salvage recorded. Currently the net salvage percent approved is negative one percent. Over the past 10 years the net salvage has been up and down. The account was showing some positive salvage but then turned negative again. Recommend lowering the net salvage to zero percent until there is a pattern in recorded amounts. Attachment A shows the adjustment for interim retirements for this account is still results in zero percent.

Account 322 Reactor Plant Equipment

During the history examined for this account the cost of removal has outweighed the salvage slightly. Current approved net salvage amount is negative 2 percent.

This amount appears justified until the recent few years when there was some large retirements with large removal and salvage recorded. These recent retirements have distorted the historical pattern showing high net negative salvage. Until we get more years of data we recommend increasing the net salvage percent slightly from the current approved to negative 5 percent. Attachment A shows the adjustment for future interim retirements for this account lowers this to negative 4 percent.

Account 323 Turbogenerator Units

This account history shows net salvage percent positive in some years and negative in other years depending on the retirement. There have been some large retirements in past few years with both high salvage and high removal costs. Current approved net salvage is negative 4 percent. Until it is determined if these large retirements will continue and a pattern of removal and salvage is established I recommend using zero net salvage percent for this account. Attachment A shows the adjustment for future interim retirements which wil continue to be zero percent.

Account 324 Accessory Electric Equipment

Retirements for this account have been fairly constant compared to some of the other nuclear accounts. Cost of removal most always exceeds salvage. The historical data shows net salvage at negative 19 percent. Current approved net salvage is negative 2 percent.. the past 5 years shows net salvage increasing to negative 41 percent. Recommend increasing current net salvage to negative 20 percent for this account. Attachment A shows the adjustment for future interim retirements lowers this to 18 percent net negative salvage.

Account 325 Miscellaneous Equipment

This account shows cost of removal and salvage high and low resulting in positive and negative net salvage. Current net salvage is negative one percent. Historical data shows the overall net salvage at positive 11 percent however the past couple of years show negative net salvage. Recommend using zero percent net salvage for this account until a pattern can be established with the recorded data. Attachment A shows the adjustment for future interim retirements results in zero net salvage percent for this account.

Account 341 Structures and Improvements

There has been large removal costs recorded for this account. There is an extremely large salvage amount recorded in 2007 which appears to be an anomaly. Current net salvage is negative 2 percent. Historical net salvage is negative 20 percent but much higher in past few years with negative 40 percent (ignoring 2007). Recommend increasing net salvage to reflect increasing cost of removal, increase to negative 25 percent. Attachment A adjusts this amount for future interim retirements and results in negative 12 percent for this account.

Account 342 Fuel Holders, Producers & Accessories

This account has a number of years with no retirements, however when there are retirements there is cost of removal and little salvage recorded, some years no salvage. Current approve net salvage is zero percent. Recommend increasing net salvage to reflect cost of removal, increase to negative 5 percent. Attachment A shows the adjustment for future interim retirements which lowers this net salvage to negative 3 percent.

Account 343 Prime Movers

The historical data shows some large retirements with high cost of removal and high salvage in some years. The historical net salvage shows negative 24 percent .Current net salvage for this account is zero percent. The last five years shows negative 14 percent net salvage. Recommend increasing net salvage to reflect the increasing cost of removal for this account. Increase to negative 10 percent. Attachment A shows the adjustment for future interim retirements which lowers the net salvage to negative 2 percent.

Account 344 Generators

Historical data shows some large retirements over past few years but extremely high removal costs. Currently the approved net salvage percent for this account is negative one percent. The five year average shows negative 136 percent. The historical net salvage percent is negative 99 percent. Based on the past five years increase the net salvage to negative 100 percent. Attachment A shows the adjustment for future interim retirements which will lower the estimate to negative 11 percent.

Account 345 Accessory Electric Equipment

Retirements for this account have been fairly stable over the years. There has been cost of removal recorded for each retirement but very little salvage and most years no salvage has been recorded. Current net salvage percent is negative one percent. Historical net salvage percent is negative 7 percent but last five years the net salvage percent is negative 14 percent. Recommend increasing net salvage to negative 10 percent. Attachment A shows the adjustment for future interim retirements lowers this estimate to negative 3 percent.

Account 346 Misc. Power Plant Equipment

Historical data shows small retirements with some cost of removal and practically no salvage. Current net salvage approved is zero percent. Historical net salvage shows negative 2 percent and the last five years is consistent with the 2 percent negative. At this time recommend retaining the current zero percent net salvage for this account. Attachment A shows the adjustment for future interim retirements retains the zero percent net salvage for this account.

Account 341
Cost of Removal

Ledger Year	Reason	Work Order	Total
2004	O=OPERATION	01365-070-0903-007 - replace psn hydrogen house roof (Site:sanford plant)	1,954.40
		01599-070-0916-007 - replace psn4 switchgear room roof (Site:sanford plant)	15,386.40
		01600-070-0916-007 - replace psn5 switchgear room roof (Site:sanford plant)	16,615.26
		01624-070-0903-007 - replace lunch room hvac system (Site:sanford plant)	2,840.00
		01715-070-0903-007 - replace psn service building roof (Site:sanford plant)	29,744.00
		01823-070-0903-007 - replace psn stores/lunchroom bldg roof (Site:sanford plant)	28,000.00
	O=OPERATION Total		94,540.06
	V=IMPROVE	01314-070-0921-007 - replace fire protection system (Site:fort lauderdale gt's)	6,121.79
		01371-070-0928-007 - replace hvac system service building (Site:martin plant)	11,700.00
		01372-070-0928-007 - replace hvac system control room building (Site:martin plant unit 3&4)	11,700.00
		01874-070-0921-007 - replace fire protection system pfl gt units 17-20 (Site:fort lauderdale gt's)	7,512.75
		09172-070-0916-006 - psn4 repowering-plant refurbishment (Site:sanford plant)	28,930.00
	V=IMPROVE Total		65,964.54
2004 Total			160,504.60
2005	O=OPERATION	02690-070-0928-007 - replace 3b intake cooling pump/motor (Site:martin plant u3)	4,660.21
		03257-070-0905-007 - replace ppn 2c acw pump motor (Site:putnam plant)	5,306.68
		09933-070-0952-006 - pmr & combined cycle conversion project (Site:martin plant un8 com cyc)	710,911.53
	O=OPERATION Total		720,878.42
2005 Total			720,878.42
2006	H=HURRICANES	03522-070-0921-007 - replace gt shop roof at pfl (Site:ft lauderdale gt's)	29,670.00
	H=HURRICANES/MAJOR STORMS Total		29,670.00
	O=OPERATION	02757-070-0921-007 - pfl gt units 21-24 fire protection system repl (Site:fort lauderdale gts)	2,000.00
		02966-070-0911-007 - replace 460sy discharge canal retaining wall (Site:ft myers plant)	6,422.03
		03593-070-0921-007 - pfl gt fire protection system replacement (Site:fort lauderdale gts)	1,439.04
		04355-070-0908-007 - pfl waste water treatment pond liner replacement (Site:fort lauderdale-common)	53,316.93
		04490-070-0905-007 - replace ppn service bldg a/c unit (Site:putnam plant)	500.00
		04491-070-0905-007 - replace ppn control room bldg a/c unit (Site:putnam plant)	500.00
	O=OPERATION Total		64,178.00
2006 Total			93,848.00
2007	O=OPERATION	02230-070-0908-007 - pfl wtp vacuum degasifier pump replacements (Site:fort lauderdale-common)	5,927.79
		04129-070-0908-007 - pfl control room bldg hvac coils replacement (Site:fort lauderdale-common)	17,500.00
		04355-070-0908-007 - pfl waste water treatment pond liner replacement (Site:fort lauderdale-common)	(27,841.41)
		04371-070-0908-007 - pfl wtp degasifier product pump/motor replacement (Site:fort lauderdale-common)	578.80
		04630-070-0911-007 - replace 2 raw water wells at pfm (Site:ft myers plant common - 505)	4,100.00

Account 341
Cost of Removal

Ledger Year	Reason	Work Order	Total
2007	O=OPERATION	04975-070-0923-007 - ppe 3 gt bldg 1 fire protection sys replacement (Site:port everglades gts)	1,352.03
		05299-070-0905-007 - replace ppn service bldg a/c (Site:putnam plant)	571.43
		05300-070-0905-007 - replace ppn shift shop bldg a/c (Site:putnam plant)	2,038.94
		05405-070-0907-007 - psn common replace storeroom hvac condensing (Site:sanford plant site common)	1,442.06
		05406-070-0907-007 - psn common replace battery room air handler (Site:sanford plant site common)	824.60
	O=OPERATION Total		6,494.24
	V=IMPROVE	05431-070-0919-007 - pfm 3b install/remove ct parts (outage) (Site:fort myers simple cycle)	109,728.05
		05754-070-0911-007 - PFM Combined Cycle Common Plant: Install Raw Water Well	950.00
	V=IMPROVE Total		110,678.05
2007 Total			117,172.29
Grand Total			1,092,403.31

Account 341.0
Retirements

Ledger Year	Reason	Work Order Number	Retirement Units	Quantity	Amount
2004	O=OPERATION	01599-070-0916-007 - replace psn4 switchgear room roof (Site:sanford plant)	ROOF	720	17,590.97
		01599-070-0916-007 - replace psn4 switchgear room roof (Site:sanford plant) Total		720	17,590.97
		01600-070-0916-007 - replace psn5 switchgear room roof (Site:sanford plant)	ROOF	720	15,403.43
		01600-070-0916-007 - replace psn5 switchgear room roof (Site:sanford plant) Total		720	15,403.43
		01624-070-0903-007 - replace lunch room hvac system (Site:sanford plant)	HVAC SYSTEM COMPLETE	1	36,375.69
		01624-070-0903-007 - replace lunch room hvac system (Site:sanford plant) Total		1	36,375.69
		01715-070-0903-007 - replace psn service building roof (Site:sanford plant)	ROOF	1,109	111,292.92
		01715-070-0903-007 - replace psn service building roof (Site:sanford plant) Total		1,109	111,292.92
		01823-070-0903-007 - replace psn stores/lunchroom bldg roof (Site:sanford plant)	ROOF	748	12,154.50
		01823-070-0903-007 - replace psn stores/lunchroom bldg roof (Site:sanford plant) Total		748	12,154.50
	O=OPERATION Total			3,298	192,817.51
	V=IMPROVE	01314-070-0921-007 - replace fire protection system (Site:fort lauderdale gt's)	SUPERSTRUCTURE	0	36,050.16
		01314-070-0921-007 - replace fire protection system (Site:fort lauderdale gt's) Total		0	36,050.16
		01371-070-0928-007 - replace hvac system service building (Site:martin plant)	HVAC SYSTEM COMPLETE	1	142,170.48
		01371-070-0928-007 - replace hvac system service building (Site:martin plant) Total		1	142,170.48
		01372-070-0928-007 - replace hvac system control room building (Site:martin plant unit 3&4)	HVAC SYSTEM COMPLETE	1	123,292.30
		01372-070-0928-007 - replace hvac system control room building (Site:martin plant unit 3&4) Total		1	123,292.30
		01874-070-0921-007 - replace fire protection system pfl gt units 17-20 (Site:fort lauderdale	SUPERSTRUCTURE	0	36,050.16
		01874-070-0921-007 - replace fire protection system pfl gt units 17-20 (Site:fort lauderdale gt's) Total		0	36,050.16
	V=IMPROVE Total			2	337,563.10
2004 Total				3,300	530,380.61
2005	O=OPERATION	02690-070-0928-007 - replace 3b intake cooling pump/motor (Site:martin plant u3)	DRIVE, ELECTRIC MOTOR, COMPLETE	1	19,864.94
			PUMP COMPLETE	1	29,797.40
		02690-070-0928-007 - replace 3b intake cooling pump/motor (Site:martin plant u3) Total		2	49,662.34
		02966-070-0911-007 - replace 460sy discharge canal retaining wall (Site:ft myers plant)	DISCHARGE CANAL	0	103,614.00
		02966-070-0911-007 - replace 460sy discharge canal retaining wall (Site:ft myers plant) Total		0	103,614.00
	O=OPERATION Total			2	153,276.34
2005 Total				2	153,276.34
2006	H=HURRICANES/MAJO	03522-070-0921-007 - replace gt shop roof at pfl (Site:ft lauderdale gt's)	ROOF	2	244,339.34
		03522-070-0921-007 - replace gt shop roof at pfl (Site:ft lauderdale gt's) Total		2	244,339.34
	H=HURRICANES/MAJOR STORMS Total			2	244,339.34
	O=OPERATION	02757-070-0921-007 - pfl gt units 21-24 fire protection system repl (Site:fort lauderdale gts	SUPERSTRUCTURE	0	54,434.25
		02757-070-0921-007 - pfl gt units 21-24 fire protection system repl (Site:fort lauderdale gts) Total		0	54,434.25
		03257-070-0905-007 - replace ppn 2c acw pump motor (Site:putnam plant)	DRIVE, ELECTRIC MOTOR, COMPLETE	1	12,967.87
		03257-070-0905-007 - replace ppn 2c acw pump motor (Site:putnam plant) Total		1	12,967.87
		03593-070-0921-007 - pfl gt fire protection system replacement (Site:fort lauderdale gts)	SUPERSTRUCTURE	0	58,857.14
		03593-070-0921-007 - pfl gt fire protection system replacement (Site:fort lauderdale gts) Total		0	58,857.14
		04355-070-0908-007 - pfl waste water treatment pond liner replacement (Site:fort lauderdal	LINER, COMPLETE	1	54,872.62
		04355-070-0908-007 - pfl waste water treatment pond liner replacement (Site:fort lauderdale-common) Total		1	54,872.62
		04371-070-0908-007 - pfl wtp degasifier product pump/motor replacement (Site:fort lauderd	PUMP COMPLETE	1	30,630.40
		04371-070-0908-007 - pfl wtp degasifier product pump/motor replacement (Site:fort lauderdale-common) Total		1	30,630.40
		04375-070-0908-007 - pfl wt-5 sump pump/motor replacement (Site:fort lauderdale-common)	PUMP COMPLETE	1	1,003.00
		04375-070-0908-007 - pfl wt-5 sump pump/motor replacement (Site:fort lauderdale-common) Total		1	1,003.00
		04490-070-0905-007 - replace ppn service bldg a/c unit (Site:putnam plant)	AIR HANDLER	1	10,173.98
			CONDENSER/COMPRESSOR	1	7,630.50

Account 341.0
Retirements

Ledger Year	Reason	Work Order Number	Retirement Units	Quantity	Amount
2006	O=OPERATION	04490-070-0905-007 - replace ppn service bldg a/c unit (Site:putnam plant) Total		2	17,804.48
		04491-070-0905-007 - replace ppn control room bldg a/c unit (Site:putnam plant)	AIR HANDLER	1	5,248.06
			CONDENSER/COMPRESSOR	1	3,936.30
		04491-070-0905-007 - replace ppn control room bldg a/c unit (Site:putnam plant) Total		2	9,184.36
	O=OPERATION Total			8	239,754.12
2006 Total				10	484,093.46
2007	C=DETERIORATION/FA	05566-070-0908-007 - PFL - Replace the controller at water treatment plant	CONTROL/INSTRUMENTATION SYSTEM	0	4,643.00
		05566-070-0908-007 - PFL - Replace the controller at water treatment plant Total		0	4,643.00
		06029-070-0908-007 - Rewind 5B open cooling water pump motor	MOTOR STATIONARY WINDING ASSEMBLY	1	24,265.15
		06029-070-0908-007 - Rewind 5B open cooling water pump motor Total		1	24,265.15
	C=DETERIORATION/FAILURE Total			1	28,908.15
	O=OPERATION	02230-070-0908-007 - pfl wtp vacuum degasifier pump replacements (Site:fort lauderdale-c	PUMP COMPLETE	3	91,891.21
		02230-070-0908-007 - pfl wtp vacuum degasifier pump replacements (Site:fort lauderdale-common) Total		3	91,891.21
		04129-070-0908-007 - pfl control room bldg hvac coils replacement (Site:fort lauderdale-co	CONDENSER/COMPRESSOR	10	710,690.44
		04129-070-0908-007 - pfl control room bldg hvac coils replacement (Site:fort lauderdale-common) Total		10	710,690.44
		04630-070-0911-007 - replace 2 raw water wells at pfm (Site:ft myers plant common - 505)	RAW WATER WELL	2	130,103.92
		04630-070-0911-007 - replace 2 raw water wells at pfm (Site:ft myers plant common - 505) Total		2	130,103.92
		04975-070-0923-007 - ppe 3 gt bldg 1 fire protection sys replacement (Site:port everglades	FIRE PROTECTION SYS COMPLETE	1	95,439.90
		04975-070-0923-007 - ppe 3 gt bldg 1 fire protection sys replacement (Site:port everglades gts) Total		1	95,439.90
		05299-070-0905-007 - replace ppn service bldg a/c (Site:putnam plant)	CONDENSER/COMPRESSOR	1	3,815.25
		05299-070-0905-007 - replace ppn service bldg a/c (Site:putnam plant) Total		1	3,815.25
		05300-070-0905-007 - replace ppn shift shop bldg a/c (Site:putnam plant)	HVAC SYSTEM COMPLETE	0	5,658.16
		05300-070-0905-007 - replace ppn shift shop bldg a/c (Site:putnam plant) Total		0	5,658.16
		05405-070-0907-007 - psn common replace storeroom hvac condensing (Site:sanford plan	CONDENSER/COMPRESSOR	1	1,221.00
		05405-070-0907-007 - psn common replace storeroom hvac condensing (Site:sanford plant site common) Total		1	1,221.00
		05406-070-0907-007 - psn common replace battery room air handler (Site:sanford plant site	AIR HANDLER	1	10,694.11
		05406-070-0907-007 - psn common replace battery room air handler (Site:sanford plant site common) Total		1	10,694.11
	O=OPERATION Total			19	1,049,513.99
	V=IMPROVE	05754-070-0911-007 - PFM Combined Cycle Common Plant: Install Raw Water Well	RAW WATER WELL	2	39,740.81
		05754-070-0911-007 - PFM Combined Cycle Common Plant: Install Raw Water Well Total		2	39,740.81
	V=IMPROVE Total			2	39,740.81
2007 Total				22	1,118,162.95
Grand Total				3,334	2,285,913.36

Q.

Net Salvage. Please provide a detailed categorization of the investment within each account or subaccount as of December 31, 2007. The information should be provided in both hard copy and on electronic medium in Excel or Lotus readable format.

A.

FPL interprets the term "investment" in this interrogatory to mean plant in-service balance and has answered in this regard. See attachments provided in FPL's response to Depreciation - OPC's First Set of Interrogatories No. 3, and FPL's response to Depreciation - OPC's First Request for Production of Documents No. 13 "FPL 2008 Service Life File.xls."

Q.

Net Salvage. Please provide a detailed categorization of the retirements by account, by year for the past 10 years into the greatest level of detail available along with the corresponding dollar amounts. The information should be provided in both hard copy and on electronic medium in Excel or Lotus readable format.

A.

See attachments provided in FPL's response to Depreciation - OPC's First Set of Interrogatories No. 3, and FPL's response to Depreciation - OPC's First Request for Production of Documents No. 13 "FPL 2008 Service Life File.xls."

Account 344.0
Retirements

Ledger Year	Reason Code	Work Order Number	Retirement Units	Quantity	Amount
2003	A=SYSTEM UPGRADE/N	07500-070-0009-006 - retirement corrections #4 found during prs/cpr exa(Site	WEDGE SYSTEM	(1)	(67,238.10)
		07500-070-0009-006 - retirement corrections #4 found during prs/cpr exa(Site:property accounting) Total		(1)	(67,238.10)
	A=SYSTEM UPGRADE/NEW SYSTEM Total			(1)	(67,238.10)
	O=OPERATION	01025-070-0905-007 - ppn 2gt2 generator rewedge (Site:putnam plant)	WEDGE SYSTEM	1	67,238.10
		01025-070-0905-007 - ppn 2gt2 generator rewedge (Site:putnam plant) Total		1	67,238.10
		01026-070-0905-007 - ppn2 steam turbine generator rewedge (Site:putnam pl	WEDGE SYSTEM	1	67,238.10
		01026-070-0905-007 - ppn2 steam turbine generator rewedge (Site:putnam plant) Total		1	67,238.10
		01171-070-0921-007 - replace rotor coils at pfl gt 7 (Site:pfl gt)	ROTOR	0	44,839.57
		01171-070-0921-007 - replace rotor coils at pfl gt 7 (Site:pfl gt) Total		0	44,839.57
		09710-070-0916-006 - generator stator rewind psn4 (Site:sanford plant)	STATOR	0	729,661.26
		09710-070-0916-006 - generator stator rewind psn4 (Site:sanford plant) Total		0	729,661.26
	O=OPERATION Total			2	908,977.03
	V=IMPROVE	08825-070-0909-006 - pfm repowering outage-u2 generator rewedge (Site:for	STATOR	0	63,311.73
		08825-070-0909-006 - pfm repowering outage-u2 generator rewedge (Site:fort myers plant) Total		0	63,311.73
		08908-070-0916-006 - psn repowering-replace unit 4 exciter (Site:sanford pla	CONTROL/INSTRUMENTATION SYSTEM	2	46,049.50
			ENCLOSURE	1	24,392.73
			HEAT EXCHANGER, SHELL	2	3,181.66
			HEATING SYSTEM	1	3,181.66
			ROTOR (MAIN EXCITER)	1	132,829.09
			ROTOR (PILOT EXCITER)	1	5,302.76
			STATOR (MAIN EXCITER)	1	21,211.07
			STATOR (PILOT EXCITER)	1	3,181.66
		08908-070-0916-006 - psn repowering-replace unit 4 exciter (Site:sanford plant) Total		10	239,330.13
		09172-070-0916-006 - psn4 repowering-plant refurbishment (Site:sanford plar	GENERATOR COOLING AND PURGE EQUIPMENT	1	186,141.30
		09172-070-0916-006 - psn4 repowering-plant refurbishment (Site:sanford plant) Total		1	186,141.30
	V=IMPROVE Total			11	488,783.16
2003 Total				12	1,330,522.09
2004	O=OPERATION	01345-070-0921-007 - replace rotor coils & pfl gt2 (Site:pfl gt)	ROTOR	0	44,839.57
		01345-070-0921-007 - replace rotor coils & pfl gt2 (Site:pfl gt) Total		0	44,839.57
		01619-070-0908-007 - pfl unit 4 generator stator rewind (Site:fort lauderdale u	STATOR	3	336,195.68
		01619-070-0908-007 - pfl unit 4 generator stator rewind (Site:fort lauderdale unit 4) Total		3	336,195.68
		01674-070-0923-007 - replace rotor coils (Site:port everglades gt)	ROTOR COILS	1	70,939.34
		01674-070-0923-007 - replace rotor coils (Site:port everglades gt) Total		1	70,939.34
		01775-070-0908-007 - 4b ct generator rewedge (Site:lauderdale unit 4b ct)	WEDGE SYSTEM	1	102,752.29
		01775-070-0908-007 - 4b ct generator rewedge (Site:lauderdale unit 4b ct) Total		1	102,752.29
		01776-070-0908-007 - 4a ct generator rewedge (Site:lauderdale unit 4a ct)	WEDGE SYSTEM	1	102,752.29
		01776-070-0908-007 - 4a ct generator rewedge (Site:lauderdale unit 4a ct) Total		1	102,752.29
		02116-070-0923-007 - ppe gt unit 3 rotor coil replacement (Site:port everglade	ROTOR COILS	1	70,939.34
		02116-070-0923-007 - ppe gt unit 3 rotor coil replacement (Site:port everglades gt) Total		1	70,939.34
		02121-070-0905-007 - replace ppn 1gt2 exciter rotor coil (Site:putnam plant)	ROTOR COILS	1	33,024.06
		02121-070-0905-007 - replace ppn 1gt2 exciter rotor coil (Site:putnam plant) Total		1	33,024.06
		02229-070-0922-007 - pfm gt #9 generator rewedge (Site:ft myers power plan	ROTOR	1	328,913.43

Account 344.0
Retirements

Ledger Year	Reason Code	Work Order Number	Retirement Units	Quantity	Amount
2004	O=OPERATION	02229-070-0922-007 - pfm gt #9 generator rewedge (Site:ft myers power plan	STATOR	0	8,228.80
		02229-070-0922-007 - pfm gt #9 generator rewedge (Site:ft myers power plant) Total		1	337,142.23
	O=OPERATION Total			9	1,098,584.80
2004 Total				9	1,098,584.80
2005	O=OPERATION	02520-070-0922-007 - replace wedge system gt 1 (Site:ft myers gt's u1)	ROTOR	1	328,913.43
			STATOR	0	8,228.80
		02520-070-0922-007 - replace wedge system gt 1 (Site:ft myers gt's u1) Total		1	337,142.23
		02758-070-0921-007 - pfl gt unit 2-19 generator rotor coils replacement(Site:fo	ROTOR COILS	1	86,228.28
		02758-070-0921-007 - pfl gt unit 2-19 generator rotor coils replacement(Site:fort lauderdale gts) Total		1	86,228.28
		02800-070-0923-007 - ppe gt unit 3-11 generator rotor coils replacement(Site:	ROTOR COILS	1	70,939.34
		02800-070-0923-007 - ppe gt unit 3-11 generator rotor coils replacement(Site:port everglades gts) Total		1	70,939.34
		02956-070-0905-007 - replace 2gt2 exciter rotor (Site:putnam plant)	ROTOR (MAIN EXCITER)	1	33,024.06
		02956-070-0905-007 - replace 2gt2 exciter rotor (Site:putnam plant) Total		1	33,024.06
	O=OPERATION Total			4	527,333.91
2005 Total				4	527,333.91
2006	O=OPERATION	02807-070-0908-007 - pfl unit 5 generator stator rewind (Site:fort lauderdale u	STATOR	3	244,923.39
		02807-070-0908-007 - pfl unit 5 generator stator rewind (Site:fort lauderdale unit 5) Total		3	244,923.39
		03632-070-0905-007 - replace ppn 1gt1 exciter rotor (Site:putnam plant)	ROTOR (MAIN EXCITER)	1	33,024.06
		03632-070-0905-007 - replace ppn 1gt1 exciter rotor (Site:putnam plant) Total		1	33,024.06
		03663-070-0905-007 - replace ppn 1gt1 gen wedge system (Site:putnam plan	WEDGE SYSTEM	1	57,539.00
		03663-070-0905-007 - replace ppn 1gt1 gen wedge system (Site:putnam plant) Total		1	57,539.00
		03975-070-0922-007 - replace wedge system gt 8 (Site:ft myers gt's u8)	STATOR	0	8,228.80
		03975-070-0922-007 - replace wedge system gt 8 (Site:ft myers gt's u8) Total		0	8,228.80
		04025-070-0905-007 - replace ppn 1 s.t. exciter rotor (Site:putnam plant)	ROTOR (MAIN EXCITER)	1	33,024.06
		04025-070-0905-007 - replace ppn 1 s.t. exciter rotor (Site:putnam plant) Total		1	33,024.06
		04029-070-0905-007 - replace ppn 1gt2 gen wedge system (Site:putnam plan	WEDGE SYSTEM	1	57,539.00
		04029-070-0905-007 - replace ppn 1gt2 gen wedge system (Site:putnam plant) Total		1	57,539.00
		04291-070-0928-007 - replace pmg3 s.t.gen wedge system (Site:martin unit 3)	WEDGE SYSTEM	0	263,946.56
		04291-070-0928-007 - replace pmg3 s.t.gen wedge system (Site:martin unit 3) Total		0	263,946.56
		04292-070-0928-007 - replace pmg3a gen wedge system (Site:martin-unit 3)	WEDGE SYSTEM	0	135,192.14
		04292-070-0928-007 - replace pmg3a gen wedge system (Site:martin-unit 3) Total		0	135,192.14
		04293-070-0928-007 - replace pmg3b gen wedge system (Site:martin-unit 3)	WEDGE SYSTEM	0	135,192.14
		04293-070-0928-007 - replace pmg3b gen wedge system (Site:martin-unit 3) Total		0	135,192.14
	O=OPERATION Total			7	968,609.15
	V=IMPROVE	04260-070-0922-007 - replace gt 9 rotor (Site:ft myers gt)	ROTOR	1	365,459.37
			STATOR	0	8,228.80
		04260-070-0922-007 - replace gt 9 rotor (Site:ft myers gt) Total		1	373,688.17
	V=IMPROVE Total			1	373,688.17
2006 Total				8	1,342,297.32
Grand Total				33	4,298,738.12

Q.
Decommissioning. For each activity envisioned in the decommissioning process, please provide the following:

a. A detailed narrative identifying the activity;

b. All support and justification for the crew mix; and

c. A complete demonstration that the crew mix is the same crew mix reflected in the productivity factors obtained from the engineering consulting firm. To the extent they are not, indentify the differences.

A.
FPL assumes that "decommissioning" as used in this interrogatory refers to fossil dismantlement, as the decommissioning of nuclear units is not the subject of this docket.

a. The activities envisioned by FPL's fossil dismantlement study include:

Remove loose equipment, furniture, etc.
Remove oil tanks:
Evacuate pumpable product to adjacent tank and drop level of products below the shell manhole;
Remove the manhole lid and evacuate the pumpable product through the manhole to the adjacent tank;
Dilute the sludge and draw the solid and liquid waste off the tank;
Dispose the wastes to the designated land fill;
Clean up the tank and obtain the Gas Free Certification;
Dismantle tank.
Remove all insulation and covering and transport to acceptable landfill.
For asbestos insulation:
Set up enclosures and establish negative air pressure;
Seal around enclosure penetrations;
Identify and mark travel paths for egress and ingress;
Set up decontamination unit - determine where water will discharge to;
Disposal - Determine holding area and isolate route or travel for others;
Monitor air and personnel;
Run clearance for final air test;
Tear down enclosures and decontamination units and demobilize.

Collapse circulating water lines and back fill trenches.
Remove intake and discharge structures, set up silt boom and haul fill.
Remove equipment pumps, piping and valves.
Remove lube oil pumps, all piping and instrument and electrical systems.
Remove forced draft and induced draft fans with ductwork, and air heaters.
Remove burners, upper and lower headers, manways, waterwalls.
Remove heavy steel structures and above-ground steel.
Disassemble crane, boiler feed pumps and turbine generator.
Separate scrap metals and remove to scrap yard.
Remove and dispose of miscellaneous rubble.
Remove turbine pedestal, foundation and heavy concrete structures and buildings.
Remove stack foundations, equipment foundations, substructures, support buildings and stacks. Transport to landfill.
Cut off piles and remove pile caps.
Remove concrete encased duct banks and underground piping.
Remove any underground storage tanks.
Install any environmental monitoring equipment at wells, etc.
Remove or improve remaining site facilities - buildings, fences, parking areas in accordance with local code and regulations.
Remove solid and liquid wastes from waste treatment processing areas - precipitated material in ponds and tanks, contaminated resins and reactants.
Provide for erosion control by site grading, seeding and mulching.

b. The crew mix used in FPL's fossil dismantlement study was provided by FPL's engineers at the time the dismantlement study methodology was first developed in 1990 and is consistent with crew mixes used in fossil dismantlement studies done by or for other U.S. utilities that were reviewed at that time. The crew mix is typical for a demolition project.

c. The only difference between the crew mix used for the Cutler and Port Everglades decommissioning studies that were reviewed by NUS is that the Port Everglades study used a crew mix that included two heavy equipment operators whereas the Cutler study used a crew mix that included only one. This difference was not deemed by NUS as requiring different productivity factors.

   Over time, through continued consultation with its engineers, FPL settled on the crew mix used in the current dismantlement filing: six journeyman laborers, one equipment operator, and one foreman. Because this crew mix was included in NUS's review, FPL believes that it is consistent with the productivity factors employed.

Q.

Transmission Plant Easements Account 350.2. Please state if FPL plans to continue utilizing transmission easements as it replaces transmission investment that sits on the easement. If not, specifically state how FPL plans to provide transmission service, as well as the reason why any alternative is more appropriate than continued usage of the existing easements.

A.

FPL plans to continue utilizing transmission easements as it replaces transmission investment that currently occupies the easement.

Q.

Transmission Plant Easements Account 350.2. Please identify each easement along with the corresponding dollar level of investment that has a specific expiration date. Further, identify when each easement was first obtained and the corresponding expiration date.

A.

FPL's policy is to obtain perpetual rights easements (no expiration) everywhere that is available. Exceptions may include sovereign lands, government lands, and instances where only temporary rights are needed for construction purposes.

Attachment No. 1 includes easements with investment in Account 350.2, for which there is an expiration date. Attachment No. 1 is confidential and the unredacted document will be made available by FPL for inspection and review by OPC at Rutledge, Ecenia & Purnell, P.A., 119 South Monroe Street, Suite 202, Tallahassee, Florida, during regular business hours, 8 a.m. to 5 p.m., Monday through Friday, upon reasonable notice to FPL's counsel.

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of NEVADA POWER COMPANY for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.	Docket No. 06-11022
Application of NEVADA POWER COMPANY for approval of new and revised depreciation and amortization rates.	Docket No. 06-11023

ORDER

The Public Utilities Commission of Nevada ("Commission") makes the following findings and conclusions:

I. Procedural History

1. On November 17, 2006, Nevada Power Company ("NPC") filed with the Public Utilities Commission of Nevada ("Commission") an Application, designated as Docket No. 06-11022, for authority to increase its general rates to all classes of electric customers to reflect an increase in its annual revenue requirement for general rates and for relief properly related thereto. NPC requests an increase in annual revenues of $172.4 million, which is approximately an 8% increase over present revenues. The impact of the Application varies by customer rate class. The proposed average impact for all residential customer classes is 12.25%.

2. Also on November 17, 2006, NPC filed with the Commission an Application, designated as Docket No. 06-11023, for approval of new and revised depreciation and amortization rates for electric operations. Specifically, the Application requests an increase to current annual depreciation and amortization expenses of approximately $54 million. In Docket No. 03-10002, NPC sought and was granted a delay in implementing revised depreciation rates. As such, current effective depreciation rates were last set in 1991.

Commission Discussion and Findings

415. The Commission concurs that recovery of the 2% net profit franchise fee in general rates would reduce administrative burden and provide the ratepayer with some level of increased rate stability. However, as noted by Staff, the 2% net profit franchise fee amount is insufficient to warrant specialized ratemaking treatment. Therefore, the Commission finds that NPC's request to recover the 2% net profit franchise fee in general rates as modified by Staff is approved.

IV. Depreciation Study

NPC's Position

416. C. Richard Clarke, Director of Western U.S. Services for the Valuation and Rate Division of Gannett Fleming, prepared and sponsored NPC's depreciation study ("Depreciation Study"). Except for production plant, the Depreciation Study utilizes plant in service as of the last date of the previous full calendar year, December 31, 2005. (Exhibit 36 at 4.) Three production plants were placed into service after December 31, 2005. The plants include the Lenzie Units 1 and 2 and the Harry Allen Unit 4. These units are considered part of the Depreciation Study using plant balances as of June 30, 2006. (Id. at 13.) Also, the current Depreciation Study includes a modeling modification when compared to previous studies. The Depreciation Study reflects individual depreciation rates for each generation plant, whereas prior studies' rates were developed at the FERC account level as mass assets. (Id. at 12.)

417. Mr. Clarke used the straight line remaining life method of depreciation, with the average service life procedure.

418. Annual depreciation was calculated using a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of units or assets, in a systematic and rational manner. (Id. at 6.) NPC's recommended annual depreciation accrual rates were determined in two phases. In the first phase,

(2) NPC's failure to recognize economies of scale when determining that the demolition costs per kilowatt derived from an approximate 50 MW unit are applicable to 600 MW units; and (3) unreasonable results reflected in NPC's presentation for production plant, including a failure to recognize that electric generating plants can and will be sold in the future. Until NPC can present a thorough, complete and well-documented analysis that takes into account all realistic possibilities associated with retirements of existing generation, it should not be allowed to arbitrarily increase revenue requirements through production plant net salvage proposals. The BCP's recommendation will result in a reduction of $23.2 million for plant as of December 31, 2005. (Id. at 32-34.)

456. The BCP, however, also provided an alternative recommendation. If the Commission is prepared to recognize the possibility that electric generating units can and will be sold sometime in the future, the BCP recommended a 10% positive level of net salvage for all generating units. (Id. at 34-35.)

457. With regard to mass property life analysis, the BCP recommended adjustments to three accounts, including Account 353 – Transmission Station Equipment, Account 366 – Distribution Underground Conductors, and Account 367 – Distribution Underground Conductors and Devices. (Id. at 36-37.)

458. For Account 353, NPC proposed to increase the ASL from 45 years to 50 years while retaining the R2 Iowa Survivor Curve. NPC's proposal for this account is unreasonable because NPC's analyses do not reasonably match the historical retirement pattern with its proposed life/curve combination. NPC simply assumed without basis that the most significant retirement reflected in its historical analysis was normal. As such, NPC's proposal failed to properly recognize the relationship of the investment in this account to the type of plant retired during the past 10 years. In the alternative, the BCP recommended use of a 60 S0.5 life/curve combination, stating that its values were conservative and in line with NPC's own recognition that a longer life expectancy is

Q.

Station Equipment – Step Up Transformers. Please provide a detailed narrative identifying what retired and why the retirement occurred at age zero for Account 353.1 – Station Equipment – Step Up Transformers, as set forth on Exhibit CRC-1, page 506. Further, specifically state why this event is considered representative of the remaining investment.

A.

The retirement of $3,449,428 occurred as a result of failure of a generator step up transformer at the Turkey Point Nuclear plant in June 2005. The replacement work order is 0006-009-0831.

The information for this year as well as all years 1958 through 2007 were provided by the Company for the life analysis. No specific year was analyzed for FPL's depreciation study, but rather all years and bands of years were used. For this account if the retirement at age zero of $3,449,428 were deemed to be atypical and excluded from the analysis there would be no impact on the chosen curve and life. The 33 R2 life and curve is still the best fit and is representative of this account. The information derived from examining all years and bands was used to determine estimated curve and average service life. The resulting estimate therefore represents the best information available at the time for this account. Because the estimate is based on 50 years of actual history, we believe that it is indicative of future conditions until new recorded information is available and that unusual events occurring in any one particular year do not affect the results significantly or inappropriately.

Q.

Transmission Towers & Fixtures. Please explain why FPL decreased the average service life from 45 years to 40 years for Account 354 – Transmission Towers & Fixtures, as set forth on Exhibit CRC – 1, page 510. The response should specifically address references made to the industry data suggesting a 40 to 70-year average service life and why FPL thought that it was appropriate to move to the lowest level of the identified industry range. The response should include a step by step analysis identifying each factor and how each factor interacted with other factors that were employed to arrive at the proposed 40-year average service life.

A.

Account 354 Towers and Fixtures should have a 45-R5 curve and life. There was not enough data to perform a complete life analysis and therefore the curve and life were left unchanged from the current approved. The information in the Depreciation Report (Exhibit CRC-1) that discusses the change to a 40-R5 life and curve is incorrect and should be changed. The Depreciation Report and associated work papers will be revised to reflect the 45-R5 life and curve. The impact of this revision would be approximately $1.5 million decrease in annual depreciation expense.

ACCOUNT 356: OVERHEAD CONDUCTORS & DEVICES

This account includes the cost of overhead conductors and devices on tower lines used for electric transmission.

This account includes:
Airbreak switch
Circuit breaker
Conductor
Disconnect
Switch insulator
Lightening arrestor
Line switch

SERVICE LIFE:

This account currently has a 50 R4 curve and life. There are retirements on an annual basis however they are small in comparison to the total account. There is not much that affects the life of conductor and according to Company personnel the life is over 50 years. A statistical analysis was performed but the results were meaningless due to the small retirements. Industry has lives in the 38-65 year range [redacted] curves are in the higher mid range R family. We will increase the life slightly to reflect company information and the industry, use a 55 R4.

SALVAGE:

Currently the net salvage is (25). There was no retirement data that was meaningful for a salvage analysis. The industry range is (5)-(80) with a trend to more negative. We have nothing to suggest change so we will retain the (25) net salvage percent.

02-05-004

SOUTHERN CALIFORNIA
EDISON®

An *EDISON INTERNATIONAL®* Company

(U 338-E)

2003 General Rate Case

Workpapers

SCE-8: Results of Operations
Chapter XI

Southern California Edison Company
Simulated Plant Record - Balances Method
Account : 359.000 ROADS AND TRAILS

Approved Curve: SQ - 60

Account Activity (as a percentage of the 2000 balance)

1. 5 Year Additions: 2,159,100 / 23,101,960 = 9.35%

2. 5 Year Retirements: 22,570 / 23,101,960 = 0.10%

3. 1995 Balance: 20,965,430 / 23,101,960 = 90.75%

Balance as a % of 2000 Balance	
3 years ago	100.00%
5 years ago	90.75%
7 years ago	90.36%
10 years ago	90.21%
15 years ago	55.48%

Trends in Data:

Very little activity, mostly additions.

A significant portion of the plant is new and added within the last 15 years.

Poor statistics -- Conformance Indices high, but insufficient retirement experience.

SELECTION: SQ - 60

Comments:

Industry average 60 years and SQ curve most predominant. Currently approved is 60 years and SQ curve. Continue to use the approved SQ-60.

Ex 35

NEVADA POWER COMPANY

BEFORE THE

PUBLIC UTILITIES COMMISSION OF NEVADA

IN THE MATTER of the Application of NEVADA POWER COMPANY for Approval of New and Revised Depreciation Rates	)	Docket No. 06-11 023

Depreciation Study

Application

Testimony

Depreciation Study

Eric Witkoski (5 Copies)
Bureau of Consumer Protection
555 E. Washington Street
Suite 3900
Las Vegas, NV 89101

352	Structures & Improvements	50	R3	-10	2.05	34,835	50	R3	-10	2.16	37,669	2,834
353	Station Equipment	45	R2	5	2.03	8,380,929	50	R2	5	1.82	7,763,620	-617,309
354	Towers & Fixtures	45	R3	-25	2.88	381,791	60	R4	-25	1.72	241,115	-140,676
355	Poles & fixtures	38	R1.5	-20	3.08	5,922,832	45	R1.5	-20	2.44	4,790,262	-1,132,570
356	*Overhead Conductors & Devices*	40	R3	-10	2.86	3,112,508	50	R1.5	-10	1.97	2,206,893	-905,615
357	Underground Conduit				2.41	161,179	50	R2	0	1.88	125,501	-35,678
358	Underground Conductors				2.40	224,077	35	R3	0	2.91	271,614	47,537
359	Roads & Trails	65	R5	0	1.65	28,670	60	R5	0	1.76	30,597	1,927
	TOTAL TRANSMISSION PLANT					19,020,048					16,353,811	-2,666,237
	DISTRIBUTION PLANT											
360.2	Land Rights	65	S5	0	1.59	417,489	65	R4	0	1.54	413,492	-3,997
361	Structures & Improvements	42	S1	-5	2.26	8,808	50	R3	-5	2.14	13,773	4,965
362	Station euipment	37	R2	-10	2.98	10,391,873	50	R1.5	-10	1.92	6,980,327	-3,411,546
364	Poles,Towers & Fixtures	45	R1	-25	2.20	1,241,644	50	R1.5	-25	2.39	1,363,159	121,515
365	Overhead Conductors	45	R1	5	1.85	1,556,227	50	R1	5	1.69	1,431,967	-124,260
366	Underground Conduit	50	R2	-20	2.41	3,435,019	50	R3	-20	2.36	3,366,506	-68,513
367	Underground Conductors	35	R3	15	2.40	16,983,785	35	S4	15	2.48	18,490,424	1,506,639
368	*Line transformers*	42	S0.0	5	2.13	6,675,135	38	R2.5	5	2.72	8,927,307	2,252,172
369	Services	30	S4	-50	5.40	8,278,995	40	R4	-50	3.39	5,413,702	-2,865,293
370	Meters	30	R1	1	3.43	2,414,265	35	R1	1	2.62	1,910,765	-503,500
372	*Leased Property on Customer Pemises*	15	S0.0	60	0.99	19,876	25	R1	60	1.06	21,451	1,575
373	Street Lighting	20	R1	0	3.15	35,142	25	R1	0	1.30	14,714	-20,428
												0
	TOTAL DISTRIBUTION PLANT					51,458,258					48,347,587	-3,110,671
	GENERAL PLANT											
3892	Rights of Way	40	R5	0	3.33	186	50	SQ	0	1.11	62	
390	Structures & Improvements	40	R4	-5	2.62	1,128,646	45	R2	-5	2.11	909,417	
391.1	Office Furniture & Euipment	23	L1	5	4.24	688,908	20	SQ	0	5.00	873,901	
391.2	Computers	7	L1	3	21.58	8,495,144	5	SQ	0	20.00	7,874,949	
392	Transportation Equipment	11	S1	20	7.81	1,230,277			10	10.28	1,630,492	
393	Store Equipment	20	R4	7	4.95	42,508	20	SQ	0	5.00	42,893	
394	Tools, Shop & Garage Euipment	35	S0.0	0	2.59	86,659	25	SQ	0	4.00	141,753	
395	Laboratory Equipment	30	R3	5	3.53	161,371	15	SQ	0	6.67	303,918	
396	Power-Operated Equipment	16	S2	15	4.08	790,038			10	8.20	1,595,845	
397	Communication Equipment	22	S2	-10	4.90	3,615,970	15	SQ	0	6.67	5,205,135	
398	Miscellaneous Equipment	20	L0.0	0	7.00	9,058	15	SQ	0	6.67	8,622	
	TOTAL GENERAL PLANT					16,248,765					18,586,987	2,338,222
	TOTAL PLANT					126,066,603					167,101,413	41,034,810

SIERRA PACIFIC POWER COMPANY

ELECTRIC DEPARTMENT

BEFORE THE

PUBLIC UTILITIES COMMISSION OF NEVADA

IN THE MATTER of the Application of SIERRA PACIFIC POWER COMPANY for Approval of New and Revised Depreciation Rates for its Electric Operations	)	Docket No. 05-10006

Depreciation Study

Application

Testimony

Depreciation Study

Eric Witkoski (5 Copies)
Bureau of Consumer Protection
555 E. Washington Street
Suite 3900
Las Vegas, NV 89101

SIERRA PACIFIC POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2004

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
ELECTRIC PLANT									
	INTANGIBLE PLANT								
303.00	MISCELLANEOUS INTANGIBLE PLANT	10-SQ	0	9,094,596.00	4,707,100	4,387,496	438;750	10.00	-
	STEAM PRODUCTION								
310.00	LAND RIGHTS	75-R3	0	203,037.21	142,587	60,449	1,081	0.53	55.9
311.00	STRUCTURES AND IMPROVEMENTS	125-R2	* (50)	66,660,470.15	41,097,654	58,893,051	2,439,398	3.66	24.1
312.00	BOILER PLANT EQUIPMENT	60-R2	* (50)	214,029,228.69	124,210,908	196,832,939	8,595,393	4.02	22.9
314.00	TURBOGENERATOR UNITS	70-R2	* (50)	72,139,455.52	45,995,070	62,214,117	3,126,234	4.33	19.9
315.00	ACCESSORY ELECTRIC EQUIPMENT	60-S1.5	* (50)	40,534,330.28	25,833,841	34,967,850	1,580,077	3.90	22.1
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	50-R1.5	* (50)	9,610,650.54	4,516,730	9,899,242	539,579	5.61	18.3
	TOTAL STEAM PRODUCTION			403,177,172.39	241,796,790	362,867,448	16,281,762	4.04	
	HYDRAULIC PRODUCTION								
330.20	LAND RIGHTS	120-S4	* 0	246,137.44	230,107	16,030	2,011	0.82	8.0
331.00	STRUCTURES & IMPROVEMENTS	100-S1	* (2)	1,894,709.69	1,016,424	916,182	114,773	6.06	8.0
332.00	RESERVOIRS, DAMS & WATERWAYS	70-R1	* (2)	14,167,066.51	11,146,313	3,304,096	421,945	2.98	7.8
333.00	WATERWHEELS, TURBINES & GENERATORS	65-R1.5	* (2)	716,232.62	642,706	87,851	11,183	1.56	7.9
334.00	ACCESSORY ELECTRIC EQUIPMENT	55-S3	* (2)	780,980.13	480,521	316,077	40,908	5.24	7.7
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	50-S2.5	* (2)	3,238.15	3,238	66	9	0.28	7.3
336.00	ROADS, RAILROADS & BRIDGES	55-R3	* (2)	180,580.01	102,791	81,381	10,733	5.94	7.6
	TOTAL HYDRAULIC PRODUCTION			17,988,924.55	13,622,100	4,721,683	601,562	3.34	
	OTHER PRODUCTION								
341.00	STRUCTURES & IMPROVEMENTS	SQUARE	* (10)	6,228,018.75	1,968,014	4,882,807	256,358	4.12	19.0
342.00	FUEL HOLDERS, PRODUCERS & ACCESSORY EQUIPMEI	SQUARE	* (10)	13,864,751.88	3,549,368	11,701,859	575,246	4.15	20.3
343.00	PRIME MOVERS	SQUARE	* (10)	23,270,436.91	6,729,516	18,867,964	942,145	4.05	20.0
344.00	GENERATORS	SQUARE	* (10)	42,116,393.30	16,436,518	29,893,717	1,569,253	3.73	19.0
345.00	ACCESSORY ELECTRIC EQUIPMENT	SQUARE	* (10)	39,608,609.14	13,122,497	30,446,969	1,480,576	3.74	20.6
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	SQUARE	* (10)	8,706,553.87	1,378,798	8,198,410	397,922	4.57	20.6
	TOTAL OTHER PRODUCTION			133,796,763.85	43,184,711	103,991,726	5,221,500	3.90	
	TRANSMISSION PLANT								
350.20	LAND RIGHTS	70-R4	0	41,937,662.27	3,854,255	38,083,404	594,873	1.42	64.0
352.00	STRUCTURES & IMPROVEMENTS	55-R4	(5)	6,745,425.61	1,276,137	5,806,558	133,239	1.98	43.6
353.00	STATION EQUIPMENT	50-R3	(10)	156,143,175.40	53,006,094	118,751,399	3,011,527	1.93	39.4
354.00	TOWERS & FIXTURES	60-R4	(10)	126,751,388.60	22,333,188	119,293,340	2,266,469	1.76	52.1
355.00	POLES AND FIXTURES	60-R3	(30)	54,056,038.72	19,121,864	51,151,166	1,093,447	2.02	46.8
356.00	OVERHEAD CONDUCTORS AND DEVICES	55-R4	(25)	112,752,999.84	39,165,350	101,775,901	2,280,303	2.02	44.6
357.00	UNDERGROUND CONDUIT	60-S4	(10)	6,967,583.86	840,972	6,823,371	133,927	1.92	50.9
358.00	UNDERGROUND CONDUCTORS AND DEVICES	50-S3	(15)	10,876,916.77	937,307	11,571,147	255,427	2.35	45.3
359.00	ROADS AND TRAILS	70-R4	0	399,232.10	218,481	180,751	4,766	1.19	37.9
	TOTAL TRANSMISSION PLANT			518,630,423.17	140,753,468	453,437,037	9,795,978	1.89	

Ex E27

SIERRA PACIFIC POWER COMPANY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED
ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2004

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	DISTRIBUTION PLANT								
360.20	LAND RIGHTS	65-R4	0	6,981,933.91	2,295,835	4,666,097	104,322	1.50	44.7
361.00	STRUCTURES & IMPROVEMENTS	55-R3	(5)	1,646,448.17	617,035	1,113,834	30,081	1.82	37.1
362.00	STATION EQUIPMENT	50-R4	(10)	143,461,643.05	49,971,616	107,836,191	2,882,595	2.01	37.4
364.00	POLES, TOWERS AND FIXTURES	45-R0.5	(15)	142,694,449.20	63,939,358	100,159,261	2,683,859	1.88	37.3
365.00	OVERHEAD CONDUCTORS AND DEVICES	55-R2.5	(50)	129,044,802.84	67,674,025	125,893,180	3,152,036	2.44	39.9
366.00	UNDERGROUND CONDUIT	60-S2	(10)	79,108,853.22	24,559,649	60,460,090	1,345,877	1.70	44.9
367.00	UNDERGROUND CONDUCTORS AND DEVICES	50-S2.5	(40)	226,648,092.39	75,086,211	242,221,116	5,995,491	2.65	40.4
368.00	LINE TRANSFORMERS	45-R0.5	(15)	145,500,318.90	55,189,464	112,135,914	2,991,133	2.06	37.5
369.00	SERVICES	40-R2	(60)	102,624,268.47	52,021,200	112,177,664	3,645,802	3.55	30.8
370.00	METERS	33-R1.5	0	39,747,866.21	14,700,648	25,047,214	1,016,738	2.56	24.6
371.00	INSTALLATIONS ON CUSTOMERS PREMISES	25-R2.5	(40)	8,470,251.21	7,005,012	4,853,342	449,983	5.31	10.8
373.00	STREET LIGHTING AND SIGNAL SYSTEM	35-R2	(20)	26,836,735.24	8,276,743	23,925,337	964,732	3.59	24.8
	TOTAL DISTRIBUTION PLANT			1,052,747,682.81	421,338,786	920,489,249	25,262,629	2.40	
	GENERAL PLANT								
390.00	STRUCTURES & IMPROVEMENTS	45-R2.5	(5)	9,042,940.21	2,491,579	7,003,508	229,447	2.54	30.5
391.10	OFFICE FURNITURE AND EQUIPMENT	20-SQ	0	2,011,465.27	1,188,515	822,951	100,573	5.00 **	-
391.20	COMPUTER EQUIPMENT	5-SQ	0	3,390,680.08	1,891,680	1,699,000	678,136	20.00 **	-
391.30	COMPUTER EQUIPMENT - ESCC	10-SQ	0	2,911,537.03	2,028,519	883,019	291,154	10.00 **	-
392.00	TRANSPORTATION EQUIPMENT		10	20,717,069.00	6,519,265	14,197,804	2,956,326	14.27 ***	-
393.00	STORES EQUIPMENT	20-SQ	0	214,101.68	129,496	84,606	10,705	5.00 **	-
394.00	TOOLS, SHOP & GARAGE EQUIPMENT	25-SQ	0	4,000,737.49	2,181,759	1,818,980	160,029	4.00 **	-
395.00	LABORATORY EQUIPMENT	15-SQ	0	754,690.50	309,708	444,983	50,336	6.67 **	-
396.00	POWER OPERATED EQUIPMENT		10	4,755,149.00	638,842	4,116,307	456,019	9.59 ***	-
397.00	COMMUNICATION EQUIPMENT	15-SQ	0	24,518,317.36	7,598,567	16,919,747	1,635,372	6.67 **	-
	TOTAL GENERAL PLANT			72,316,687.62	24,777,930	47,990,905	6,565,099	9.08	
	NONDEPRECIABLE PLANT								
301.00	ORGANIZATION			25,156.00					
302.00	FRANCHISES AND CONSENTS			5,851.00					
310.00	LAND			925,442.00					
330.00	LAND			108,604.00					
340.00	LAND			208,294.00					
350.00	LAND			1,036,266.00					
360.00	LAND			2,332,478.00					
389.00	LAND			1,412,885.00					
	TOTAL NONDEPRECIABLE			6,055,176.00					
	TOTAL ELECTRIC PLANT IN SERVICE			2,213,807,426.39	890,180,885	1,897,885,535	68,119,028		

ONCOR ELECTRIC DELIVERY
EXISTING AND PROPOSED LIFE PARAMETERS
FOR TRANSMISSION, DISTRIBUTION, AND GENERAL FUNCTIONS
AT DECEMBER 31, 2007

Account No.	Description	Existing Life	Proposed Life	Change
Transmission				
350	Land and Land Rights	70 R3	70 R3	0
352	Structures and Improvements	41 R4	48 S6	7
353	Station Equipment	45 R2	46 L0.5	1
354	Towers and Fixtures	45 R3	60 R3	15
355	Poles and Fixtures	45 R4	50 R2	5
356	Overhead Conductor	42 S4	50 R2	8
357	Underground Conduit	50 R3	50 R3	0
358	Underground Conductor and Devices	35 S3	40 S3	5
Distribution				
360	Land and Land Rights	60 R3	60 R3	0
361	Structures and Improvements	41 R4	48 S6	7
362	Station Equipment	40 R2	48 R1	8
364	Poles, Towers, and Fixtures	27 R2	38 R1	11
365	Overhead Conductor and Devices	34 R1	37 R1.5	3
366	Underground Conduit	50 R2	48 R2.5	(2)
367	Underground Conductor and Devices	32 S0	34 R1.5	2
368	Line Transformers	41 R1	39 R1.5	(2)
369	Services	34 S0	32 S4	(2)
370	Meters			
Retire with AMS Deployment				
370	BPL/PLC Meters	31 R2	Amortize	
370	Conventional Meters	31 R2	Amortize	
Remain in Service after Deployment				
370	Substation	31 R2	11	(20)
370	IDR Meters	31 R2	15 R2	(16)
370	Meter Related Hardware	31 R2	20 R2	(11)
371	Installation on Customer Premises	15 R4	19 S6	4
373	Street Lighting	25 L0	24 S6	(1)
General				
389	Land and Land Rights	40 R2	50 R2	10
390	Structures and Improvements	37 R3	50 R1	13
391	Office Furniture and Equipment	20 S4	15 L0	(5)
392	Transportation Equipment	12 L2	13 L2	1
393	Stores Equipment	31 L5	40 R1.5	9
394	Tool, Shop, and Garage Equipment	28 R1	35 L0.5	7
395	Laboratory Equipment	25 L4	25 L2	0
396	Power Operated Equipment	17 L0	30 L0	13
397	Communication Equipment	19 S3	20 R2	1
398	Miscellaneous Equipment	28 R2	22 L2	(6)
399	Other Tangible Property	45 R4	45 R4	0

September 30, 2008 Update

Appendix D

ONCOR ELECTRIC DELIVERY
EXISTING AND PROPOSED NET SALVAGE RATES
FOR TRANSMISSION, DISTRIBUTION, AND GENERAL FUNCTIONS
AT DECEMBER 31, 2007

Account No.	Description	Existing Net Salvage	Proposed Net Salvage	Change
Transmission				
350	Land and Land Rights	0%	0%	0%
352	Structures and Improvements	0%	-50%	-50%
353	Station Equipment	0%	-15%	-15%
354	Towers and Fixtures	0%	-35%	-35%
355	Poles and Fixtures	0%	-100%	-100%
356	Overhead Conductor	0%	-65%	-65%
357	Underground Conduit	0%	-10%	-10%
358	Underground Conductor and Devices	0%	-10%	-10%
Distribution				
360	Land and Land Rights	0%	0%	0%
361	Structures and Improvements	-10%	-50%	-40%
362	Station Equipment	-10%	-15%	-5%
364	Poles, Towers, and Fixtures	-10%	-65%	-55%
365	Overhead Conductor and Devices	-10%	-55%	-45%
366	Underground Conduit	-10%	-50%	-40%
367	Underground Conductor and Devices	-10%	-10%	0%
368	Line Transformers	-10%	-20%	-10%
369	Services	-10%	-20%	-10%
370	Meters	-10%	-18%	-8%
Retire with AMS Deployment				
370	BPL/PLC Meters	-10%	-3.03%	7%
370	Conventional Meters	-10%	-5.72%	4%
Remain in Service after Deployment				
370	Substation	-10%	-15.00%	-5%
370	IDR Meters	-10%	-5.52%	4%
370	Meter Related Hardware	-10%	-14.48%	-4%
371	Installation on Customer Premises	-10%	-30%	-20%
373	Street Lighting	-10%	-25%	-15%
General				
389	Land and Land Rights	0%	0%	0%
390	Structures and Improvements	0%	-2%	-2%
391	Office Furniture and Equipment	0%	0%	0%
392	Transportation Equipment	10%	10%	0%
393	Stores Equipment	0%	0%	0%
394	Tool, Shop, and Garage Equipment	0%	0%	0%
395	Laboratory Equipment	0%	0%	0%
396	Power Operated Equipment	0%	10%	10%
397	Communication Equipment	0%	0%	0%
398	Miscellaneous Equipment	0%	0%	0%
399	Other Tangible Property	0%	0%	0%

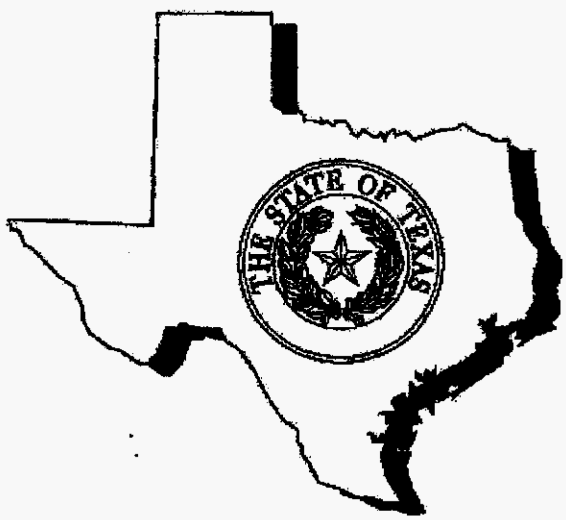
September 30, 2008 Update

SOAH DOCKET NO. 473-08-3681
PUC DOCKET NO. 35717

2008 DEC 10 AM 11: 28

FILING CLERK

APPLICATION OF ONCOR ELECTRIC	§	BEFORE THE STATE OFFICE
DELIVERY COMPANY LLC FOR	§	
AUTHORITY TO CHANGE RATES	§	OF
	§	
	§	ADMINISTRATIVE HEARINGS



DIRECT TESTIMONY
OF
NARA V. SRINIVASA, P.E.
INFRASTRUCTURE AND RELIABILITY DIVISION
PUBLIC UTILITY COMMISSION OF TEXAS

DECEMBER 10, 2008

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I analyzed the company's actuarial study for those account categories and agreed with the company proposed life parameter and the CRL for FERC accounts 357, 358, 391 through 398. I did not agree with the company's proposed life parameter and CRL for FERC Accounts 353, 354, 355, 356 and 362. For those six accounts I used the company provided observed life table from its depreciation study work papers[10] for placement band 1955-2007 and experience band 2002-2007 to conduct independent actuarial study and plotted the stub curve. I then compared it to the curve plot of my proposed life parameter and the company proposed life parameter. Next, I observed the curve plots for visual matching and conducted the statistical test to verify the best fit. The statistical test consisted of computing GFI and CI value. For each of those accounts I proposed a different life parameter than the company proposed because it was a better visual and mathematical fit. Table-2 below shows company proposed and my proposed life parameters and CRL's for the FERC accounts for which actuarial study was conducted.

Table-2 Summary of Actuarial Study Results

FERC ACCTS	DESCRIPTION	Company Proposed Life Parameter		Company Proposed CRL	Staff proposed Life Parameter		Staff proposed CRL
Transmission							
352	Structures and Improvements	48	S6	38.77	60	S6	50.63
353	Station Equipment	46	L0.5	37.80	60	L0.5	51.24
354	Towers and Fixtures	60	R3	43.95	60	R3	43.95
355	Poles and Fixtures	50	R2	41.22	60	R2	51.07
356	Overhead Conductors and Devices	50	R2	39.22	60	R3	47.79
357	Underground Conduit	50	R3	40.96	50	R3	40.96
358	Underground	40	S3	31.52	40	S3	31.52

[10] Company witness Watson depreciation study work papers filed on CD in response to staff RFI 2-07, and ATOC RFI set No.3

FERC ACCTS	DESCRIPTION	Company Proposed Life Parameter		Company Proposed CRL	Staff proposed Life Parameter		Staff proposed CRL
	Conductors and Devices						
Distribution Station							
362	Station Equipment	48	R1	36.62	50	R1	38.59
General	**Depreciable**						
389	Land Rights	50	R2	34.70	50	R2	34.70
390	Structures and Improvements	50	R1	36.09	50	R1	36.09
397	Communication Equipment	22	L2	8.22	22	L2	8.22
Accounts Using AR 15:							
391	Office Furniture and Equipment	15		11.28	15		11.28
392	Transportation Equipment	13		7.31	13		7.31
393	Stores Equipment	40		18.76	40		18.76
394	Tools, Shop and Garage Equipment	35		22.71	35		22.71
395	Laboratory Equipment	25		14.82	25		14.82
396	Power Operated Equipment	30		23.53	30		23.53
397	Communication Equipment	20		7.94	20		7.94
398	Miscellaneous Equipment	22		11.67	22		11.67

Q Please explain how the SPR method of life analysis was used in the Oncor's depreciation study.

A. Oncor used the SPR method for determining the life parameters for most of the account categories for which the company had no aged data. The company's proprietary

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Q.

Distribution Poles, Towers & Fixtures. For Account 364 – Distribution Poles, Towers & Fixtures, please provide the following:

a. All support and justification as to why the average service life was increased only to 37 years given the statements on Exhibit CRC – 1, page 569 that the actuarial results suggested average service life of 38 to 40 years, that the industry range produced an average of approximately 42 years, and that the life of wood poles is being extended.
b. The total number of poles segregated by different types of poles.
c. The dollar level of investment in each different type of pole.
d. The number of poles by type of pole retired by year for the past 10 years. Please provide the information both in hard copy and in electronic medium in Excel readable format.
e. The number of poles by type of pole added by year for the past 10 years. Please provide the information both in hard copy and in electronic medium in Excel readable format.
f. A detailed explanation of what factors resulted in the cost of removal for 2006 equaling approximately $17.3 million, specifically categorizing the cost of removal activity by type of investment retired.
g. A detailed explanation of what factors resulted in the cost of removal for 2007 to be approximately $17.3 million, specifically categorizing the cost of removal activity by type of investment retired.
h. The number of poles retired by year, for the past 10 years, that were not replaced.
i. The number of poles retired by year, for the past 10 years, due to storm related activity.

A.

(a) The various bands run on the life analysis showed best fitting lives ranging from 37.4 years to 40 years. The 37-year life when matched with theR2 curve was the best match for the recorded data for this account. See Exhibit CRC-1, page 570.

(b) FPL uses three different types of poles throughout its distribution network: concrete, steel and wood. As of December 31, 2008, the total number for each of these types of poles was as shown below:

Type	Quantity
Concrete	73,074
Steel	12
Wood	1,074,260
Total	1,147,346

(c) As of December 31, 2008, the dollar level of investment in concrete, steel and wood poles was as shown below:

Type	Investment
Concrete	$140,784,185
Steel	16,860
Wood	656,784,297
Total	$797,585,342

(d) As of December 31, 2008, the number of poles retired by year for the past 10 years was as shown below:

Year	Concrete	Wood	Total Retirements
1999	1,002	11,754	12,756
2000	659	15,261	15,920
2001	561	10,882	11,443
2002	677	12,792	13,469
2003	655	13,009	13,664
2004	659	10,788	11,447
2005	677	24,027	24,704
2006	923	25,415	26,338
2007	838	17,940	18,778
2008	829	16,727	17,556

(e) As of December 31, 2008, the number of poles added by year for the last 10 years was as shown below:

Year	Concrete	Wood	Total Additions
1999	1,582	23,651	25,233
2000	1,606	24,675	26,281
2001	1,270	23,465	24,735
2002	907	20,384	21,291
2003	2,555	33,585	36,140
2004	1,624	20,656	22,280
2005	1,116	26,816	27,932
2006	2,370	49,941	52,311
2007	2,888	36,317	39,205
2008	4,663	21,160	25,823

(f) The factors which resulted in the cost of removal for 2006 equaling approximately $17.3M, were primarily reliability projects, relocation of facilities and new services.

(g) The factors which resulted in the cost of removal for 2007 being approximately $9.9M (not $17.3M), were primarily infrastructure hardening, relocation of facilities, reliability projects, new services and restoration work.

(h) FPL cannot provide this information, as its records are not maintained at this level of detail.

(i) The number of poles retired by year, for the past 10 years, due to storm-related activity was as shown below:

Year	Total Storm Retirements
2005	12,028
2006	4
2007	400
2008	566

Note: There were no poles retired as a result of storm activity from 1999 to 2004 (accounting for poles replaced as a result of the 2004 storms occurred in 2005).

Year	Description	Quantity - Feet		Cost
1999	CBL, B, 600V, ALL	13,742	$	37,289
	CBL, B, PRI, AL, ALL	834,305	$	2,934,578
	CBL, B, PRI, CU, ALL	14,849	$	141,806
1999 Total		862,896	$	3,113,673
2000	CBL, B, 600V, ALL	49,406	$	141,898
	CBL, B, PRI, AL, ALL	1,648,596	$	5,860,911
	CBL, B, PRI, CU, ALL	14,915	$	135,393
2000 Total		1,712,917	$	6,138,202
2001	CBL, B, 600V, ALL	43,999	$	105,825
	CBL, B, PRI, AL, ALL	1,205,999	$	4,301,809
	CBL, B, PRI, CU, ALL	12,557	$	414,136
2001 Total		1,262,555	$	4,821,770
2002	CBL, B, 600V, ALL	38,628	$	64,953
	CBL, B, PRI, AL, ALL	846,914	$	2,483,320
	CBL, B, PRI, CU, ALL	40	$	1,272
2002 Total		885,582	$	2,549,546
2003	CBL, B, 600V, ALL	(282)	$	(531)
	CBL, B, PRI, AL, ALL	46,112	$	115,003
	CBL, B, PRI, CU, ALL	2,647	$	7,006
2003 Total		48,477	$	121,478
2004	CBL, B, 600V, ALL	(89)	$	(153)
	CBL, B, PRI, AL, ALL	68,201	$	185,877
	CBL, B, PRI, CU, ALL	1,843	$	26,938
2004 Total		69,955	$	212,662
2005	CBL, B, 600V, ALL	3	$	5
	CBL, B, PRI, AL, ALL	44,999	$	124,907
	CBL, B, PRI, CU, ALL	1,765	$	13,677
2005 Total		46,767	$	138,589
2006	CBL, B, PRI, AL, ALL	2,423	$	6,092
	CBL, B, PRI, CU, ALL	786	$	3,482
2006 Total		3,209	$	9,574
2007	CBL, B, PRI, AL, ALL	8,371	$	24,600
	CBL, B, PRI, CU, ALL	962	$	3,621
2007 Total		9,333	$	28,222
2008	CBL, B, PRI, AL, ALL	12,659	$	37,536
	CBL, B, PRI, CU, ALL	547	$	2,235
2008 Total		13,206	$	39,771

NOTE: "CU" in the description denotes Copper.

Q.
Distribution Line Transformers. For Account 368 – Distribution Line Transformers, please provide the following:

a. The number of pole versus pad mounted transformers and the corresponding dollar value for each category.
b. The number pole versus pad mounted transformers retired by year, for the past 10 years, along with the corresponding dollar value by year.
c. The underlying causes of retirement segregated by type of cause for the retirements that occurred during the age intervals 0.5, 1.5, and 2.5 years of age, as set forth on Exhibit CRC – 1, page 615. Further provide all reasons FPL believes that such level of retirements at such an early age is indicative of future retirements applicable to existing investment, specifically identifying the relationship of pole mounted and pad mounted transformers in FPL's response, as well as all support and justification for the responsive information.

A.

(a) FPL's asset database does not identify all transformers by "pole mounted" or "pad mounted". The classification is by KVA groupings. See Attachment 1 for the numbers and corresponding dollars by KVA groupings:

(b) FPL's asset database does not identify all transformers by "pole mounted" or "pad mounted." The classification is by KVA groupings. The list of transformers retired for the past 10 years are based on KVA groupings (See Attachment 2).

(c) The major cause of the retirements in these early age intervals related to deterioration or failure of single-phase voltage regulators. Information for those age intervals as well as all age intervals was used in the life analysis. No specific year was analyzed but rather the information derived from examining all years (1941 through 2007) and bands was used to determine estimated curve and average service life. This resulting estimate is based on the best information we have available for this account and, because it is based on 65 years of actual history, we believe it is indicative of the future until new recorded information is available.

Q.
General Plant. Please provide a list of the ten largest general plant structures and improvements from a dollar standpoint, along with corresponding dollar amounts which were included in account 390. Further, provide a detailed description (not legal description) of the property. The description should include, but not be limited to, the type of construction, the size, and year of construction, current use, current property tax appraisals, or other appraisals and any plans for retirement of such structure in the future.

A.

FPL does not segregate costs by individual buildings for Account 390, but rather as an asset location for a given site. FPL has provided a listing of the ten largest asset locations by dollar value for Account 390. The asset locations provided below contain general office type facilities, care center facilities, service center buildings, warehousing, corporate record facilities, equipment test and repair facilities and other buildings supporting utility operations.

Item	Facility	Facility Name	Original Cost
1	MCE	MIAMI - CENTRAL SVC CNTR	4,559,664
2	MTC	METER TEST CENTER	4,751,015
3	ML3	BREVARD SERVICE CENTER	4,969,835
4	ERC	EQUIP REPAIR CENTER	6,024,394
5	WP3	W PALM BCH SVC CNTR	9,796,036
6	CSE	CUSTOMER SERVICE - EAST	13,705,203
7	PDC	PHYSICAL DIST CNTR	20,365,510
8	LFO	LEJEUNE/FLAGLER OFFICE	30,943,293
9	GO	GENERAL OFFICE	55,247,455
10	JB	JUNO OFFICE	108,932,758

Corporate Real Estate
Analysis of Building Construction Type and Square footage

Site	Gross sq feet	Construction type
Miami Central Service Center	34,064	CBS
Meter Test Center	21,731	CBS
Brevard Service center	38,405	Multiple Bldg's- combination CBS and pre-engineered metal buildings
Equip repair center	201,928	Precast Concrete
WPB Svc Ctr	28,884	CBS
Customer Service center	128,595	Drive it Construction
PDC	346,627	Multiple Bldg's- combination tilt up and pre-engineered metal buildings
LFO	229,606	Multiple Bldg's - Concrete
GO	709,643	Precast Concrete with window ribbing
JB	885,977	Multiple Bldg's - Precast Concrete with window ribbing

Square footage derived from REIS system for all areas except for GO and JB. These were provided from Building management system.

See Attachment No. 1 for additional information.

An appraisal was performed of the Juno Beach Headquarters. The document is confidential and will be made available by FPL for inspection and review by OPC at Rutledge, Ecenia & Purnell, P.A., 119 South Monroe Street, Suite 202, Tallahassee, Florida, during regular business hours, 8 a.m. to 5 p.m., Monday through Friday, upon reasonable notice to FPL's counsel.

Q.

Aircraft-Fixed Wing. For Account 392.01 – Aircraft-Fixed Wing, please provide the following:

a. All support and justification for the 7 year SQ curve.
b. All support and justification for the assumed 50% positive salvage.
c. The retirement of any fixed wing aircraft subsequent to 2007 along with all the underlying accounting information.

A.

A discrepancy was found in the Depreciation Study Report (Exhibit CRC-1) since it was filed. The net salvage information shown on Page 670 of that exhibit was incorrect. The revised page is attached to this interrogatory. The correct information was used, however, for the life analysis and the revision to the net salvage information does not affect the net salvage recommendations reached for this account.

a. The 7-year life for the Company fixed-wing aircraft is based on FPL's experience with such aircraft. This is also the life that is currently approved by the FPSC for this account.

b. The 50 percent positive salvage for the Company fixed-wing aircraft is based on FPL's experience with such aircraft. This is also the net salvage that is currently approved for this account.

c. No retirements have occurred in this account subsequent to 2007.

FLORIDA POWER & LIGHT

ACCOUNT 392.01 - AIRCRAFT - FIXED WING (JET)

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REUSE AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2003	6,106,955	0		0		4,028,000	66	4,028,000	66
2004									
2005	5,756,619	0		0		4,234,250	74	4,234,250	74
2006									
2007									
TOTAL	11,863,574	0		0		8,262,250	70	8,262,250	70
THREE-YEAR MOVING AVERAGES									
03-05	3,954,525	0		0		2,754,083	70	2,754,083	70
04-06	1,918,873	0		0		1,411,417	74	1,411,417	74
05-07	1,918,873	0		0		1,411,417	74	1,411,417	74
FIVE-YEAR AVERAGE									
03-07	2,372,715	0		0		1,652,450	70	1,652,450	70

Q.
Aircraft – Rotary Wing. For Account 392.02 – Aircraft – Rotary Wing, please provide the following:

a. All support and justification for the 7 year SQ curve.
b. All support and justification for the assumed 50% positive salvage.
c. The retirement of any fixed wing aircraft subsequent to 2007 along with all the underlying accounting information.
d. The date of installation for the rotary wing aircraft related retirement that occurred in 2003.
e. The date of installation for the rotary wing aircraft related retirement that occurred in 2005.

A.
A discrepancy was found in the Depreciation Study Report (Exhibit CRC-1) since it was filed. The net salvage information shown on Page 673 was incorrect. The revised pages are attached to this interrogatory. The correct information was used for the life analysis, however, and the revised net salvage information does not affect the net salvage recommendations reached for this account. Answers to this interrogatory Parts d and e relate to Aircraft-Fixed Wing (Jet).

a. Discussions with Company personnel in transportation and accounting revealed that 7 years was a proper life for the Company helicopters based on experience. This is also the life that is currently approved by the FPSC for this account.

b. Discussions with Company personnel in transportation and accounting revealed that 50 percent salvage is reasonable for the Company helicopters based on experience. This is also the net salvage that is currently approved by the FPSC for this account.

c. No retirements have occurred in this account subsequent to 2007.

d. (Aircraft-Fixed Wing Jet) - The date of installation for retirements that occurred in 2003 are December 1995 and August 2003.

e. (Aircraft-Fixed Wing Jet) - The date of installation for retirements that occurred in 2005 is December 1995.

FLORIDA POWER & LIGHT

ACCOUNT 392.01 - AIRCRAFT - ROTARY WING

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REUSE AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1988	418,512	0		0		408,516	98	408,516	98
1989	565,757	0		0		2,921	1	2,921	1
1990						399,616		399,616	
1991									
1992									
1993	1,713,152	0		0		1,268,000	74	1,268,000	74
1994									
1995									
1996									
1997									
1998									
1999	1,045,131	0		0		712,900	68	712,900	68
2000	1,063,189	0		0		712,900	67	712,900	67
2001									
2002									
2003									
2004									
2005	6,817,091	0		0		4,310,000	63	4,310,000	63
2006									
2007									
TOTAL	11,622,832	0		0		7,814,853	67	7,814,853	67

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE REUSE AMOUNT	PCT	GROSS SALVAGE FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
88-90	328,090	0		0		270,351	82	270,351	82
89-91	188,586	0		0		134,179	71	134,179	71
90-92						133,205		133,205	
91-93	571,051	0		0		422,667	74	422,667	74
92-94	571,051	0		0		422,667	74	422,667	74
93-95	571,051	0		0		422,667	74	422,667	74
94-96									
95-97									
96-98									
97-99	348,377	0		0		237,633	68	237,633	68
98-00	702,773	0		0		475,267	68	475,267	68
99-01	702,773	0		0		475,267	68	475,267	68
00-02	354,396	0		0		237,633	67	237,633	67
01-03									
02-04									
03-05	2,272,364	0		0		1,436,667	63	1,436,667	63

FLORIDA POWER & LIGHT

ACCOUNT 392.01 - AIRCRAFT - ROTARY WING

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES									
04-06	2,272,364	0		0		1,436,667	63	1,436,667	63
05-07	2,272,364	0		0		1,436,667	63	1,436,667	63
FIVE-YEAR AVERAGE									
03-07	1,363,418	0		0		862,000	63	862,000	63

364	0	Regular Retirement	1986	(2,979,731.55)	2,363,498.31	(289,352.30)	(1,238,797.08)	
364	1	Reimbursed Retirement	1986	(190,610.55)	195,790.53	(39,474.63)	(621,580.41)	Reimbursable Relocation
364	2	Sale	1986	(570.20)	200.78	(36.86)	(454.35)	Sales/Exchange
364	0	Regular Retirement	1987	(2,510,025.11)	2,414,463.34	(294,690.22)	(1,283,207.21)	
364	1	Reimbursed Retirement	1987	(156,562.92)	136,536.58	(28,218.75)	(309,000.39)	Reimbursable Relocation
364	2	Sale	1987	(223,294.21)	7,623.07	(335.19)	(117.53)	Sales/Exchange
364	0	Regular Retirement	1988	(2,858,504.58)	2,426,528.40	(329,759.80)	(1,428,444.66)	
364	1	Reimbursed Retirement	1988	(241,118.55)	164,512.19	(40,467.26)	(395,303.56)	Reimbursable Relocation
364	2	Sale	1988	7,465.71	161.35	(36.80)	-	Sales/Exchange
364	0	Regular Retirement	1989	(3,096,479.55)	2,649,348.75	(375,438.52)	(956,180.64)	
364	1	Reimbursed Retirement	1989	(204,433.26)	160,979.73	(42,393.94)	(590,364.01)	Reimbursable Relocation
364	2	Sale	1989	(432.21)	350.06	(317.01)	(0.05)	Sales/Exchange
364	0	Regular Retirement	1990	(3,357,461.71)	3,124,646.61	(445,854.59)	(1,518,519.42)	
364	1	Reimbursed Retirement	1990	(183,229.40)	155,368.09	(33,472.63)	(517,745.18)	Reimbursable Relocation
364	2	Sale	1990	(297.19)	0.94	(0.34)	(126.91)	Sales/Exchange
364	0	Regular Retirement	1991	(3,072,733.97)	2,906,200.06	(353,200.37)	(367,377.95)	
364	1	Reimbursed Retirement	1991	(261,431.20)	140,647.78	(41,015.80)	(537,714.42)	Reimbursable Relocation
364	2	Sale	1991	-	178.40	0.02	(1,741.05)	Sales/Exchange
364	0	Regular Retirement	1992	(2,988,549.69)	4,122,103.86	(352,235.71)	(1,086,824.09)	
364	1	Reimbursed Retirement	1992	(210,708.18)	162,604.61	(61,684.89)	(1,072,204.13)	Reimbursable Relocation
364	2	Sale	1992	(457.26)	(294.07)	(11.66)	0.09	Sales/Exchange
364	0	Regular Retirement	1993	(3,047,632.03)	4,051,447.45	(482,367.83)	(1,319,876.30)	
364	1	Reimbursed Retirement	1993	(161,864.75)	145,403.53	(42,629.06)	(744,234.18)	Reimbursable Relocation
364	2	Sale	1993	(891.40)	5.95	0.02	228.53	Sales/Exchange
364	7	Outlier Retirement	1993	(1,600,371.18)	1,821,687.13	(65,191.89)	(3,359,805.14)	Hurricanes/Major Storms
364	0	Regular Retirement	1994	(2,160,210.50)	3,590,818.82	(189,674.74)	(1,984,991.10)	
364	1	Reimbursed Retirement	1994	(155,600.90)	169,965.30	(31,029.08)	(370,132.54)	Reimbursable Relocation
364	2	Sale	1994	-	151.50	(0.05)	-	Sales/Exchange
364	7	Outlier Retirement	1994	(8,201.68)	8,377.82	(716.43)	(1,507.10)	Hurricanes/Major Storms
364	0	Regular Retirement	1995	(13,361,837.19)	3,030,323.53	(330,708.49)	(1,583,410.31)	
364	1	Reimbursed Retirement	1995	(137,390.65)	174,591.74	(23,543.81)	(377,687.27)	Reimbursable Relocation
364	7	Outlier Retirement	1995	(8,152.76)	9,838.85	1,355.28	(38,737.74)	Hurricanes/Major Storms
364	0	Regular Retirement	1996	(1,295,457.30)	2,699,136.74	(466,400.13)	(1,581,717.16)	
364	1	Reimbursed Retirement	1996	(112,765.98)	116,940.30	(24,146.48)	(868,864.65)	Reimbursable Relocation
364	2	Sale	1996	(114.64)	18.62	0.18	(357,646.03)	Sales/Exchange
364	0	Regular Retirement	1997	(1,132,044.56)	2,762,267.19	(592,918.52)	(1,056,738.81)	
364	1	Reimbursed Retirement	1997	(319,979.79)	(419,784.97)	(19,212.42)	154,632.99	Reimbursable Relocation
364	2	Sale	1997	(130,812.07)	4,212.87	0.01	(325,264.57)	Sales/Exchange
364	0	Regular Retirement	1998	(1,578,856.01)	3,743,969.58	(580,265.89)	(1,342,816.18)	
364	1	Reimbursed Retirement	1998	(516,884.17)	(225,882.14)	(5,445.19)	95,982.71	Reimbursable Relocation
364	2	Sale	1998	(1,192.11)	547.12	(1.01)	0.23	Sales/Exchange
364	0	Regular Retirement	1999	(4,183,014.53)	3,301,946.85	(285,936.82)	(1,094,166.80)	
364	1	Reimbursed Retirement	1999	(1,161,752.01)	154,396.26	(2,006.50)	(412,832.22)	Reimbursable Relocation
364	2	Sale	1999	(11,275.62)	3,232.22	(0.01)	(4,874.77)	Sales/Exchange
364	0	Regular Retirement	2000	(5,889,235.51)	3,458,651.63	(247,254.41)	(1,901,552.83)	
364	1	Reimbursed Retirement	2000	(761,070.30)	444,528.42	(125.22)	(944,436.13)	Reimbursable Relocation
364	2	Sale	2000	(8,729.33)	617.29	(0.11)	837,845.58	Sales/Exchange
364	0	Regular Retirement	2001	(3,982,649.39)	4,258,032.34	(153,841.66)	(190,438.70)	
364	1	Reimbursed Retirement	2001	(968,662.16)	505,104.73	(1,981.58)	(790,405.41)	Reimbursable Relocation
364	2	Sale	2001	(5,697.58)	1,305.53	0.01	237.84	Sales/Exchange
364	0	Regular Retirement	2002	(3,291,761.73)	4,101,694.11	(144,824.37)	(1,206,480.77)	
364	1	Reimbursed Retirement	2002	(519,603.38)	538,794.65	(349.82)	(404,982.51)	Reimbursable Relocation
364	2	Sale	2002	(343.74)	347.70	-	-	Sales/Exchange
364	0	Regular Retirement	2003	(3,090,157.79)	5,457,509.10	(111,069.38)	(1,182,799.13)	
364	1	Reimbursed Retirement	2003	(883,920.38)	997,921.86	611.52	(924,178.33)	Reimbursable Relocation
364	2	Sale	2003	-	0.67	-	-	Sales/Exchange
364	0	Regular Retirement	2004	(2,641,418.30)	4,358,423.75	(129,648.76)	(1,298,730.94)	
364	1	Reimbursed Retirement	2004	(822,583.77)	1,048,105.62	(529.79)	(428,293.94)	Reimbursable Relocation
364	0	Regular Retirement	2005	(3,162,218.73)	5,766,789.68	(188,519.26)	(2,049,254.59)	
364	1	Reimbursed Retirement	2005	(546,294.67)	724,057.41	56.14	(530,519.17)	Reimbursable Relocation
364	7	Outlier Retirement	2005	(3,486,155.53)	4,219,671.54	-	0.06	Hurricanes/Major Storms
364	0	Regular Retirement	2006	(8,140,755.03)	17,260,762.03	(28,628.40)	(1,519,491.14)	
364	1	Reimbursed Retirement	2006	(920,826.62)	1,175,971.03	365.33	(724,291.51)	Reimbursable Relocation
364	7	Outlier Retirement	2006	538,468.14	(624,165.19)	-	-	Hurricanes/Major Storms
364	0	Regular Retirement	2007	(5,333,649.23)	9,859,812.84	(83,324.51)	(1,042,954.95)	
364	1	Reimbursed Retirement	2007	(965,344.14)	1,142,097.19	-	(579,446.67)	Reimbursable Relocation
364	7	Outlier Retirement	2007	(167,559.39)	135,728.22	-	-	Hurricanes/Major Storms

EXCERPT FROM
OPC's 1ST POD No. 12
"2008 SALVAGE FILE XLS"

Q.

Net Salvage. If an item or a plant is retired with a replacement addition occurring and an outside party provides $1,000 associated with the replacement, how is the $1,000 accounted for (e.g., $1,000 gross salvage, $1,000 reduction to replacement addition cost, a 50/50 split of the $1,000, etc,) Further, please provide full justification for whatever methodology is employed. In addition, identify when FPL first implemented such policy.

A.

If an item or plant is retired with a replacement addition occurring, and an outside party provides $1,000 associated with the replacement, the transaction is accounted for as follows. For Contributions in Aid of Construction (CIAC) for Distribution Projects, the amounts are allocated between the cost of removal and additions based on the labor estimate for the job. CIAC related to transmission projects are treated as a reduction to the additions. For other third-party contributions, such as warranty and/or insurance, the amounts are applied against the removal costs, which are recorded in the Accumulated Provision for Depreciation Account.

This methodology is consistent with the CFR instructions for Account 108, Section B, which states:

> At the time of retirement of depreciable electric utility plant, this account shall be charged with the book cost of the property retired and the cost of removal and shall be credited with the salvage value and any other amounts recovered, such as insurance.

This methodology which is consistent with CFR instructions as outlined above, has been consistently applied as far back as FPL's records go, which is 1941.

Depr - OPC's 1st Request for POD (1-43) #21 Answer

Work Order	Account	Retired Year/Mo	In-service Year	Retirement Amount	Station Name	What was retired?	Why?
07794-070-0988	352.00	199109	1948	$85,310.47	Miami Substation	Building	Listed as more feasible to demolish than to renovate on supporting work order form 1721.
00241-009-0309	352.00	200106	1958	$21,093.17	Sanford Plant Switch Yard	Plant account level retirement posted; Unable to indentify at retirement unit level.	Removed existing 115kv switchyard in order to make room for combustion turbine.
00105-009-0384	352.00	200106	1958	$4,670.98	Kingsley Metering Station	Plant account level retirement posted; Unable to indentify at retirement unit level.	Plant account balance retired as part of station review and adjustment of plant records.
00138-009-0686	352.00	200106	1958	$2,091.40	System Relay Operations	Plant account level retirement posted; Unable to indentify at retirement unit level.	Plant account balance retired as part of station review and adjustment of plant records.
Grand Total:				$113,166.02			

#15219

PRELIMINARY NO.	Florida Power & Light Company EXPENDITURE REQUISITION	PAGE	OF		FORM A	TYPE OF ESTIMATE NUMERIC CD B	TYPE OF WORK NUMERIC CD C	D	BI NO	SPECIFIC ER NO.	LOC'N CODE
LM-90-25		1	3	01	1721	0	9	5	22	7794	98 8

DISTRICT Miami DIVISION Southern AUTHORIZED AMOUNT $ 1,100,000

02 DESCRIPTIVE TITLE A REMOVAL OF BUILDING AT MIAMI PLANT

FIFTH-SERIES

03 A FIX X — LOCATION MIAMI DADE COUNTY B 08 30 91

04 EST. MANHOURS A

DESCRIPTION (including franchise permit, right of way, crossing, joint use data)

This ER will authorize the engineering required to remove the asbestos and any other environmental material that could be hazardous to the health in addition to the actual demolition of the old Miami Power Plant building.

PURPOSE AND NECESSITY:

The building is in poor condition with a high level of Asbestos-Containing Materials (ACM), which should be removed from this facility. It is more feasible to demolish the facility than to renovate it. (System Protection and Transmission Engineering are in the process of relocating from the building).

PROCESSED
MAY 29 1990
CONTROL SECTION

RECEIVED
APR 27 1990
ACP-IDP

RECEIVED
APR 27 1990
GP/LAND

05	EASEMENTS REQUIRED YES ☐ NO ☐	
06	PERMITS REQUIRED YES ☐ NO ☐	
07	ORIGINAL COST OF PROPERTY RETIRED (2A)	109,651
08	NET BENEFIT TO ACCUM. PROV. FOR DEPRECIATION	
09	NET PLANT ADDITIONS, THIS LOCATION (11-7)	(109,651)
10	SUMMARY OF ESTIMATED COST	
11	PROPERTY ADDITIONS (2A)	
12	REMOVAL COST (2A)	1,100,000
13	SALVAGE	
14	TOTAL PLANT COST OF ER (11 + 12 - 13)	1,100,000
15	OPERATION MAINTENANCE	
16	TOTAL ER incl OPERATION MAINTENANCE	1,100,000
17	CIAC CONTRIBUTION CODE A	
18	LABOR/MATERIAL CONTRIBUTION	
19	CASH REQUIRED	1,100,000
20	MEMO EQUIPMENT TRANSFERRED IN	
21	MEMO EQUIPMENT TRANSFERRED OUT	
22	NET COST TRANSFERRED TO PLANT ADDTS.	
	TOTAL COST OF JOB	[illegible]00,000

	Date		Date
C. L. Martinez — ENGINEERED BY	4/20/90	Project Manager — APPROVED	4/20/90
W. H. Bonham — Mgr. RE & Fac. Plng — APPROVED	4/23/90	Dir. Land Management — APPROVED	4/23/90
APPROVED		APPROVED	
APPROVED		APPROVED EXECUTIVE COMMITTEE Date 7/12/90 Initials	
Group V. P. — AUTHORIZED	4/24/90	Terry O. Keith — APPROVED FOR ACCOUNTING	5/21/90

FPL 108136

PAGE NO.	PRELIMINARY NO.
3	LM-90-25

DETAILED ESTIMATE OF COST

	FORM A	TYPE EST B	SPECIFIC ER NO. C	BL ER D	LOC'N E	CPR LOCATION F
101	1721C	0	7794		988	1081053250

LINE NO	DESCRIPTION A	B	ACCT. C	ASSET NUMBER D	E	QUANTITY F	UNIT G	UNIT COST H	MATERIAL (SALVAGE) I	INSTALL/ REMOVE J	OTHER RECOVERIES K	ORIGINAL PROP. COST L	M
1	Structures & Improvements		352.0										
2													
3	Structure / Bldg.	R			48					1,098,750		93,311	
4	Structure / Bldg.	R			52					1,150		14,535	
5	Air Conditioning Unit	R			63					100		1,807	
6													
7													
8													
9													
10													
11													
12													
13													
14													
15													
16													
17													
18													
19													

Form 1721C (Revised) Rev 1/81

FPL 108137

FLORIDA POWER & LIGHT COMPANY
Schedule II - Accumulated Provision For Depreciation/Amortization As Of 12/31/06

Plant Account	Account Description	Beginning Balance	Accruals	Retirements	Cost of Removal	Salvage	Other Recoveries	Transfers	End of Year Balance	Exclusions	End Of Year (Adjusted)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)=a+b-c-d+e+f+g	(i)	(j)=(h)-(i)
PRODUCTION PLANT											
	Subtotal Depreciable	$6,224,072,810.11	$327,104,485.30	$210,289,865.12	$37,523,115.65	$360,000.00	$66,262,969.63	($283,211,990.63)	$6,086,775,293.64	$0.00	$6,086,775,293.64
	Subtotal Amortizable	17,120,343.80	7,126,719.18	5,599,323.77	0.00	0.00	0.00	(2,887.37)	18,644,851.84	0.00	18,644,851.84
	TOTAL PRODUCTION PLANT	$6,241,193,153.91	$334,231,204.48	$215,889,188.89	$37,523,115.65	$360,000.00	$66,262,969.63	($283,214,878.00)	$6,105,420,145.48	$0.00	$6,105,420,145.48
TRANSMISSION PLANT											
350.2	Easements	$62,453,141.04	$2,803,784.93	$360.99	$0.00	$0.00	$34,921.11	$0.00	$65,291,486.09	$22,956,074.00 (1)	$42,335,412.09
352.0	Structures & Improvements	21,314,596.67	1,669,366.87	189,222.51	35,122.56	35,274.61	0.00	1,763.45	22,796,656.53	4,376,888.00 (1)	18,419,768.53
353.0	Station Equipment	258,601,487.88	22,611,044.98	18,713,174.70	1,747,837.58	67,512.95	0.00	263,982.43	261,083,015.96	70,162,607.00 (1)	190,920,408.96
353.1	Station Equipment-Generator Step-Up Transf.	31,014,748.77	5,083,450.86	1,073,043.89	98,405.54	0.00	1,931.78	(13,667.99)	34,915,013.99	0.00	34,915,013.99
354.0	Towers & Fixtures	202,223,753.83	3,638,264.61	5,267,641.88	(267,295.85)	0.00	0.00	(17,032.64)	200,844,639.77	134,999,203.00 (1)	65,845,436.77
355.0	Poles & Fixtures	235,006,826.59	19,470,119.83	7,068,652.55	7,189,102.27	13,511.94	5,692,277.73	(504,891.64)	245,420,089.63	1,655,393.00 (1)	243,764,696.63
356.0	Overhead Conductors & Devices	272,867,503.30	14,601,653.22	12,337,029.85	3,101,785.75	94,012.14	373,624.06	521,090.06	273,019,067.18	85,433,299.00 (1)	187,585,768.18
357.0	Underground Conduit	23,133,199.28	766,572.89	327,107.49	151,777.56	0.00	0.00	(1,231,333.00)	22,189,554.12	0.00	22,189,554.12
358.0	Underground Conductors & Devices	29,121,656.96	1,362,027.18	231,013.07	84,979.10	0.00	0.00	(697,860.00)	29,469,831.97	0.00	29,469,831.97
359.0	Roads & Trails	28,645,339.91	1,468,850.69	16,471.14	15,795.40	0.00	0.00	0.00	30,081,924.06	6,361,251.00 (1)	23,720,673.06
	TOTAL TRANSMISSION PLANT	$1,164,382,254.23	$73,475,136.06	$45,223,718.07	$12,157,509.91	$210,311.64	$6,102,754.68	($1,677,949.33)	$1,185,111,279.30	$325,944,715.00 (1)	$859,166,564.30
DISTRIBUTION PLANT											
361.0	Structures & Improvements	$29,836,120.91	$3,285,262.48	$155,485.07	$59,606.10	($1,234.22)	$0.00	$16,231.10	$32,921,289.10	$67,511.00 (1)	$32,853,778.10
362.0	Station Equipment	339,105,706.18	31,045,802.69	13,554,375.44	2,722,480.56	19,570.11	1,275.05	(5,613,073.99)	348,282,424.04	468,046.00 (1)	347,814,378.04
362.9	Station Equipment - LMS	3,039,264.07	916,573.23	2,052,160.27	0.00	0.00	0.00	0.00	1,903,677.03	1,903,677.03 (2)	0.00
364.0	Poles, Towers & Fixtures	333,556,888.95	31,102,556.61	7,593,458.14	17,812,567.87	28,263.07	2,243,782.65	(2,457,899.00)	339,067,566.27	0.00	339,067,566.27
365.0	Overhead Conductors & Devices	518,131,983.09	42,241,177.89	13,584,076.38	11,433,714.16	36,597.10	(1,108,690.97)	(6,490,095.00)	527,793,181.57	0.00	527,793,181.57
366.6	Underground Conduit, Duct System	215,067,449.78	24,198,866.45	1,381,686.70	106,491.34	(54.27)	440,223.05	0.00	238,218,306.97	0.00	238,218,306.97
366.7	Underground Conduit, Direct Buried	13,866,453.01	1,164,473.38	42,266.20	83,002.54	1.86	85,596.75	(276,355.00)	14,714,901.26	0.00	14,714,901.26
367.6	UG Conductors & Devices, Duct System	245,297,790.20	28,661,840.61	15,208,350.13	1,480,426.53	32.82	2,325,059.68	(7,068,753.17)	252,527,193.48	0.00	252,527,193.48
367.7	UG Conductors & Devices, Direct Buried	233,760,533.45	9,504,695.93	1,312,823.94	50,074.48	5,495.04	14,960.40	(10,709,967.83)	231,212,818.57	0.00	231,212,818.57
367.8	BU Sys Clb Inj (8yr amrt)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
367.9	BU Sys Clb Inj (10yr amrt)	30,704,258.08	6,163,006.61	1,844,487.27	0.00	0.00	0.00	0.00	35,022,777.42	0.00	35,022,777.42
368.0	Line Transformers	566,430,263.93	74,845,946.41	25,150,051.03	10,041,787.26	72,838.77	213,061.10	0.00	606,370,271.92	0.00	606,370,271.92
369.1	Services, Overhead	75,055,117.12	6,996,165.70	1,298,427.07	2,346,315.65	1,297.06	164,117.60	0.00	78,571,954.76	0.00	78,571,954.76
369.7	Services, Underground	189,374,486.65	17,433,706.42	3,212,560.65	798,689.54	(8.04)	2,228,088.95	(2,466,631.00)	202,558,392.79	0.00	202,558,392.79
370.0	Meters	196,402,927.41	17,206,185.51	2,539,838.52	1,636,010.33	8,747.53	433.67	249,308.06	209,691,753.33	0.00	209,691,753.33
371.0	Installations On Customer Premises	46,455,222.19	3,591,500.77	239,496.48	141,419.80	5.79	302,288.53	(2,523,008.00)	47,445,093.00	0.00	47,445,093.00
371.2	Residential Load Management (LMS)	16,675,672.54	4,463,349.02	9,072,811.76	0.00	0.00	0.00	(249,308.06)	11,816,901.74	11,816,901.74 (2)	0.00
371.3	Commercial Load Mgmt (Non-ECCR)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
373.0	Street Lighting & Signal Systems	189,179,678.73	19,655,377.87	10,596,723.78	2,829,666.76	100,716.97	1,318,678.29	(7,253,049.00)	189,575,012.32	0.00	189,575,012.32
	SUBTOTAL DISTRIBUTION PLANT	$3,241,939,816.29	$322,476,487.58	$108,839,078.83	$51,542,252.92	$272,269.59	$8,228,874.75	($44,842,600.89)	$3,367,693,515.57	$14,256,135.77 (3)	$3,353,437,379.80
	Undistributed Cost Of Removal	(5,973,900.15)	0.00	0.00	(4,467,617.53)	0.00	0.00	0.00	(1,506,282.62)	0.00	(1,506,282.62)
	TOTAL DISTRIBUTION PLANT	$3,235,965,916.14	$322,476,487.58	$108,839,078.83	$47,074,635.39	$272,269.59	$8,228,874.75	($44,842,600.89)	$3,366,187,232.95	$14,256,135.77	$3,351,931,097.18
GENERAL PLANT : DEPRECIABLE											
390.0	Structures & Improvements	$127,132,327.52	$9,872,144.49	$1,381,630.50	$322,501.97	$0.00	$4,204.00	0.00	$135,304,543.54	$0.00	$135,304,543.54
391.6	Computer Equipment - LMS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
391.7	CILC Computer Equipment - LMS	32,051.04	0.00	32,051.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00
391.8	Computer Equipment - ECCR	39,715.91	10,033.50	0.00	0.00	0.00	0.00	0.00	49,749.41	49,749.41 (2)	0.00
392.0	Aircraft , Fixed Wing (Non-Jet)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
392.0	Aircraft, Rotary Wing	(1,216,842.13)	669,479.04	0.00	0.00	0.00	0.00	1,998,980.81	1,451,617.72	0.00	1,451,617.72
392.0	Aircraft, Fixed Wing (Jet)	11,124,818.00	3,435,201.60	0.00	0.00	0.00	0.00	(1,998,980.81)	12,561,038.79	0.00	12,561,038.79
392.1	Transportation - Automobiles	(168,534.32)	201,106.11	231,462.07	0.00	0.00	183,427.38	648,161.11	632,698.21	0.00	632,698.21
392.2	Transportation - Light Trucks	6,925,050.63	2,373,507.09	2,578,759.57	0.00	0.00	1,311,127.76	(9,429.73)	8,021,496.18	0.00	8,021,496.18
392.3	Transportation - Heavy Trucks	63,434,020.19	16,808,161.71	19,276,683.17	277.29	0.00	9,280,976.85	(1,449,620.82)	68,796,577.47	0.00	68,796,577.47
392.4	Transportation - Tractor-Trailers	344,921.30	49,681.08	0.00	0.00	0.00	0.00	(163,012.97)	231,589.41	0.00	231,589.41
392.9	Transportation - Trailers	4,269,063.38	639,358.91	1,023,598.29	0.00	0.00	339,128.37	11,455.16	4,235,407.53	0.00	4,235,407.53
395.6	Test Equipment - LMS	4,485.59	2,960.34	0.00	0.00	0.00	0.00	0.00	7,445.93	7,445.93 (2)	0.00
395.8	Measurement Equipment - ECCR	14,648.68	1,759.19	16,407.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00
396.1	Power Operated Equipt - Transportation	328,662.18	360,529.39	0.00	0.00	0.00	415,275.00	962,447.25	2,066,913.82	0.00	2,066,913.82
396.8	Power Operated Equipment - Other	32,862.25	1,591.44	0.00	0.00	0.00	0.00	0.00	34,453.69	0.00	34,453.69
397.4	Communications Equipment - ECCR	1,918.26	1,841.52	0.00	0.00	0.00	0.00	0.00	3,759.78	3,759.78 (2)	0.00
397.6	Communications Equipment - LMS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
397.8	Communications Equipment - Fiber Optics	3,829,664.54	745,956.32	5,708.78	0.00	0.00	0.00	0.00	4,569,912.08	0.00	4,569,912.08
398.6	Miscellaneous Equipment - LMS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SUBTOTAL GENERAL PLANT : DEPRECIABLE	$216,128,833.02	$35,173,311.73	$24,546,301.29	$322,779.26	$0.00	$11,534,139.36	($0.00)	$237,967,203.56	$60,955.12 (2)	$237,906,248.44

FINAL

Q.

Transmission, Towers & Fixtures. Please provide a detailed narrative identifying why the $220,453 cost of removal was incurred in 2006 for Account 354, as set forth on Exhibit CRC – 1, page 512. Further, specifically state why such level of cost of removal is typical for the remaining investment. Further, provide all workpapers, assumptions, considerations and/or material reviewed and relied upon in sufficient detail necessary to support FPL's response.

A.

See table below for detail of 2006 cost of removal. Cross-braces are corroding at the center and will not meet the original design criteria so replacement is required. Structure leg corrosion necessitated removal.

Description of Work	GL Account	Utility Acct.	Amount
Replace 1 tower 71-85 FT	108300	35400	13,117.24
Replace 12 Cross Braces on 500 KV Structures	108300	35400	98,349.69
Replace 12 Cross Braces on 500 KV Structures	108300	35400	108,985.60
			220,452.53

The amount for the year 2006 was not the only amount considered for this account. This recorded year along with the recorded amounts in the years 1986 through 2007 were examined as part of the net salvage analysis. No specific year was analyzed but rather all years and bands of years. The net salvage estimate is based on the best information available at the time for this account and because it is based on 22 years of actual history, we believe that it is indicative of the future until new recorded information is available.

Workpapers and reasoning for the salvage analysis for this account is in FPL's response to OPC's First Request for Production of Documents No. 12 "FPL 2008 Salvage File.xls", the account write-up in the Depreciation Study Report (CRC-1), and in FPL's response to OPC's Second Request for Production of Documents No. 14 in Docket No. 080677-EI.

	Transaction	Transaction	Transaction	Transaction	Adjusted Transaction	Cost of	Reuse	Final	
355	0	Regular Retirement	1986	(791,021.51)		707,828.68	(68,221.92)	(231,847.39)	
355	1	Reimbursed Retirement	1986	(163,214.96)		82,811.64	(21,820.19)	(925,707.40)	Reimbursable Relocation
355	0	Regular Retirement	1987	(971,565.75)		688,569.40	(33,156.74)	(41,966.84)	
355	1	Reimbursed Retirement	1987	(98,133.74)		121,314.09	(17,451.15)	(714,355.50)	Reimbursable Relocation
355	0	Regular Retirement	1988	(950,892.18)		1,010,365.61	(46,804.55)	(405,535.11)	
355	1	Reimbursed Retirement	1988	(355,990.31)		258,406.05	(166,375.73)	(2,311,800.64)	Reimbursable Relocation
355	0	Regular Retirement	1989	(1,100,893.20)		1,130,726.10	(142,557.67)	(387,479.10)	
355	1	Reimbursed Retirement	1989	(466,123.26)		116,972.18	(76,536.87)	(2,179,592.52)	Reimbursable Relocation
355	0	Regular Retirement	1990	(1,949,675.32)		1,068,249.09	(44,132.91)	(475,160.84)	
355	1	Reimbursed Retirement	1990	(314,361.37)		145,309.53	(116,901.56)	(376,694.85)	Reimbursable Relocation
355	0	Regular Retirement	1991	(1,162,105.50)		983,292.12	(69,106.61)	(142,654.09)	
355	1	Reimbursed Retirement	1991	(134,420.97)		61,513.23	(24,545.06)	(793,150.68)	Reimbursable Relocation
355	0	Regular Retirement	1992	(1,306,328.58)		1,655,225.69	(143,868.29)	(238,306.57)	
355	1	Reimbursed Retirement	1992	(239,147.38)		221,131.28	(28,100.32)	(1,530,827.67)	Reimbursable Relocation
355	7	Outlier Retirement	1992	-		13,502.03	-	-	Hurricanes/Major Storms
355	0	Regular Retirement	1993	(1,455,828.81)		1,623,260.38	(124,969.10)	(1,549,686.39)	
355	1	Reimbursed Retirement	1993	(242,726.86)		127,009.65	(53,299.28)	(749,580.40)	Reimbursable Relocation
355	7	Outlier Retirement	1993	(1,161,303.62)		961,474.37	(9,852.10)	(3,628,278.07)	Hurricanes/Major Storms
355	0	Regular Retirement	1994	(2,646,071.34)		1,775,005.30	(42,637.39)	708,059.34	
355	1	Reimbursed Retirement	1994	(239,344.47)		147,459.03	(42,353.65)	(3,216,013.60)	Reimbursable Relocation
355	7	Outlier Retirement	1994	-		-	3,191.44	1,519,835.06	Hurricanes/Major Storms
355	0	Regular Retirement	1995	(2,189,699.63)		1,287,484.52	(45,078.03)	(14,360.48)	
355	1	Reimbursed Retirement	1995	(118,830.99)		55,670.26	(2,881.47)	(1,249,879.76)	Reimbursable Relocation
355	7	Outlier Retirement	1995	-		-	-	(1,875.55)	Hurricanes/Major Storms
355	0	Regular Retirement	1996	(1,481,474.66)		1,552,480.84	(21,198.67)	(354,262.09)	
355	1	Reimbursed Retirement	1996	(331,804.73)		209,241.09	(17,839.99)	602,018.15	Reimbursable Relocation
355	7	Outlier Retirement	1996	-		-	6,663.21	99,864.57	Hurricanes/Major Storms
355	0	Regular Retirement	1997	(1,891,651.65)		1,455,606.45	(24,442.37)	(256,316.88)	
355	1	Reimbursed Retirement	1997	(368,328.38)		258,397.99	(10,158.12)	(1,237,991.01)	Reimbursable Relocation
355	0	Regular Retirement	1998	(1,369,820.61)		1,919,510.02	(8,254.87)	(193,756.68)	
355	1	Reimbursed Retirement	1998	(181,532.71)		158,106.89	(16,579.17)	(1,210,042.79)	Reimbursable Relocation
355	0	Regular Retirement	1999	(1,192,506.37)		2,358,341.00	(6,325.83)	(460,822.62)	
355	1	Reimbursed Retirement	1999	(330,762.91)		79,640.12	16,472.00	(1,581,306.84)	Reimbursable Relocation
355	2	Sale	1999	(14,615.01)		84.31	-	-	Sales/Exchange
355	0	Regular Retirement	2000	(2,413,498.89)		4,054,757.51	(2,693.01)	(1,791,071.25)	
355	1	Reimbursed Retirement	2000	(156,446.26)		368,935.04	-	(1,619,614.97)	Reimbursable Relocation
355	2	Sale	2000	-		13,566.16	-	(23,074.94)	Sales/Exchange
355	0	Regular Retirement	2001	(3,118,946.40)		3,723,659.89	(3,532.30)	(6,376,854.36)	
355	1	Reimbursed Retirement	2001	(345,080.78)		355,219.45	(3,059.51)	(1,782,764.02)	Reimbursable Relocation
355	2	Sale	2001	-		1,965.96	-	-	Sales/Exchange
355	0	Regular Retirement	2002	(5,996,986.82)		6,834,724.56	(4,262.25)	(6,397,815.31)	
355	1	Reimbursed Retirement	2002	(415,372.90)		586,794.41	-	(3,315,185.53)	Reimbursable Relocation

355	2	Sale	2002	-	23,454.65	-	-	Sales/Exchange
355	0	Regular Retirement	2003	(3,216,197.01)	5,452,853.89	(51,460.99)	(7,626.07)	
355	1	Reimbursed Retirement	2003	(3,485,938.43)	466,882.93	-	(1,576,065.91)	Reimbursable Relocation
355	0	Regular Retirement	2004	(5,322,365.31)	4,038,706.35	(8,001.93)	2,328,745.00	
355	1	Reimbursed Retirement	2004	(325,040.57)	189,182.88	-	(4,233,022.01)	Reimbursable Relocation
355	0	Regular Retirement	2005	(4,581,343.73)	3,846,712.88	(8,573.72)	(2,799,066.28)	
355	1	Reimbursed Retirement	2005	134,675.31	117,103.47	(1,561.33)	(1,047,829.42)	Reimbursable Relocation
355	2	Sale	2005	25,519.86	4,040.44	-	-	Sales/Exchange
355	7	Outlier Retirement	2005	(663,207.65)	1,418,700.10	-	46,178.37	Hurricanes/Major Storms
355	0	Regular Retirement	2006	(8,121,941.05)	7,029,959.53	(13,511.94)	(3,648,254.17)	
355	0	Regular Retirement	2006	8,121,941.05	(7,029,959.53)	13,511.94	3,648,254.17	
355	0	Regular Retirement	2006	(8,121,941.05)	5,921,440.49	(13,511.94)	(3,648,254.17)	
355	1	Reimbursed Retirement	2006	1,209,291.53	64,442.14	-	(2,044,023.56)	Reimbursable Relocation
355	1	Reimbursed Retirement	2006	1,209,291.53	64,442.14	-	(2,044,023.56)	
355	1	Reimbursed Retirement	2006	(1,209,291.53)	(64,442.14)	-	2,044,023.56	
355	2	Sale	2006	62,126.37	(29.86)	-	-	Sales/Exchange
355	2	Sale	2006	62,126.37	(29.86)	-	-	
355	2	Sale	2006	(62,126.37)	29.86	-	-	
355	7	Outlier Retirement	2006	(218,129.40)	94,730.46	-	-	Hurricanes/Major Storms
355	7	Outlier Retirement	2006	218,129.40	(94,730.46)	-	-	
355	7	Outlier Retirement	2006	(218,129.40)	94,730.46	-	-	
355	0	Regular Retirement	2007	(5,744,411.20)	5,579,725.92	2,186.14	(7,034,220.96)	
355	1	Reimbursed Retirement	2007	(263,151.33)	212,963.50	-	(2,119,157.25)	Reimbursable Relocation
				-68176621.44	65604522.16	-1493593.8	-66970197.88	
						Gross Salvage	-68463791.68	
						COR	65604522.16	
						Net Sal	2859269.52	
						Retirements	68176621.44	
						Net Sal %	4%	

Q.

Poles & Fixtures. For Account 355 – Poles & Fixtures, please provide the following:

a. The number and size of wood poles.
b. The number and size of concrete poles.
c. The number and year of addition for each type of pole.
d. The types of preservatives used to treat wood poles and the number of wood poles treated by each type of preservative.
e. The time frame during which each different type of wood preservative was applied to wood poles.
f. The dollar investment in wood poles segregated between the types of preservatives applied to poles.
g. The reasons for the negative gross salvage in 2004, as set forth on Exhibit CRC – 1, page 519. If the reason relates to accounting corrections, then provide the amounts by year that should have been booked originally.
h. The number of wood and concrete poles retired by year for the past 10 years.

A.

a. The surviving balances of wood poles by size are:

Type	Size	Total
Wood	POLE, WOOD, 30 - 44 FT	2195
	POLE, WOOD, 45 - 59 FT	3788
	POLE, WOOD, 60 - 74 FT	18760
	POLE, WOOD, 75 - 89 FT	6403
	POLE, WOOD, 90 - 110 FT	609
	POLE,WOOD,55 FT - TRANS	2
Wood Total		31757

b. The surviving balances of concrete poles by size are:

Type	Size	Total
Concrete	POLE, CONCRETE, 30 - 44	1054
	POLE, CONCRETE, 45 - 59	974
	POLE, CONCRETE, 60 - 74	7556
	POLE, CONCRETE, 75 - 89	17669
	POLE, CONCRETE, 90 - 115	18688
	POLE, CONCRETE, OVER 115	602
Concrete Total		46543

c. The number of poles by in-service year for the last ten years are:

Type	In-service Year	Total
Concrete	1999	1739
	2000	1400
	2001	1494
	2002	1780
	2003	2031
	2004	1731
	2005	1340
	2006	2700
	2007	1492
	2008	464
Concrete Total		**16171**
Steel	1999	13
	2000	4
	2001	0
	2003	2
	2004	2
	2005	12
	2006	101
	2008	10
Steel Total		**144**
Wood	1999	350
	2000	369
	2001	442
	2002	284
	2003	233
	2004	269
	2005	308
	2006	263
	2007	231
	2008	144
Wood Total		**2893**
Grand Total		**19208**

d. All poles are purchased pre-treated with creosote preservative.

e. Poles are treated by manufacturer prior to delivery to FPL.

f. All wood poles are treated. Cost of treatment is included in the price of the pole.

g. The reason for the year-end negative gross salvage in 2004 is the reversal of the prior month's accruals for contractual reimbursable work performed. December 2003 accrual reversals in the amount of $8.4 million occurred in January 2004. The normal accrual process entails recording amounts monthly and reversing those in the subsequent month.

h. The number of wood and concrete poles retired by year:

Type	Year	Quantity Retired
Wood	1999	1609
	2000	1095
	2001	1601
	2002	1886
	2003	1680
	2004	1460
	2005	1878
	2006	2985
	2007	2974
	2008	2228
Wood Total		**19396**
Concrete	1999	57
	2000	113
	2001	130
	2002	158
	2003	398
	2004	442
	2005	330
	2006	328
	2007	435
	2008	164
Concrete Total		**2555**

	Transaction	Transaction	Transaction	Transaction	Adjusted Transaction	Cost of	Reuse	Final	
356	0	Regular Retirement	1986	(556,096.37)		561,321.35	(54,757.18)	(74,750.81)	
356	1	Reimbursed Retirement	1986	(58,853.75)		34,759.09	(14,032.02)	(470,163.88)	Reimbursable Relocation
356	0	Regular Retirement	1987	(781,512.98)		608,341.12	(165,740.51)	(11,198.10)	
356	1	Reimbursed Retirement	1987	(92,016.28)		79,776.84	(34,630.32)	(347,957.94)	Reimbursable Relocation
356	0	Regular Retirement	1988	(1,090,168.07)		1,008,304.03	(183,223.54)	(106,240.52)	
356	1	Reimbursed Retirement	1988	(328,715.84)		124,116.96	(36,814.87)	(1,351,924.21)	Reimbursable Relocation
356	0	Regular Retirement	1989	(1,042,911.71)		711,181.45	(203,813.52)	(38,230.58)	
356	1	Reimbursed Retirement	1989	(410,630.97)		31,289.55	(46,250.98)	(707,754.37)	Reimbursable Relocation
356	0	Regular Retirement	1990	(1,848,583.13)		792,439.47	(418,387.74)	(200,045.30)	
356	1	Reimbursed Retirement	1990	(160,711.24)		52,676.83	(55,601.40)	(888,147.23)	Reimbursable Relocation
356	0	Regular Retirement	1991	(843,690.44)		385,552.50	(213,190.71)	(25,627.45)	
356	1	Reimbursed Retirement	1991	(64,623.66)		29,247.21	(32,923.06)	(12,210.62)	Reimbursable Relocation
356	0	Regular Retirement	1992	(1,041,407.54)		1,576,771.93	(225,240.37)	(11,524.62)	
356	1	Reimbursed Retirement	1992	(78,785.68)		55,089.86	(12,801.50)	(652,960.67)	Reimbursable Relocation
356	7	Outlier Retirement	1992	-		13,264.25	-	-	Hurricanes/Major Storms
356	0	Regular Retirement	1993	(2,529,684.03)		1,427,039.76	(154,084.40)	(18,030.99)	
356	1	Reimbursed Retirement	1993	(250,457.16)		101,523.72	(47,586.85)	(459,628.25)	Reimbursable Relocation
356	7	Outlier Retirement	1993	(1,723,892.29)		777,991.50	(642.09)	(435,664.05)	Hurricanes/Major Storms
356	0	Regular Retirement	1994	(3,361,313.33)		737,893.94	(186,701.05)	(826,302.40)	
356	1	Reimbursed Retirement	1994	(199,804.00)		76,268.47	(3,968.48)	(546,387.74)	Reimbursable Relocation
356	7	Outlier Retirement	1994	-		-	-	(1,456,288.66)	Hurricanes/Major Storms
356	0	Regular Retirement	1995	(1,558,486.78)		793,744.29	(75,857.42)	(5,131.26)	
356	1	Reimbursed Retirement	1995	(52,686.00)		22,570.52	(15,649.37)	(332,548.03)	Reimbursable Relocation
356	0	Regular Retirement	1996	(1,940,670.53)		748,494.35	(116,505.30)	(21,833.37)	
356	1	Reimbursed Retirement	1996	(245,309.62)		101,409.88	(6,466.88)	(613,455.29)	Reimbursable Relocation
356	7	Outlier Retirement	1996	-		-	-	82,038.10	Hurricanes/Major Storms
356	0	Regular Retirement	1997	(5,120,099.39)		967,510.94	(72,553.50)	(24,031.55)	
356	1	Reimbursed Retirement	1997	(142,963.22)		100,244.15	(6,607.87)	(672,241.54)	Reimbursable Relocation
356	0	Regular Retirement	1998	(1,724,380.53)		1,938,108.81	(4,330.05)	(3,826.14)	
356	1	Reimbursed Retirement	1998	(159,641.44)		104,068.02	(12,921.91)	(206,590.83)	Reimbursable Relocation
356	0	Regular Retirement	1999	(1,019,594.57)		1,244,490.00	(7,423.56)	(117,827.79)	
356	1	Reimbursed Retirement	1999	(195,888.04)		17,603.76	(33,719.01)	(368,236.56)	Reimbursable Relocation
356	2	Sale	1999	(9,837.70)		43.44	-	-	Sales/Exchange
356	0	Regular Retirement	2000	(1,662,236.06)		2,579,227.22	(86,211.96)	(133,758.71)	
356	1	Reimbursed Retirement	2000	(61,509.53)		153,692.61	-	(860,254.50)	Reimbursable Relocation
356	2	Sale	2000	(10,213,330.67)		6,448.53	-	(8,271,646.04)	Sales/Exchange
356	7	Outlier Retirement	2000	-		14,883.01	-	-	Hurricanes/Major Storms
356	0	Regular Retirement	2001	(3,673,114.32)		2,999,753.27	(27,279.80)	(138,791.10)	
356	1	Reimbursed Retirement	2001	(149,269.83)		169,047.71	(4,433.33)	(497,660.06)	Reimbursable Relocation
356	2	Sale	2001	-		933.54	-	-	Sales/Exchange
356	0	Regular Retirement	2002	(4,891,384.86)		3,185,508.67	(25,219.96)	(308,914.11)	
356	1	Reimbursed Retirement	2002	(496,432.41)		328,828.35	-	(1,934,710.18)	Reimbursable Relocation

356	2	Sale	2002	-	11,137.38	-	-	Sales/Exchange
356	0	Regular Retirement	2003	(2,508,083.79)	3,817,211.30	(25,962.56)	(122,803.16)	
356	1	Reimbursed Retirement	2003	(2,041,354.08)	251,664.00	-	(575,267.46)	Reimbursable Relocation
356	0	Regular Retirement	2004	(5,950,693.22)	3,265,551.58	(52,977.66)	(256,130.89)	
356	1	Reimbursed Retirement	2004	(173,468.29)	74,568.55	-	(2,128,341.59)	Reimbursable Relocation
356	0	Regular Retirement	2005	(4,639,177.75)	2,811,344.97	(5,745.45)	(662,044.39)	
356	1	Reimbursed Retirement	2005	33,766.60	52,552.20	(1,040.90)	(311,557.50)	Reimbursable Relocation
356	2	Sale	2005	11,126.21	1,793.55	-	-	Sales/Exchange
356	7	Outlier Retirement	2005	(603,101.57)	579,573.97	-	(36,130.62)	Hurricanes/Major Storms
356	0	Regular Retirement	2006	(12,920,332.84)	2,952,597.37	(94,012.14)	(343,604.07)	
356	0	Regular Retirement	2006	(7,885,812.37)	3,573,368.03	(94,012.14)	(343,604.07)	
356	0	Regular Retirement	2006	12,920,332.84	(2,952,597.37)	94,012.14	343,604.07	
356	1	Reimbursed Retirement	2006	645,727.88	36,277.94	-	(30,019.99)	Reimbursable Relocation
356	1	Reimbursed Retirement	2006	645,727.88	36,277.94	-	(30,019.99)	
356	1	Reimbursed Retirement	2006	(645,727.88)	(36,277.94)	-	30,019.99	
356	2	Sale	2006	85,050.64	-	-	-	Sales/Exchange
356	2	Sale	2006	85,050.64	-	-	-	
356	2	Sale	2006	(85,050.64)	-	-	-	
356	7	Outlier Retirement	2006	(147,475.53)	112,910.44	-	-	Hurricanes/Major Storms
356	7	Outlier Retirement	2006	147,475.53	(112,910.44)	-	-	
356	7	Outlier Retirement	2006	(5,181,996.00)	112,910.44	-	-	
356	0	Regular Retirement	2007	(4,455,235.82)	3,423,846.73	(36,670.44)	(38,171.74)	
356	1	Reimbursed Retirement	2007	(96,696.58)	116,386.60	-	-	Reimbursable Relocation

Question 59 Overhead Conductors & Devices For Account 356

Question 59

part b.

Type	Quantity - Feet	Quantity - Feet Percentage	Cost	Cost Percentage
CONDUCTOR, COPPER	4,908,438	2.94%	$3,066,011.63	1.02%
CONDUCTOR, ALL ALUMINUM	1,766,464	1.06%	$1,227,240.58	0.41%
CONDUCTOR, ACSR	139,552,516	83.49%	$262,706,125.92	86.99%
CONDUCTOR, ALL ALUMINUM ALLOY	20,917,404	12.51%	$34,982,915.77	11.58%
Grand Total:	167,144,822	100.00%	$301,982,293.90	100.00%

	Transaction	Transaction	Transaction	Transaction	Adjusted Transaction	Cost of	Reuse	Final	
364	0	Regular Retirement	1986	(2,979,731.55)		2,363,498.31	(289,352.30)	(1,238,797.08)	
364	1	Reimbursed Retirement	1986	(190,610.55)		135,790.53	(39,474.63)	(621,580.41)	Reimbursable Relocation
364	2	Sale	1986	(570.20)		200.78	(36.86)	(454.35)	Sales/Exchange
364	0	Regular Retirement	1987	(2,510,025.11)		2,414,463.34	(294,690.22)	(1,283,207.21)	
364	1	Reimbursed Retirement	1987	(156,562.92)		136,536.58	(28,218.75)	(309,000.39)	Reimbursable Relocation
364	2	Sale	1987	(223,294.21)		7,623.07	(335.19)	(117.53)	Sales/Exchange
364	0	Regular Retirement	1988	(2,858,504.58)		2,426,528.40	(329,759.80)	(1,428,444.66)	
364	1	Reimbursed Retirement	1988	(241,118.55)		164,512.19	(40,467.26)	(395,303.56)	Reimbursable Relocation
364	2	Sale	1988	7,465.71		161.35	(36.80)	-	Sales/Exchange
364	0	Regular Retirement	1989	(3,096,479.55)		2,649,348.75	(375,438.52)	(956,180.64)	
364	1	Reimbursed Retirement	1989	(204,433.26)		160,979.73	(42,393.94)	(590,364.01)	Reimbursable Relocation
364	2	Sale	1989	(432.21)		350.06	(317.01)	(0.05)	Sales/Exchange
364	0	Regular Retirement	1990	(3,357,461.71)		3,124,646.61	(445,854.59)	(1,518,519.42)	
364	1	Reimbursed Retirement	1990	(183,229.40)		155,368.09	(33,472.63)	(517,745.18)	Reimbursable Relocation
364	2	Sale	1990	(297.19)		0.94	(0.34)	(126.91)	Sales/Exchange
364	0	Regular Retirement	1991	(3,072,733.97)		2,906,200.06	(353,200.37)	(367,377.95)	
364	1	Reimbursed Retirement	1991	(261,431.20)		140,647.78	(41,015.80)	(537,714.42)	Reimbursable Relocation
364	2	Sale	1991	-		178.40	0.02	(1,741.05)	Sales/Exchange
364	0	Regular Retirement	1992	(2,988,549.69)		4,122,103.86	(352,235.71)	(1,086,824.09)	
364	1	Reimbursed Retirement	1992	(210,708.18)		162,604.61	(61,684.89)	(1,072,204.13)	Reimbursable Relocation
364	2	Sale	1992	(457.26)		(294.07)	(11.66)	0.09	Sales/Exchange
364	0	Regular Retirement	1993	(3,047,632.03)		4,051,447.45	(482,367.83)	(1,319,876.30)	
364	1	Reimbursed Retirement	1993	(161,864.75)		145,403.53	(42,629.06)	(744,234.18)	Reimbursable Relocation
364	2	Sale	1993	(891.40)		5.95	0.02	228.53	Sales/Exchange
364	7	Outlier Retirement	1993	(1,600,371.18)		1,821,687.13	(65,191.89)	(3,359,805.14)	Hurricanes/Major Storms
364	0	Regular Retirement	1994	(2,160,210.50)		3,590,818.82	(189,674.74)	(1,984,991.10)	
364	1	Reimbursed Retirement	1994	(155,600.90)		169,965.30	(31,029.08)	(370,132.54)	Reimbursable Relocation
364	2	Sale	1994	-		151.50	(0.05)	-	Sales/Exchange
364	7	Outlier Retirement	1994	(8,201.68)		8,377.82	(716.43)	(1,507.10)	Hurricanes/Major Storms
364	0	Regular Retirement	1995	(13,361,837.19)		3,030,323.53	(330,708.49)	(1,583,410.31)	
364	1	Reimbursed Retirement	1995	(137,390.65)		174,591.74	(23,543.81)	(377,687.27)	Reimbursable Relocation
364	7	Outlier Retirement	1995	(8,152.76)		9,838.85	1,355.28	(38,737.74)	Hurricanes/Major Storms
364	0	Regular Retirement	1996	(1,295,457.30)		2,699,136.74	(466,400.13)	(1,581,717.16)	
364	1	Reimbursed Retirement	1996	(112,765.98)		116,940.30	(24,146.48)	(868,864.65)	Reimbursable Relocation
364	2	Sale	1996	(114.64)		18.62	0.18	(357,646.03)	Sales/Exchange
364	0	Regular Retirement	1997	(1,132,044.56)		2,762,267.19	(592,918.52)	(1,056,738.81)	
364	1	Reimbursed Retirement	1997	(319,979.79)		(419,784.97)	(19,212.42)	154,632.99	Reimbursable Relocation
364	2	Sale	1997	(130,812.07)		4,212.87	0.01	(325,264.57)	Sales/Exchange
364	0	Regular Retirement	1998	(1,578,856.01)		3,743,969.58	(580,265.89)	(1,342,816.18)	
364	1	Reimbursed Retirement	1998	(516,884.17)		(225,882.14)	(5,445.19)	95,982.71	Reimbursable Relocation
364	2	Sale	1998	(1,192.11)		547.12	(1.01)	0.23	Sales/Exchange
364	0	Regular Retirement	1999	(4,183,014.53)		3,301,946.85	(285,936.82)	(1,094,166.80)	

364	1	Reimbursed Retirement	1999	(1,161,752.01)	154,396.26	(2,006.50)	(412,832.22)	Reimbursable Relocation
364	2	Sale	1999	(11,275.62)	3,232.22	(0.01)	(4,874.77)	Sales/Exchange
364	0	Regular Retirement	2000	(5,889,235.51)	3,458,651.63	(247,254.41)	(1,901,552.83)	
364	1	Reimbursed Retirement	2000	(761,070.30)	444,528.42	(125.22)	(944,436.13)	Reimbursable Relocation
364	2	Sale	2000	(8,729.33)	617.29	(0.11)	837,845.58	Sales/Exchange
364	0	Regular Retirement	2001	(3,982,649.39)	4,258,032.34	(153,841.66)	(190,438.70)	
364	1	Reimbursed Retirement	2001	(968,662.16)	505,104.73	(1,981.58)	(790,405.41)	Reimbursable Relocation
364	2	Sale	2001	(5,697.58)	1,305.53	0.01	237.84	Sales/Exchange
364	0	Regular Retirement	2002	(3,291,761.73)	4,101,694.11	(144,824.37)	(1,206,480.77)	
364	1	Reimbursed Retirement	2002	(519,603.38)	538,794.65	(349.82)	(404,982.51)	Reimbursable Relocation
364	2	Sale	2002	(343.74)	347.70	-	-	Sales/Exchange
364	0	Regular Retirement	2003	(3,090,157.79)	5,457,509.10	(111,069.38)	(1,182,799.13)	
364	1	Reimbursed Retirement	2003	(883,920.38)	997,921.86	611.52	(924,178.33)	Reimbursable Relocation
364	2	Sale	2003	-	0.67	-	-	Sales/Exchange
364	0	Regular Retirement	2004	(2,641,418.30)	4,358,423.75	(129,648.76)	(1,298,730.94)	
364	1	Reimbursed Retirement	2004	(822,583.77)	1,048,105.62	(529.79)	(428,293.94)	Reimbursable Relocation
364	0	Regular Retirement	2005	(3,162,218.73)	5,766,789.68	(188,519.26)	(2,049,254.59)	
364	1	Reimbursed Retirement	2005	(546,294.67)	724,057.41	56.14	(530,519.17)	Reimbursable Relocation
364	7	Outlier Retirement	2005	(3,486,155.53)	4,219,671.54	-	0.06	Hurricanes/Major Storms
364	0	Regular Retirement	2006	(8,140,755.03)	17,260,762.03	(28,628.40)	(1,519,491.14)	
364	1	Reimbursed Retirement	2006	(920,826.62)	1,175,971.03	365.33	(724,291.51)	Reimbursable Relocation
364	7	Outlier Retirement	2006	538,468.14	(624,165.19)	-	-	Hurricanes/Major Storms
364	0	Regular Retirement	2007	(5,333,649.23)	9,859,812.84	(83,324.51)	(1,042,954.95)	
364	1	Reimbursed Retirement	2007	(965,344.14)	1,142,097.19	-	(579,446.67)	Reimbursable Relocation
364	7	Outlier Retirement	2007	(167,559.39)	135,728.22	-	-	Hurricanes/Major Storms

Q.
Distribution, Overhead Conductors & Devices. For Account 365 – Distribution, Overhead Conductors & Devices, please provide the following:

a. The quantity of copper conductor or cables by linear feet and dollar quantity.
b. The total linear feet of conductor or cable, by type of conductor or cable.
c. The linear feet and dollars of conductor or cables retired by year, by type of conductor or wire cable, for the past 10 years.
d. The quantity of the linear feet of conductor or cable retired by year, for the past 10 years due to storm related activity.
e. All reasons why FPL believes that an average service life of 43 years or longer would not also be a reasonable average service life.
f. All reasons FPL is aware of that caused the cost of removal in 2007 to be the highest percentage level experienced during the past 20 years.
g. All reasons FPL believes the cost of removal experienced during 2007 is representative of cost of removal for the remaining investment in the account.
h. The accounting transactions that caused the 2006 gross salvage to be a negative value, as set forth on Exhibit CRC – 1, page 581. The response should specifically identify all accounting reversals and the year the accounting reversals were corrected (e.g., $500,000 correction booked in 2006 for prior entry booked in 2004, etc.)

A.

(a) FPL records conductor or cables in its asset management system as either aluminum, copper, or other. Other can include either one of these, however, it does not identify the specific composition. As of December 31, 2008, FPL had on record 4,200,962 linear feet and $14,720,800 specifically identified as copper conductor/cable.

(b) See response in part (a) for explanation of FPL's recording of these type of assets. As of December 31, 2008, FPL had on record 461,355,168 linear feet of aluminum, 4,200,962 linear feet of copper, and 44,188,245 linear feet of other.

(c) See response in part (a) for explanation of FPL's recording of these type of assets. See Attachment No. 1 for amounts through December 31, 2008.

(d)

Year	Quantity-Feet
2005	5,117,484
2006	3,640
2007	420,307
2008	176,802

Note:
There were was no cable or conductor retired as a result of storm activity from 1999 to 2004 (accounting for cable and conductor replaced as a result of the 2004 storms occurred in 2005).

(e) Most of the bands run on the life analysis for this account indicated a 40-year life. The 40-year life when matched with the S0 curve was the best fit for the recorded data for this account. Lives higher than 43 years do not match the data as well as the 40 S0 life and curve. See Exhibit CRC-1, page 578.

(f) Without analyzing the specific conditions related to thousands of work orders, the main reason for the cost of removal is due to system upgrades and/or new system related retirements. Some of the reason may be due to timing differences (e.g., some retirements may be processed in one year, while the associated removal costs may span multiple years). Because of potential timing differences it is more desirable to base recommendations on analyses which span many years.

(g) The amount for the year 2007 was not the only amount considered for this account. This recorded year along with the recorded amounts in the years 1986-2007 were examined as part of the net salvage analysis. No specific year was analyzed but rather all years and bands of years. This estimate is based on the best information available at the time for this account and because the net salvage estimate is based on 22 years of actual history, we believe it is indicative of the future until new recorded information is available.

(h) The gross salvage for the year 2006 was a negative value as a result of a reversal of Other Recoveries recorded in the accumulated reserve in association with a Hurricane Jeanne work order. This work order should have been excluded from the reserve analysis.

Q.
Distribution Overhead Services. For Distribution Overhead Services - Account 369.1, please identify all analyses performed by the depreciation analyst to explain why the net salvage for investment in this account during the past 15 years noticeably exceeds the high end of the industry range indentified on Exhibit CRC – 1, page 621. To the extent no specific analysis was performed, provide all support and justification for such action.

A.
There was no analysis performed to determine why the net salvage percentages for this account are higher at Florida Power & Light than the industry statistics used in this study. No anomalies are known with the recording of salvage and cost of removal for this account. Although these net salvage percentages are higher than the industry statistics used for this study, FPL is aware of utilities not included in these industry statistics used in this study that have recently performed depreciation studies that show net salvage percentages for this account of exceeding negative 250 percent.

Q.
Distribution Overhead Services. For Account 369.1 – Distribution Overhead Services, please provide a detailed narrative explanation of the reasons why FPL's cost of removal for the past 15 years generally exceeds 100% on an annual basis. The response should specifically identify what activities are associated with cost of removal versus cost to replace in those instances where replacement of overhead service occurred. The response should provide a detailed accounting of how the amounts are established (e.g., estimated by cost estimators, actual charges by field crews, etc). Further, identify the number of overhead services retired by year, for the past 10 years.

A.
The reason why the cost of removal for the past 15 years has generally exceeded 100% on an annual basis is because removal cost is based on current costs for labor whereas the retirements are based on the historic cost associated with the vintage year. Additionally, some retirements are processed in one year and the associated removal costs may span multiple years (A).

The number of overhead services retired by year, for the past 10 years was as follows:

Year	Description	Retirements
1999	SERVICE OVERHEAD	15,110
2000	SERVICE OVERHEAD	20,806
2001	SERVICE OVERHEAD	17,465
2002	SERVICE OVERHEAD	20,873
2003	SERVICE OVERHEAD	20,744
2004	SERVICE OVERHEAD	22,878
2005	SERVICE OVERHEAD	49,940
2006	SERVICE OVERHEAD	31,043
2007	SERVICE OVERHEAD	25,864
2008	SERVICE OVERHEAD	5,997

(A) During the course of construction, all costs for the project are recorded under the project work order number using a holding account (Account No. 300.000). This holding account is designed to hold all project costs and then allocates these costs based on proportions established by the detail estimate. Removal cost being one component of the overall project, will have its own allocation parameters for material, labor and/or contractor payments. The criteria FPL uses in developing the systematic estimates is based on historical information and the knowledge of FPL engineering personnel.

Q.

Distribution Services–Underground. For Account 369.7 – Distribution Services – Underground, please provide the following:

a. The observed life tables associated with the actuarial analyses.
b. All basis for ignoring or discounting the results of FPL's specific analyses and retaining the 34-year average service life as referenced on Exhibit CRC – 1, page 629.
c. The underlying accounting associated with the $926,621 negative gross salvage during 2005 as set forth on Exhibit CRC – 1, page 631. Further, specifically identify the years associated with the negative gross salvage to the extent the amount reflects correction of prior year activities.
d. Whether it is FPL's policy is to abandon underground service in place when it can.
e. The number of underground services retired by year, for the past 10 years identifying the number abandoned in place and those removed.

A.

(a) See FPL's response to Depreciation-OPC's First Request for Production of Documents No. 13 "Depr-OPC 1st Set of POD No 13, 4 of 4.pdf."

(b) Although there were retirements for this account they were very small and did not provide significant life analysis information to base any estimate. There is still over 85 percent of the original investment remaining in this account. Until there is more data that provides information on life changes the consultant recommended that the currently approved life and curve be retained.

(c) The gross salvage for the year 2005 was a negative value as a result of a reversal of Other Recoveries recorded in the accumulated reserve in association with a Hurricane Jeanne work order. This work order should have been excluded from the reserve analysis.

(d) FPL's policy is to abandon underground service where it is replacing previously installed direct buried cable; however, when replacing previously installed cable in conduit, the old cable is pulled out for recycling and obtaining its salvage value.

(e) Below is the list of underground services retired by year, for the past 10 years. In reference to the number of underground services abandoned in place and those removed, FPL cannot provide this information, as its records are not maintained at this level of detail.

Year	Description	Retirements
1999	SERVICE,UG,BURIED	82
2000	SERVICE,UG,BURIED	1,417
2001	SERVICE,UG,BURIED	1,910
2002	SERVICE,UG,BURIED	1,192
2003	SERVICE,UG,BURIED	501
2004	SERVICE,UG,BURIED	97
2005	SERVICE,UG,BURIED	53
2006	SERVICE,UG,BURIED	32
2007	SERVICE,UG,BURIED	2

	Transaction	Transaction	Transaction	Transaction	Adjusted Transaction	Cost of	Reuse	Final	
369.7	0	Regular Retirement	1986	(359,501.06)		23,578.36	(1,751.34)	(9,184.23)	
369.7	1	Reimbursed Retirement	1986	(20,222.45)		1,855.12	(104.58)	(19,861.70)	Reimbursable Relocation
369.7	2	Sale	1986	-		7.50	(0.01)	(0.02)	Sales/Exchange
369.7	0	Regular Retirement	1987	(1,189,668.77)		31,684.40	(2,835.75)	(5,465.07)	
369.7	1	Reimbursed Retirement	1987	(31,432.75)		805.28	(139.53)	(4,169.47)	Reimbursable Relocation
369.7	2	Sale	1987	(407,705.40)		(2.38)	-	0.02	Sales/Exchange
369.7	0	Regular Retirement	1988	(843,399.04)		16,042.84	(6,930.06)	(8,315.40)	
369.7	1	Reimbursed Retirement	1988	(104,297.92)		2,424.43	(329.95)	11,288.88	Reimbursable Relocation
369.7	0	Regular Retirement	1989	(809,883.75)		22,994.14	(8,642.57)	(12,656.74)	
369.7	1	Reimbursed Retirement	1989	(58,738.61)		8,675.83	(705.03)	(10,701.81)	Reimbursable Relocation
369.7	0	Regular Retirement	1990	(776,281.54)		21,813.17	(8,639.79)	(9,702.44)	
369.7	1	Reimbursed Retirement	1990	(37,028.99)		12,040.99	(718.51)	(7,503.89)	Reimbursable Relocation
369.7	0	Regular Retirement	1991	(612,088.68)		27,169.72	(4,656.83)	(10,103.65)	
369.7	1	Reimbursed Retirement	1991	(86,279.93)		11,377.34	(512.82)	(11,829.51)	Reimbursable Relocation
369.7	0	Regular Retirement	1992	(573,693.61)		76,731.15	(6,491.70)	(10,725.41)	
369.7	1	Reimbursed Retirement	1992	(17,393.07)		18,864.27	(123.33)	(6,613.32)	Reimbursable Relocation
369.7	0	Regular Retirement	1993	(970,411.71)		55,931.12	(5,545.45)	(61,130.51)	
369.7	1	Reimbursed Retirement	1993	(1,511.10)		12,754.97	(106.56)	(2,156.39)	Reimbursable Relocation
369.7	7	Outlier Retirement	1993	(12,664.28)		17.38	(4.94)	(13,441.22)	Hurricanes/Major Storms
369.7	0	Regular Retirement	1994	(779,514.91)		50,362.03	(5,677.42)	(49,188.49)	
369.7	1	Reimbursed Retirement	1994	(9,609.69)		13,021.83	(277.01)	(2,027.68)	Reimbursable Relocation
369.7	0	Regular Retirement	1995	(1,312,796.86)		74,254.19	(998.99)	(56,723.82)	
369.7	1	Reimbursed Retirement	1995	(2,306.88)		4,514.25	(73.14)	(2,629.78)	Reimbursable Relocation
369.7	7	Outlier Retirement	1995	(21,072.97)		860.10	(1.26)	(21,894.76)	Hurricanes/Major Storms
369.7	0	Regular Retirement	1996	(802,492.48)		39,007.51	(354.69)	(34,875.78)	
369.7	1	Reimbursed Retirement	1996	(22,116.83)		2,440.18	(24.94)	(14,672.79)	Reimbursable Relocation
369.7	2	Sale	1996	-		-	-	(6,027.17)	Sales/Exchange
369.7	0	Regular Retirement	1997	(968,815.30)		66,611.59	(294.58)	(56,476.36)	
369.7	1	Reimbursed Retirement	1997	(204,936.35)		5,755.55	(571.17)	(42,435.80)	Reimbursable Relocation
369.7	2	Sale	1997	(13,257.46)		(0.02)	-	-	Sales/Exchange
369.7	0	Regular Retirement	1998	(1,051,617.50)		42,409.45	(95.84)	(289,612.05)	
369.7	1	Reimbursed Retirement	1998	(276,916.10)		13,821.92	(67.09)	(16,205.25)	Reimbursable Relocation
369.7	0	Regular Retirement	1999	(801,997.01)		77,874.85	47.86	(114,745.31)	
369.7	1	Reimbursed Retirement	1999	(151,026.19)		8,214.28	(58.51)	(38,099.06)	Reimbursable Relocation
369.7	2	Sale	1999	-		1,381.17	-	(0.03)	Sales/Exchange
369.7	0	Regular Retirement	2000	(1,144,388.08)		71,390.15	(0.04)	(174,987.85)	
369.7	1	Reimbursed Retirement	2000	(43,892.92)		10,550.53	(0.25)	(16,900.80)	Reimbursable Relocation
369.7	2	Sale	2000	-		-	-	(7,801.53)	Sales/Exchange
369.7	0	Regular Retirement	2001	(1,641,796.76)		95,026.45	136.19	(157,946.29)	
369.7	1	Reimbursed Retirement	2001	(25,894.33)		7,887.20	0.46	(9,477.40)	Reimbursable Relocation
369.7	2	Sale	2001	-		179.54	-	(10.28)	Sales/Exchange
369.7	0	Regular Retirement	2002	(2,287,247.32)		203,058.68	(1,152.32)	(67,688.26)	

369.7	1	Reimbursed Retirement	2002	(5,380.18)	7,547.65	-	(4,978.04)	Reimbursable Relocation
369.7	0	Regular Retirement	2003	(2,921,831.21)	232,497.10	60.22	(188,287.60)	
369.7	1	Reimbursed Retirement	2003	(1,559.17)	4,126.92	-	(1,466.94)	Reimbursable Relocation
369.7	0	Regular Retirement	2004	(1,420,758.56)	319,569.35	3.45	(147,429.40)	
369.7	1	Reimbursed Retirement	2004	(1,195.75)	20,221.78	-	(404.53)	Reimbursable Relocation
369.7	0	Regular Retirement	2005	(2,256,920.34)	631,239.16	-	926,620.71	
369.7	1	Reimbursed Retirement	2005	(10,882.48)	514.15	-	(0.50)	Reimbursable Relocation
369.7	7	Outlier Retirement	2005	(1,991,654.38)	33,305.34	-	-	Hurricanes/Major Storms
369.7	0	Regular Retirement	2006	(3,725,824.00)	799,024.99	8.04	(2,225,451.78)	
369.7	1	Reimbursed Retirement	2006	(7,374.14)	(335.45)	-	(2,637.17)	Reimbursable Relocation
369.7	0	Regular Retirement	2007	(3,835,270.28)	904,980.93	(1.56)	(249,446.03)	
369.7	1	Reimbursed Retirement	2007	(566.67)	887.39	-	(377.18)	Reimbursable Relocation

SUPPLEMENTAL DIRECT TESTIMONY OF
R. KEITH PRUETT

I. BACKGROUND AND PURPOSE

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT EMPLOYMENT POSITION.

A. My name is R. Keith Pruett. My business address is 1601 Bryan Street, Dallas, Texas. I am Director of Corporate Accounting for Oncor Electric Delivery Company LLC ("Oncor" or "Company").

Q. ARE YOU THE SAME R. KEITH PRUETT WHO PREVIOUSLY SUBMITTED DIRECT TESTIMONY IN THIS DOCKET?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL DIRECT TESTIMONY?

A. The purpose of my supplemental direct testimony is to discuss a re-examination of, and resulting revision to, the amounts of meter-related removal costs and salvage credits provided to and relied upon by Company witness Mr. Dane Watson for purposes of preparing the Company's depreciation study. The Company agreed to re-examine meter removal costs in this Docket as part of the settlement of Docket No. 35718, *Request for Approval of Advanced Metering System (AMS) Deployment Plan and Request for AMS Surcharge.* The Commission adopted this portion of the settlement in Finding of Fact No. 29 in the Commission's August 29, 2008 Final Order. Additionally, I will discuss an unrelated accounting adjustment I have made to the Company's balance in distribution electric plant in service and the corresponding accumulated provision for depreciation of distribution electric utility plant. This adjustment is primarily for an amount of unprocessed/unrecorded distribution property retirements that would have been reflected in test

ONCOR ELECTRIC DELIVERY
EXISTING METERS AND RELATED REMOVAL COSTS

	Quantity						Removal Cost					
Property Unit	BPL/PLC	Conventional	Substation	IDR	Meter related hardware	Std Removal Cost Rate	BPL/PLC	Conventional	Substation	IDR	Meter related hardware	Total Removal Costs
0005	6,221	2,391,128				$ 5.63	$ 35,011	$ 13,457,075	[redacted]	$ -	$ -	
0010	1	114,566				$ 6.78	$ 7	$ 776,893	[redacted]	$ -	$ -	
0020	-	260				$ 4.29	$ -	$ 1,116	[redacted]	$ -	$ -	
0025	-	499				$ 4.29	$ -	$ 2,141	[redacted]	$ -	$ -	
0030	-	4,712				$ 31.81	$ -	$ 149,865	[redacted]	$ -	$ -	
0035	-	60,701				$ 31.81	$ -	$ 1,930,612	[redacted]	$ -	$ -	
9996	-	3				$ 15.00	$ -	$ 45	[redacted]	$ -	$ -	
0210	600,175	9,106				$ 4.35	$ 2,612,762	$ 39,641	[redacted]	$ -	$ -	
0230	22,226	-				$ 31.81	$ 706,866	$ -	[redacted]	$ -	$ -	
0270	12	-				$ 14.25	$ 171	$ -	[redacted]	$ -	$ -	
0005	-	-	-	4,167	-	$ 13.05	$ -	$ -	[redacted]	$ 54,379	$ -	
0010	-	-	-	1,316	-	$ 13.05	$ -	$ -	[redacted]	$ 17,174	$ -	
0030	-	-	-	55	-	$ 21.36	$ -	$ -	[redacted]	$ 1,175	$ -	
0035	-	-	-	2,126	-	$ 21.36	$ -	$ -	[redacted]	$ 45,411	$ -	
0040	-	-	-	1,005	2,036	$ 21.88	$ -	$ -	[redacted]	$ 21,989	$ 44,548	
0060	-	-	-	86	190	$ 142.44	$ -	$ -	[redacted]	$ 12,260	$ 27,064	
0100	-	-	-	14,704	178,769	$ 38.56	$ -	$ -	[redacted]	$ 568,986	$ 6,893,333	
0120	-	-	-	1,831	22,267	$ 101.86	$ -	$ -	[redacted]	$ 186,506	$ 2,268,117	
0140	-	-	-	6	73	$ -	$ -	$ -	[redacted]	$ -	$ -	
0150	-	-	-	10	125	$ 610.20	$ -	$ -	[redacted]	$ 6,102	$ 76,275	
0160	-	-	-	3,022	36,736	$ 68.78	$ -	$ -	[redacted]	$ 207,853	$ 2,526,702	
0170	-	-	-	6,757	193	$ 22.81	$ -	$ -	[redacted]	$ 154,127	$ 4,402	
0180	-	-	-	179	-	$ 24.32	$ -	$ -	[redacted]	$ 4,353	$ -	
0190	-	-	-	1,160	43	$ 24.58	$ -	$ -	[redacted]	$ 28,004	$ 1,057	
0060	-	-	-	2	-	$ 142.44	$ -	$ -	[redacted]	$ 285	$ -	
0280	-	-	248	-	-	[redacted]	$ -	$ -	[redacted]	$ -	$ -	
0281	-	-	249	-	-	[redacted]	$ -	$ -	[redacted]	$ -	$ -	
0282	-	-	192	-	-	[redacted]	$ -	$ -	[redacted]	$ -	$ -	
0283	-	-	429	-	-	[redacted]	$ -	$ -	[redacted]	$ -	$ -	
	628,634	2,580,975	1,118	36,446	240,432		$ 3,354,818	$ 16,357,389	$ -	$ 1,307,595	$ 11,841,497	$ 32,861,299
Substation Investment*		$ 12,964,214				15.00%			$ 1,944,632			$ 1,944,632
Total Removal Costs							$ 3,354,818	$ 16,357,389	$ 1,944,632	$ 1,307,595	$ 11,841,497	$ 34,805,931

* Property units 280-283

Q.

Structures & Improvements. For Account 390 – Structures & Improvements, please provide the following:

a. Categorization of what was retired in 2006 and 2007 as set forth on Exhibit CRC – 1, page 665.
b. What caused the negative 16% net salvage in 2006 and 2007, specifically identifying why such cost of removal activities are anticipated to continue.
c. An identification of what was retired in 2005 that resulted in a 22% gross salvage.
d. The number and corresponding description along with all other pertinent details associated with any sale of buildings that occurred during the past 10 years. Further, specifically indicate if the gain or loss on the sale such buildings were included in Account 108. To the extent any net proceeds from sales that occurred during the past 10 years were booked to an account other than Account 108 provide the underlying accounting information.

A.

a. See attachment for categorization of what was retired in 2006 and 2007 as set forth on Exhibit CRC – 1, page 665.

b. The estimate was based on the best information available and because the net salvage recommendation is based on 22 years of actual history, we believe that it is indicative of the future until new recorded information is available.

c. See attachment for the identification of what was retired in 2005.

d. See FPL's response to Depreciation-OPC's First Set of Interrogatories No. 27. FPL provided the number and corresponding description along with all other pertinent details associated with any sale of buildings that occurred from 2005 to year end 2008. No gain or loss on the sale such buildings were included in Account 108.

Account 311
Cost of Removal

Sum of SumOfAMOUNT		
Reason	**Work Orders**	**Total**
A=SYSTEM UPGRADE/NEW SYSTEM	05607-070-0904-007 - Replacement of Air handler and compressor unit in administration building with a 20-ton Magic-Aire verticle air handler and a 20-ton Lennox dual circuit condensing unit with additional	4,693.46
A=SYSTEM UPGRADE/NEW SYSTEM Total		4,693.46
O=OPERATION	02045-070-0912-007 - ppe intake canal retaining wall replacement (Site:port everglades-common)	256,043.00
	03702-070-0950-007 - replace pjk1 condensate sump pumps(06574130) (Site:st johns river power pk)	833.05
	03838-070-0950-007 - replace building #22 hvac units(06574403) (Site:st johns river power park)	595.83
	03931-070-0924-007 - ppe waste basin forwarding pump replacement (Site:port everglades common)	1,139.40
	03958-070-0936-007 - replace pmt cooling pond underdrain system (Site:manatee plant)	600,000.00
	04269-070-0913-007 - replace pcc elevator (Site:cape canaveral plant)	7,897.00
	04301-070-0917-007 - replace pmt f.o.transfer heaters (Site:manatee plant)	79.28
	04363-070-0979-007 - tpe fuel oil transfer pump replacement (Site:port everglades-terminal)	559.93
	04596-070-0950-007 - replace pjk p-1 sump pump(07574118) (Site:st johns river power park)	91.20
	04607-070-0950-007 - replace p-20a sump pumps(07574316) (Site:st johns river power park)	749.03
	04686-070-0901-007 - pcu u5b saltwell pump & motor replacement (Site:cutler power plant unit #6)	8,600.00
	04687-070-0901-007 - pcu u6 saltwell pump & motor replacement (Site:cutler power plant unit #5)	2,300.00
	04716-070-0913-007 - replace pcc1 ocw piping system (Site:cape canaveral plant)	84,301.84
	04781-070-0950-007 - replace wwt special filter assembly(07574208) (Site:st johns river power park)	3,344.75
	04833-070-0996-007 - replace tmt f.o.motor (Site:manatee plant)	864.17
	04834-070-0926-007 - replace ptf u2 open cooling water pump (Site:turkey point power plant un)	1,300.00
	04848-070-0913-007 - replace pcc pond liner (Site:cape canaveral plant)	44,497.13
	04880-070-0950-007 - replace sjrpp bld#4 hvac compressor(07574411) (Site:st johns river power)	250.46
	05012-070-0926-007 - ptf u2 bfp room roof replacement (Site:turkey point power plant un)	61,000.00
	05045-070-0950-007 - demolish sjrpp bldg #9(07574412) (Site:st johns river power park)	5,441.88
	05288-070-0904-007 - replace ac condenser in control room prv (Site:riviera plant common)	202.55
	05310-070-0950-007 - replace sjrpp turbine bldg elevator roof(07574415)(Site:st johns river power park)	2,000.00
	05334-070-0917-007 - pmt (common) install/replace ocw pump motor (Site:manatee unit (common))	554.30
	05354-070-0950-007 - replace p2 sump pumps a&b(07574123) (Site:st johns river power park)	1,322.00
	05388-070-0917-007 - pmt(common)install/replace ocw pump motor (Site:manatee power plant common	554.30
	05416-070-0924-007 - replace ppe unit 4 open cooling water motor (Site:port everglades unit 4)	871.43
O=OPERATION Total		1,085,392.53
V=IMPROVE	05611-070-0918-007 - Replace Martin Unit 1A open intake cooling water pump motor with Capital	1,444.95
V=IMPROVE Total		1,444.95
Grand Total		1,091,530.94

Account 324
Cost of Removal

Ledger Year	Reason	Work Order	Total
2004	O=OPERATION	01944-070-0915-007 - replace model dhp 4.16kv breakers (Site:st lucie unit 1)	2,013.09
		02014-070-0915-007 - replace 1a battery (Site:st lucie unit 1)	17,052.00
		02015-070-0915-007 - replace 1b battery (Site:st lucie unit 1)	17,052.00
	O=OPERATION Total		36,117.09
	T=OTHER	08104-070-0009-007 - 2004 capital credits received for psl #2 (Site:st lucie plant-unit 2)	(22,091.10)
	T=OTHER Total		(22,091.10)
	V=IMPROVE	02290-070-0914-007 - ptn u3 4160v switchgear breaker replacements (Site:turkey point nuclear-un)	5,407.33
		09553-070-0910-006 - plant data network-ddps/soer (Site:st lucie-unit 2)	741,535.18
	V=IMPROVE Total		746,942.51
2004 Total			760,968.50
2005	O=OPERATION	01945-070-0910-007 - replace model dhp 416kv breakers (Site:st lucie unit 2)	11,590.53
		02899-070-0915-007 - replace 4 16kv and 69kv model dhp breakers (Site:st lucie unit 1)	30.00
	O=OPERATION Total		11,620.53
	V=IMPROVE	09552-070-0915-006 - plant data network-phase 1 (Site:st lucie-unit 1)	796,630.93
	V=IMPROVE Total		796,630.93
2005 Total			808,251.46
2006	O=OPERATION	03973-070-0914-007 - ptn u3 control room recorder replacements (Site:turkey point nuclear)	2,696.81
		04128-070-0914-007 - ptn u4 control room recorder replacements (Site:turkey point nuclear)	1,382.52
		04838-070-0914-007 - ptn u4 control room recorder replacements (Site:turkey point nuclear)	2,696.81
	O=OPERATION Total		6,776.14
2006 Total			6,776.14
Grand Total			1,575,996.10

LIFE INPUT DATA ACCOUNT 354

FROM OCP'S 1ST POD 12, 2 OF 5 NOTEPAD

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35400000001990	000001087}	00000000000000000000000000000
35400000001992	0000000000	00008644860000000000000000000
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35400000001998	0000000000	000000003}0000000000000000000
35400000001999	0000000000	000004102K0000000000000000000
35400000002000	000007752R	00000000000000000000000000000
35400000002001	0000000000	0000000000000000000000676902M
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35400000002006	001148089N	00220452530000000000000000000
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35400000002007	0002147020	00013812540000000000000000000
35400000082007	067826507M	0000000000

Question 59 Overhead Conductors & Devices For Account 356

Question 59

part b.

		Quantity - Feet		Cost
Type	Quantity - Feet	Percentage	Cost	Percentage
CONDUCTOR, COPPER	4,908,438	2.94%	$3,066,011.63	1.02%
CONDUCTOR, ALL ALUMINUM	1,766,464	1.06%	$1,227,240.58	0.41%
CONDUCTOR, ACSR	139,552,516	83.49%	$262,706,125.92	86.99%
CONDUCTOR, ALL ALUMINUM ALLOY	20,917,404	12.51%	$34,982,915.77	11.58%
Grand Total:	167,144,822	100.00%	$301,982,293.90	100.00%

IOWA CURVES

Iowa Curves are the result of extensive analysis by Professor Robley Winfrey and others at Iowa State University. These curves represent retirement frequency patterns of empirically derived data over extensive periods of time. For depreciation purposes it has been determined that such curves provide curve shapes reflecting different patterns of retirement frequencies over time applicable to most plant in service of utilities.

The theory is that the generic curve shape will produce a definable pattern over time for the survival characteristics of utility property. Curves are broken down into left "L" modal, symmetrical "S" modal curves and right "R" modal curves. The L, S, and R simply reflect the anticipation of whether the pattern of retirements will exhibit characteristics of whether the survivor curve will cross the fifty (a50) percent surviving to the left of average service life, symmetrical with the average service life or to the right of the average service life. In addition, the numeric character zero through five (5) or six (6) in conjunction with the L, S, or R designation indicates the peakedness of the type of curve in question. In other words, a low modal (0 or 1) left, symmetrical or right curve will indicate that the retirement frequency experienced over the entire life span of the plan in question is relatively uniform. On the other than, a high modal (4, 5, 05 6) associated with a left, symmetrical or right curve indicates that the retirement frequency for such curves are low at the beginning and end of the life cycle, yet have their peak annual level of retirement near or around the average service life of the plant in question.

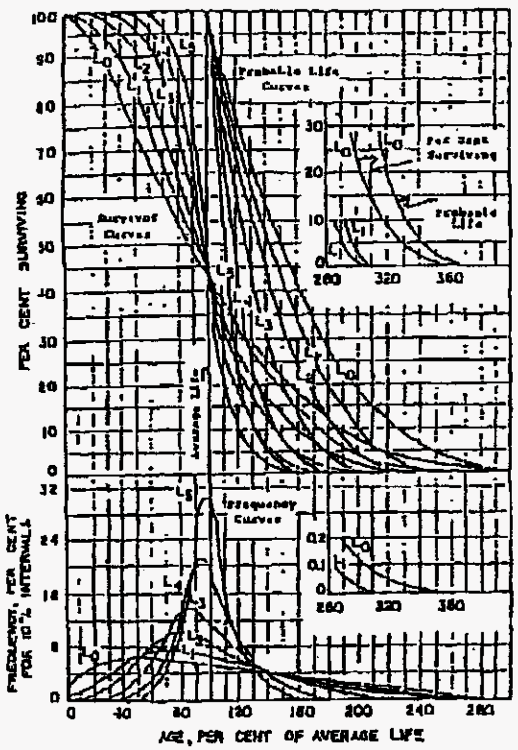


Fig. 16 Final Survivor, Probable-Life, and Frequency Curves for the Left-Modal Types
Winfrey, Bulletin 125, p. 30.

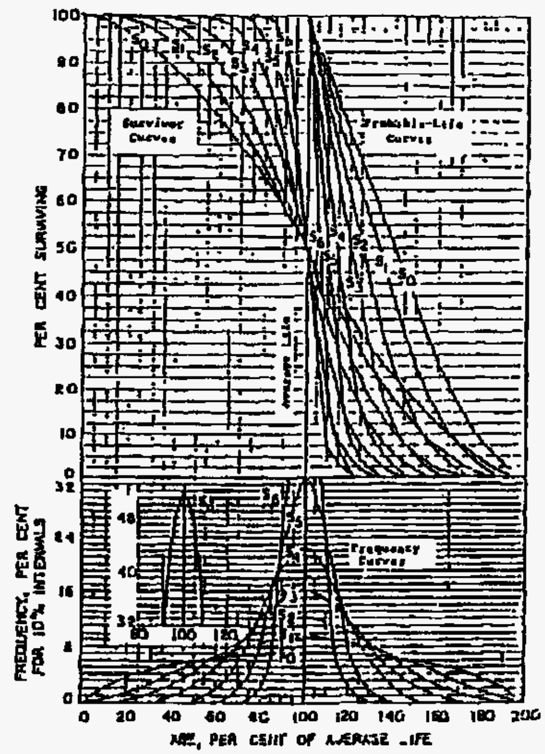


Fig. 17 Final Survivor, Probable-Life, and Frequency Curves for the Symmetrical Types
Winfrey, Bulletin 125, p. 31.

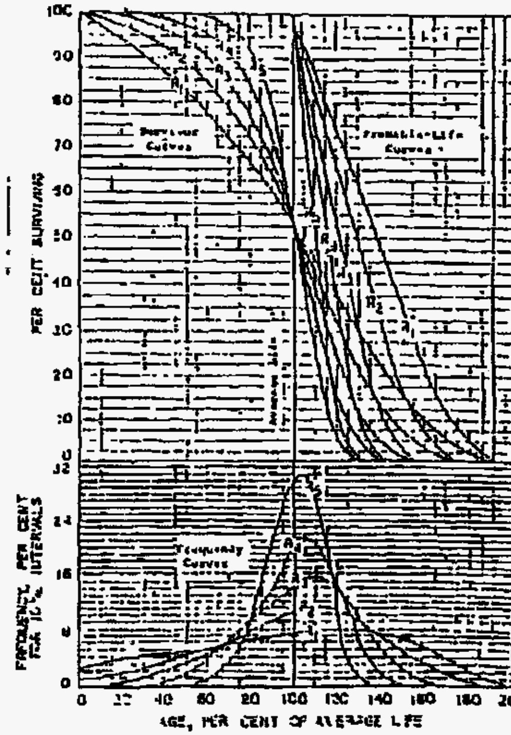


Fig. 18 Final Survivor, Probable-Life, and Frequency Curves for the Right-Modal Types
Winfrey, Bulletin 125, p. 33.

KIMBERLY H. DISMUKES

QUALIFICATIONS

Q. **WHAT IS YOUR EDUCATIONAL BACKGROUND?**

A. I graduated from Florida State University with a Bachelor of Science degree in Finance in March, 1979. I received an M.B.A. degree with a specialization in Finance from Florida State University in April, 1984.

Q. **WOULD YOU PLEASE DESCRIBE YOUR EMPLOYMENT HISTORY IN THE FIELD OF PUBLIC UTILITY REGULATION?**

A. In March of 1979 I joined Ben Johnson Associates, Inc., a consulting firm specializing in the field of public utility regulation. While at Ben Johnson Associates, I held the following positions: Research Analyst from March 1979 until May 1980; Senior Research Analyst from June 1980 until May 1981; Research Consultant from June 1981 until May 1983; Senior Research Consultant from June 1983 until May 1985; and Vice President from June 1985 until April 1992. In May 1992, I joined the Florida Public Counsel's Office, as a Legislative Analyst III. In July 1994 I was promoted to a Senior Legislative Analyst. In July 1995 I started my own consulting practice in the field of public utility regulation.

Q. **WOULD YOU PLEASE DESCRIBE THE TYPES OF WORK THAT YOU HAVE PERFORMED IN THE FIELD OF PUBLIC UTILITY REGULATION?**

A. Yes. My duties have ranged from analyzing specific issues in a rate proceeding to managing the work effort of a large staff in rate proceedings. I have prepared testimony, interrogatories and production of documents, assisted with the preparation of cross-examination, and assisted counsel with the preparation of briefs. Since 1979, I have been actively involved in more than 180 regulatory proceedings throughout the United States.

I have analyzed cost of capital and rate of return issues, revenue requirement issues, public policy issues, market restructuring issues, and rate design issues, involving telephone, electric, gas, water and wastewater, and railroad companies. I have also examined performance measurements, performance incentive plans, and the prices for unbundled network elements related to telecommunications companies. In addition, I have audited the purchased gas adjustment clauses of three gas companies and the fuel adjustment clause of one electronic company in the State of Louisiana.

Q. WHAT IS YOUR EXPERIENCE CONCERNING COST OF CAPITAL?

A. In the area of cost of capital, I have analyzed the following parent companies: American Electric Power Company, American Telephone and Telegraph Company, American Water Works, Inc., Ameritech, Inc., CMS Energy, Inc., Columbia Gas System, Inc., Continental Telecom, Inc., GTE Corporation, Northeast Utilities, Pacific Telecom, Inc., Southwestern Bell Corporation, United Telecom, Inc., and U.S. West. I have also analyzed individual companies like Connecticut Natural Gas Corporation, Duke Power Company, Idaho Power Company, Kentucky Utilities Company, Southern New England Telephone Company, and Washington Water Power Company.

Q. HAVE YOU PREVIOUSLY ASSISTED IN THE PREPARATION OF TESTIMONY CONCERNING REVENUE REQUIREMENTS?

A. Yes. I have assisted on numerous occasions in the preparation of testimony on a wide range of subjects related to the determination of utilities' revenue requirements and related issues.

I have assisted in the preparation of testimony and exhibits concerning the following issues: abandoned project costs, accounting adjustments, affiliate transactions, allowance for funds used during construction, attrition, cash flow analysis, conservation expenses and cost-effectiveness, construction monitoring, construction work in progress, contingent capacity sales, cost allocations, decoupling revenues from profits, cross-subsidization, demand-side management, depreciation methods, divestiture, excess capacity, excessive unaccounted for water, feasibility studies, financial integrity, financial planning, gains on sales, incentive regulation, infiltration and inflow, jurisdictional allocations, non-utility investments, fuel projections, margin reserve, mergers and acquisitions, pro forma adjustments, projected test years, prudence, tax effects of interest, working capital, off-system sales, reserve margin, royalty fees, separations, settlements, used and useful, weather normalization, and resource planning.

Companies that I have analyzed include: Aloha Utilities, Inc. (Florida), Alascom, Inc. (Alaska), Aqua Utilities Florida, Inc., Arizona Public Service Company, Arvig Telephone Company, AT&T Communications of the Southwest (Texas), AT&T Louisiana, Bayside Utility Services, Inc. (Florida), Blue Earth Valley Telephone Company (Minnesota), Bridgewater Telephone Company (Minnesota), Carolina Power and Light Company, CenterPoint Energy Arkla (Louisiana), Central Maine Power Company, Central Power and Light Company (Texas), Central

Telephone Company (Missouri and Nevada), Consumers Power Company (Michigan), C&P Telephone Company of Virginia, Continental Telephone Company (Nevada), C&P Telephone of West Virginia, Connecticut Light and Power Company, Danube Telephone Company (Minnesota), Duke Power Company, East Otter Tail Telephone Company (Minnesota), Easton Telephone Company (Minnesota), Eckles Telephone Company (Minnesota), El Paso Electric Company (Texas), Entergy Corporation, Entergy Gulf States (Louisiana), Florida Cities Water Company (North Fort Myers, South Fort Myers and Barefoot Bay Divisions), Florida Power and Light, General Telephone Company (Florida, California, and Nevada), Georgia Power Company, Jasmine Lakes Utilities, Inc. (Florida), Kentucky Power Company, Kentucky Utilities Company, KMP Telephone Company (Minnesota), KW Resort Utilities, Inc. (Florida), Idaho Power Company, Louisiana Gas Service Company, Oklahoma Gas and Electric Company (Arkansas), Kansas Gas & Electric Company (Missouri), Kansas Power and Light Company (Missouri), Lehigh Utilities, Inc. (Florida), Louisiana Land & Water Company Inc., Mad Hatter Utilities, Inc. (Florida), Mankato Citizens Telephone Company (Minnesota), Michigan Bell Telephone Company, Mid-Communications Telephone Company (Minnesota), Mid-State Telephone Company (Minnesota), Mountain States Telephone and Telegraph Company (Arizona and Utah), Nevada Bell Telephone Company, North Fort Myers Utilities, Inc., Northwestern Bell Telephone Company (Minnesota), Potomac Electric Power Company, Public Service Company of Colorado, Puget Sound Power & Light Company (Washington), Questar Gas Company (Utah), Sandy Creek Utility Services, Inc. (Florida), Sanlando Utilities Corporation (Florida), Sierra Pacific Power

Company (Nevada), South Central Bell Telephone Company (Kentucky), Southern Union Gas Company (Texas), Southern Bell Telephone & Telegraph Company (Florida, Georgia, and North Carolina), Southern States Utilities, Inc. (Florida), Southern Union Gas Company (Texas), Southwestern Bell Telephone Company (Oklahoma, Missouri, and Texas), Sprint, St. George Island Utility, Ltd., Tampa Electric Company, Texas-New Mexico Power Company, Tucson Electric Power Company, Twin Valley-Ulen Telephone Company (Minnesota), United Telephone Company of Florida, Virginia Electric and Power Company, Washington Water Power Company, and Wisconsin Electric Power Company.

Q. **WHAT EXPERIENCE DO YOU HAVE IN RATE DESIGN ISSUES?**

A. My work in this area has primarily focused on issues related to costing. For example, I have assisted in the preparation of class cost-of-service studies concerning Arkansas Energy Resources, Cascade Natural Gas Corporation, El Paso Electric Company, Potomac Electric Power Company, Texas-New Mexico Power Company, Southern Union Gas Company, and Questar Gas Company. I have also examined the issue of avoided costs, both as it applies to electric utilities and as it applies to telephone utilities. I have also evaluated the issue of service availability fees, reuse rates, capacity charges, and conservation rates as they apply to water and wastewater utilities.

Q. **WHAT FUEL AUDITS HAVE YOU CONDUCTED?**

A. I have conducted purchased gas adjustment audits of Louisiana Gas Company for the period 1971-2000, CenterPoint Energy Entex for the years 1971 through July 2001, and CenterPoint Energy Arkla for the years 1971 through December 2001. I have also audited the fuel adjust clause of Entergy Gulf States, Inc. for the period 1995-2004.

Q. HAVE YOU TESTIFIED BEFORE REGULATORY AGENCIES?

A. Yes. I have testified before the Arizona Corporation Commission, the Bay County Utility Regulatory Authority, the Connecticut Department of Public Utility Control, the Florida Public Service Commission, the Georgia Public Service Commission, Louisiana Public Service Commission, the Missouri Public Service Commission, the Public Utilities Commission of Nevada, the Public Utility Commission of Texas, and the Washington Utilities and Transportation Commission. My testimony dealt with revenue requirement, financial, policy, rate design, fuel, cost study issues unbundled network pricing, and performance measures concerning Aqua Utilities Florida, Inc., AT&T Communications of Southwest (Texas), Bayside Utility Services, Inc. (Florida), Cascade Natural Gas Corporation (Washington), Central Power and Light Company (Texas), Connecticut Light and Power Company, El Paso Electric Company (Texas), Embarq (Nevada), Florida Cities Water Company, Kansas Gas & Electric Company (Missouri), Kansas Power and Light Company (Missouri), KW Resort Utilities, Inc. (Florida), Houston Lighting & Power Company (Texas), Lake Arrowhead Village, Inc. (Florida), Lehigh Utilities, Inc. (Florida), Louisiana Gas Service Company, Jasmine Lakes Utilities Corporation (Florida), Mad Hatter Utilities, Inc. (Florida), Marco Island Utilities, Inc. (Florida), Mountain States Telephone and Telegraph Company (Arizona), Nevada Bell Telephone Company, North Fort Myers Utilities, Inc. (Florida), Southern Bell Telephone and Telegraph Company (Florida, Louisiana and Georgia), Southern States Utilities, Inc. (Florida), Sprint of Nevada, St. George Island Utilities Company, Ltd. (Florida), Puget Sound Power & Light Company (Washington), and Texas Utilities Electric Company.

I have also testified before the Public Utility Regulation Board of El Paso, concerning the development of class cost-of-service studies and the recovery and allocation of the corporate overhead costs of Southern Union Gas Company and before the National Association of Securities Dealers concerning the market value of utility bonds purchased in the wholesale market.

Q. **HAVE YOU BEEN ACCEPTED AS AN EXPERT IN THESE JURISDICTIONS?**

A. Yes.

Q. **HAVE YOU PUBLISHED ANY ARTICLES IN THE FIELD OF PUBLIC UTILITY REGULATION?**

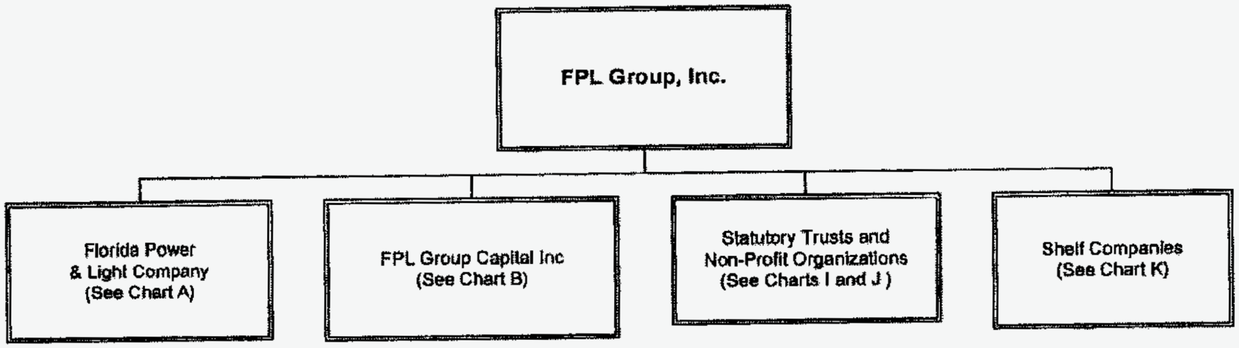
A. Yes, I have published two articles: "Affiliate Transactions: What the Rules Don't Say", Public Utilities Fortnightly, August 1, 1994 and "Electric M&A: A Regulator's Guide" Public Utilities Fortnightly, January 1, 1996.

Florida Power & Light Company
Organizational Chart

Source: FPL 2008 Diversification Report.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI **EXHIBIT** 192
COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Kimberly H. Dismukes (KHD-2)
DATE 08/31/09

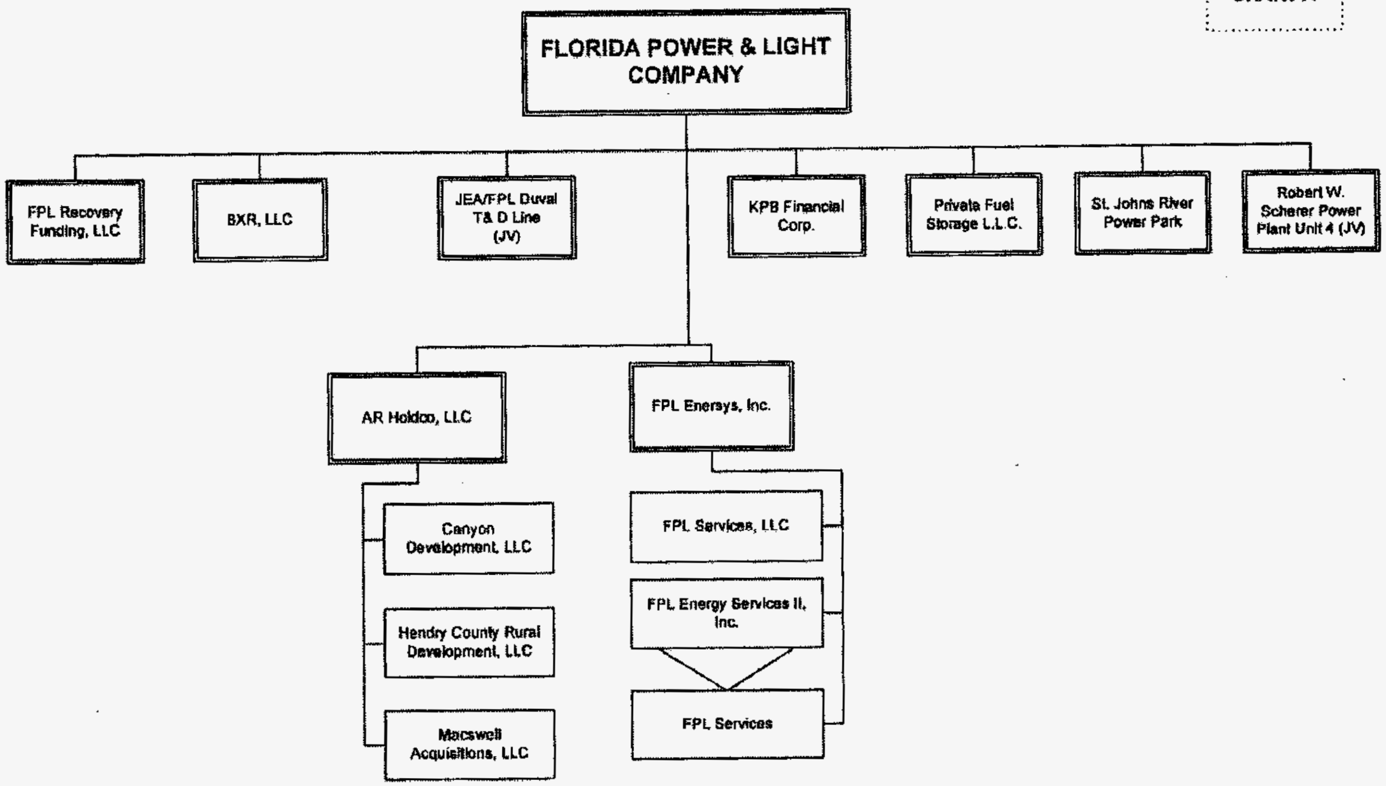
FPL Group, Inc.
Affiliate and Subsidiary Organization Chart
(02/28/2009)



454 - 1

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

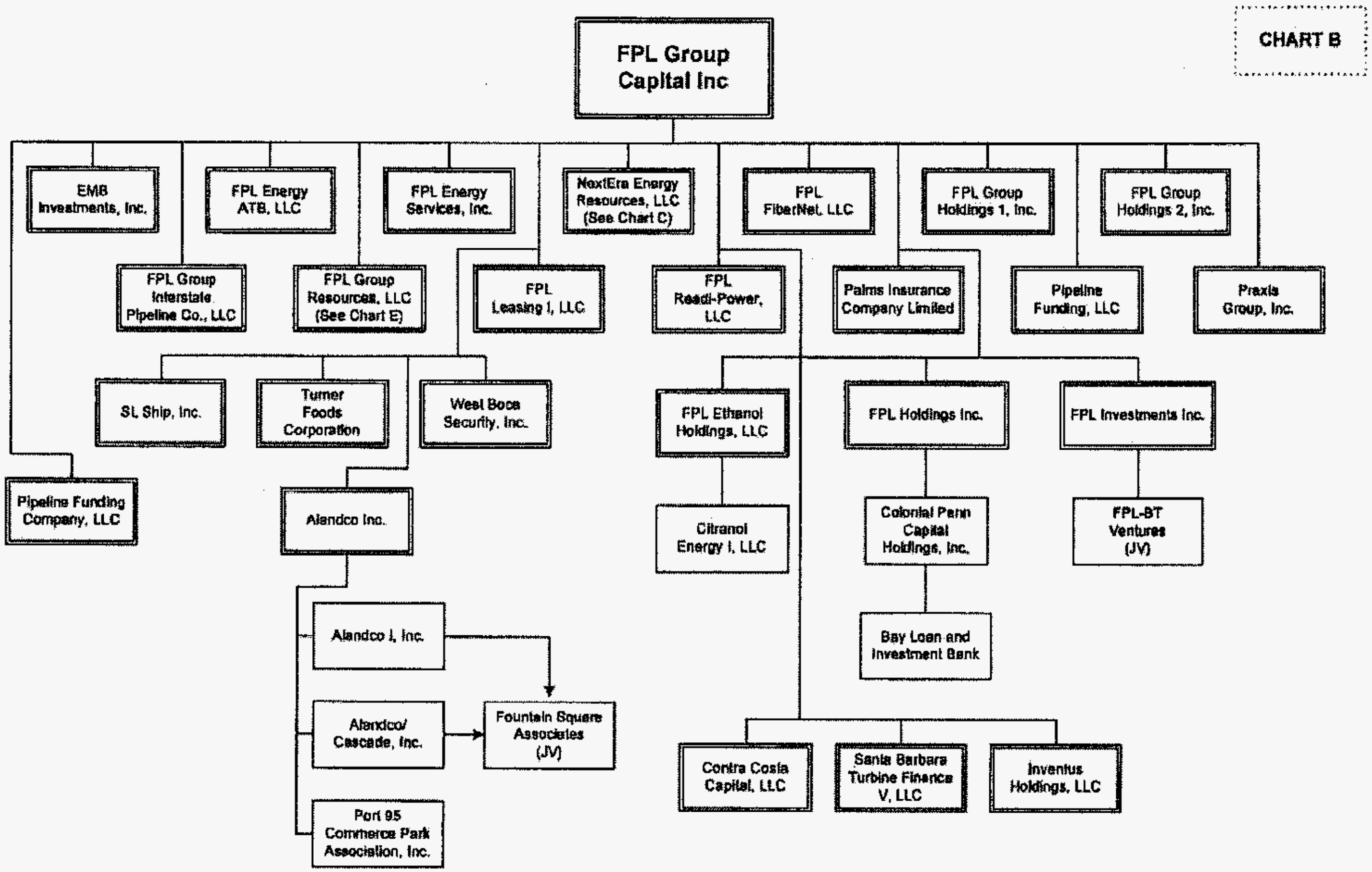
CHART A



454 - 2

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

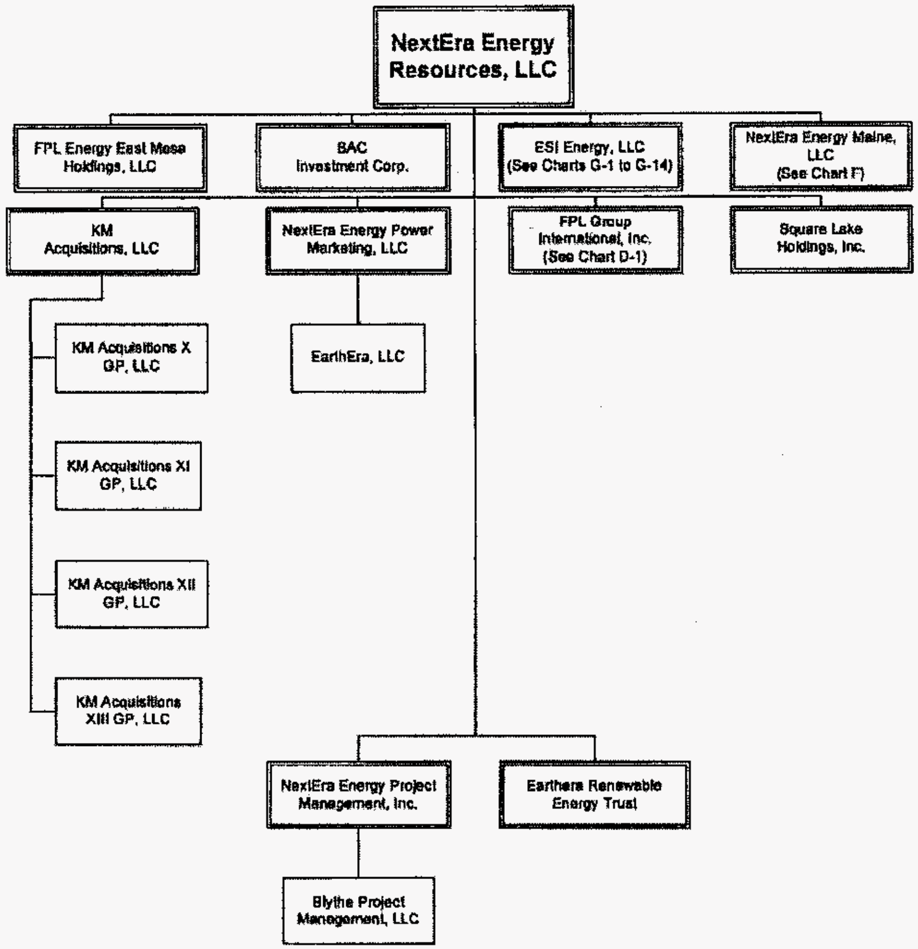
Docket Nos. 080677-EI & 090130-EI
FPL Group Organization Chart
Exhibit KHD-2, Page 4 of 27



454-3

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

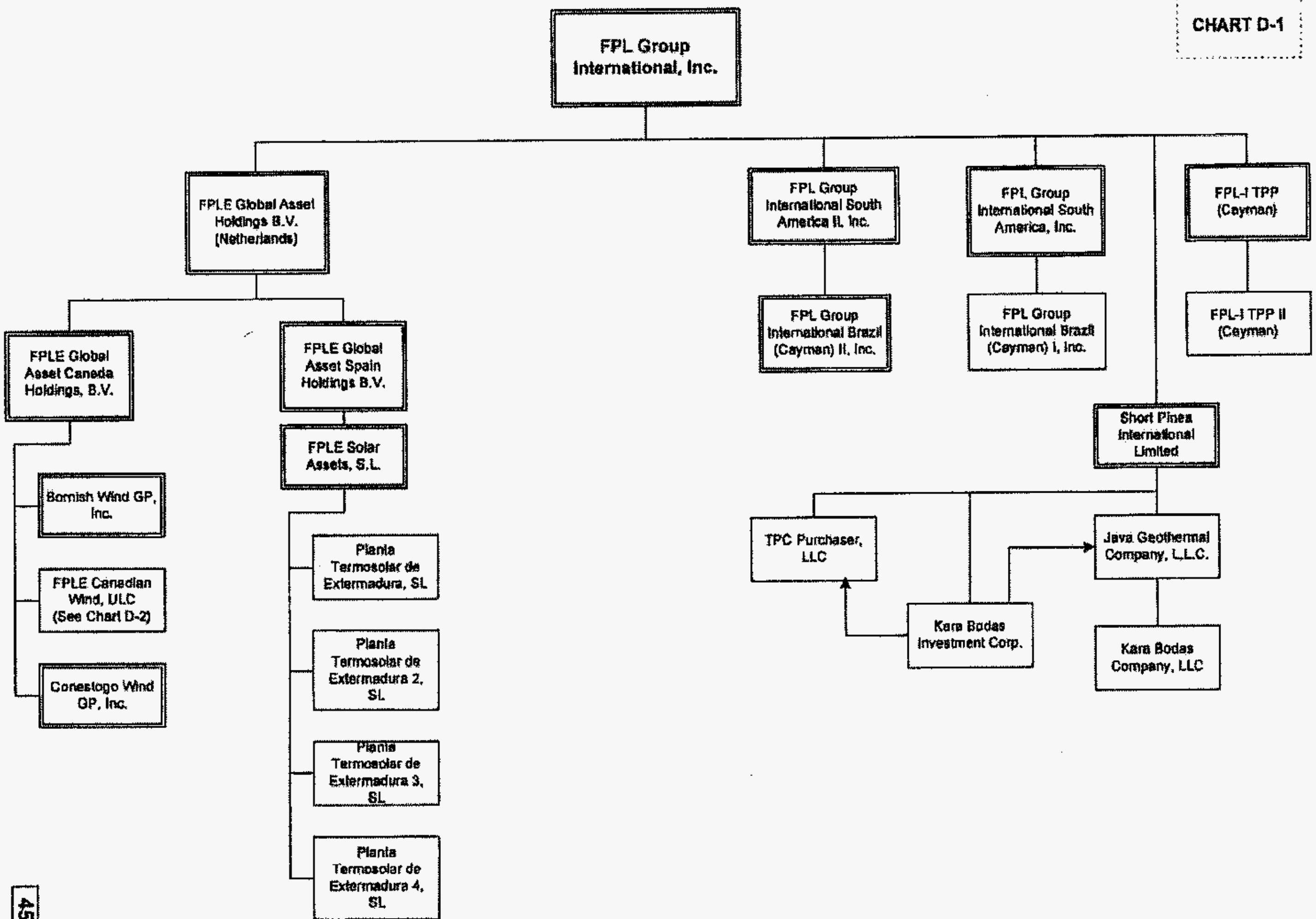
CHART C



454 - 4

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

CHART D-1

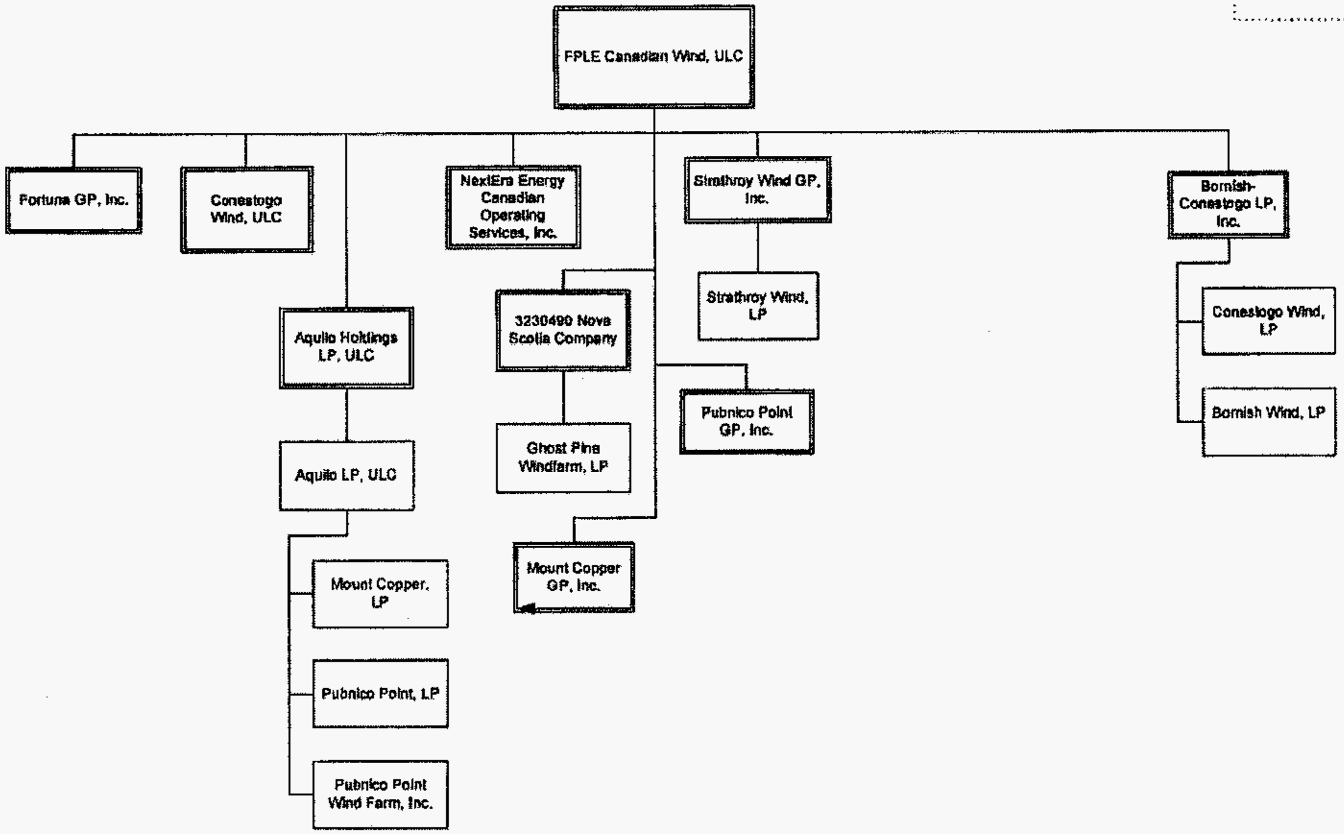


454 - 5

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Docket Nos. 080677-EI & 090130-EI
FPL Group Organization Chart
Exhibit KHD-2, Page 7 of 27

CHART D-2

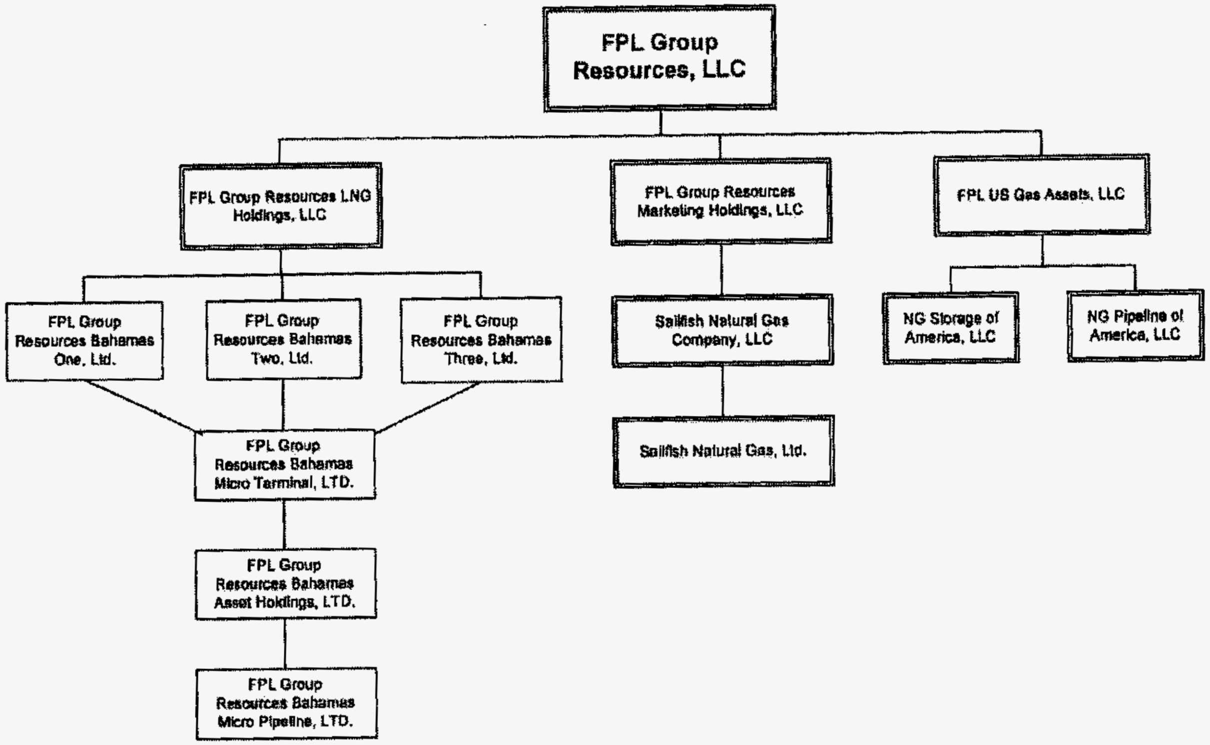


454 - 6

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Docket Nos. 080677-EI & 090130-EI
FPL Group Organization Chart
Exhibit KHD-2, Page 8 of 27

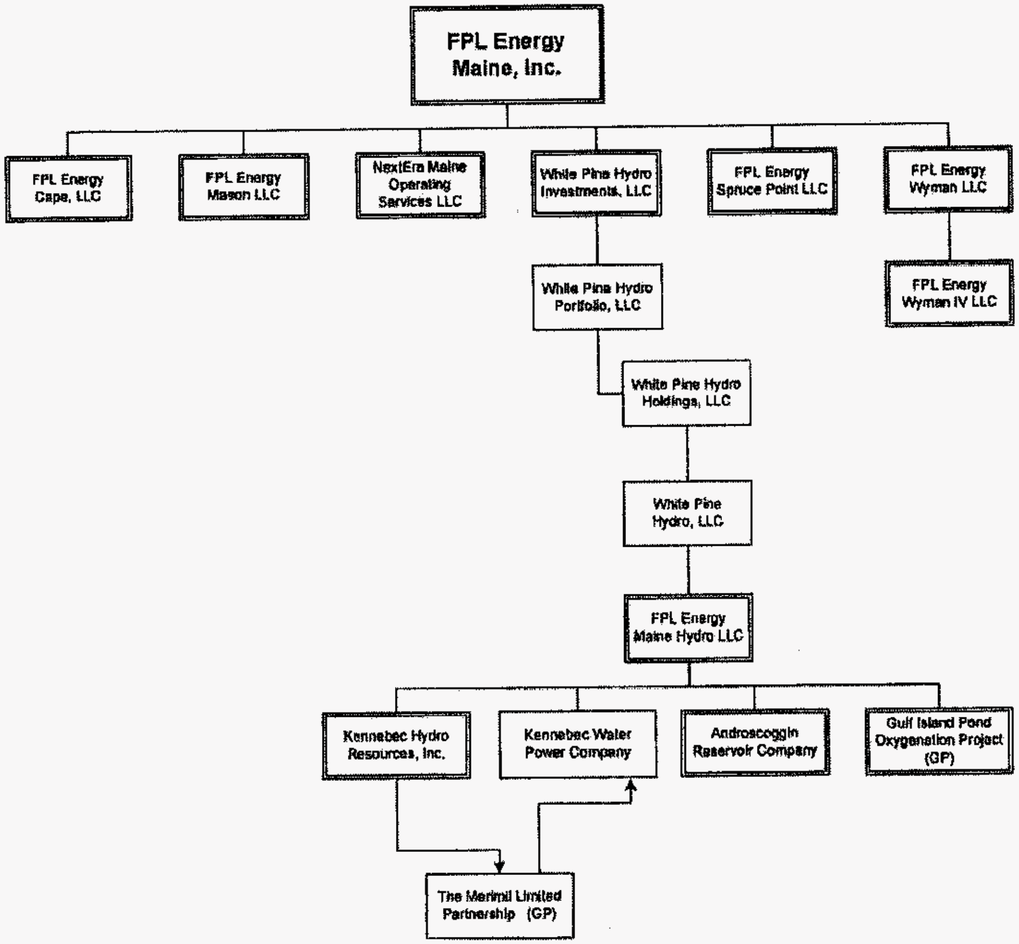
CHART E



454 - 7

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

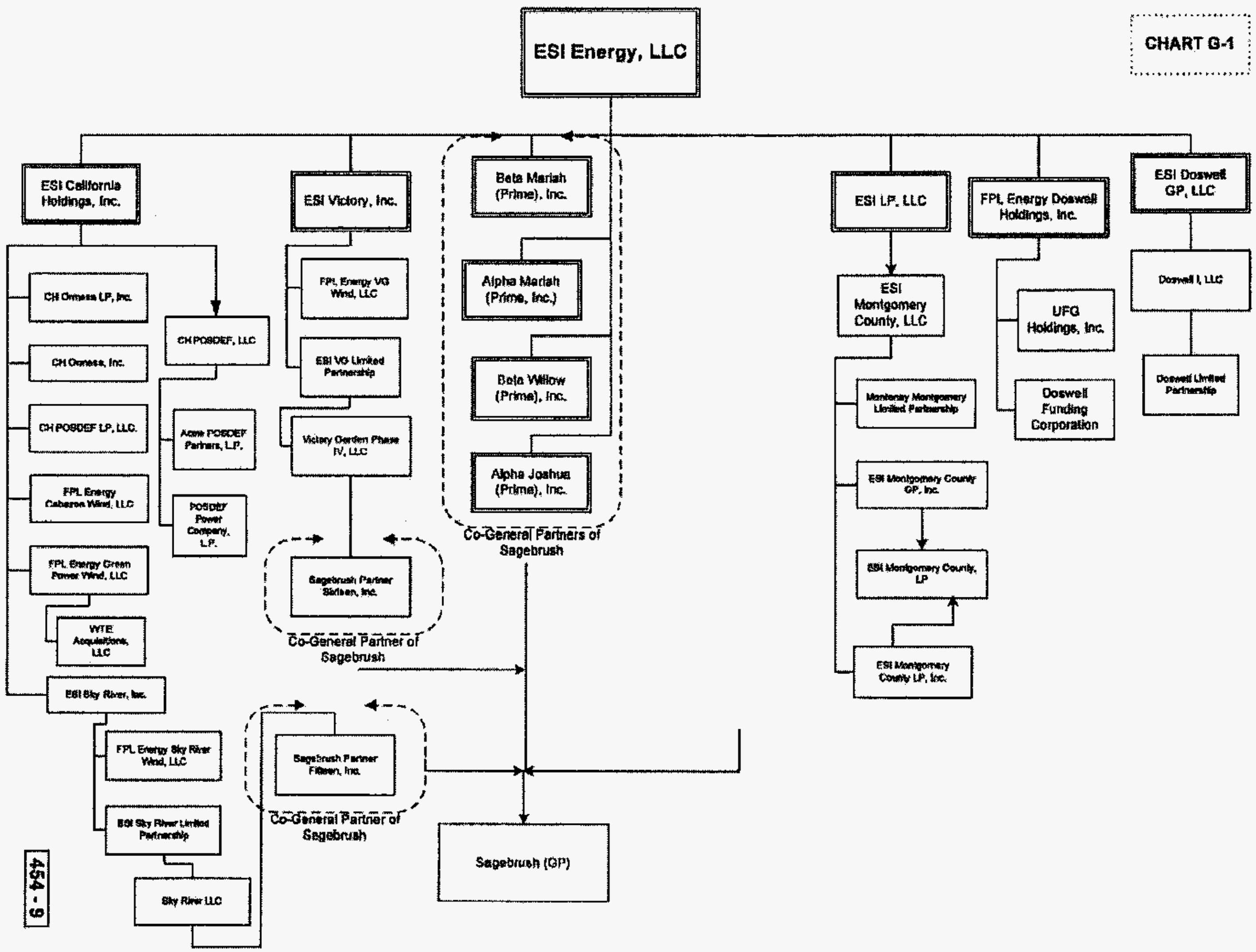
CHART F



454 - 8

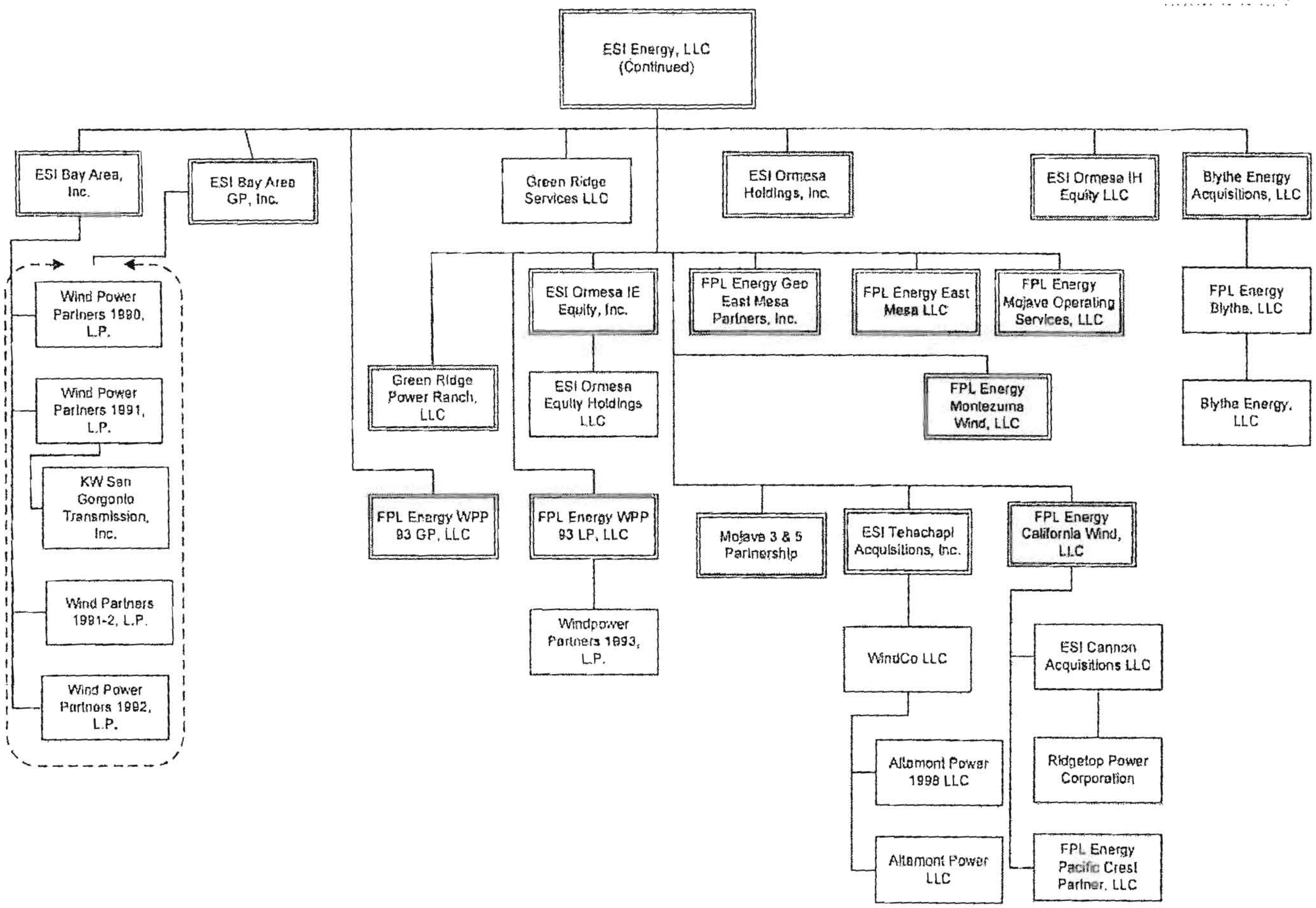
LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Docket Nos. 080677-EI & 090130-EI
FPL Group Organization Chart
Exhibit KHD-2, Page 10 of 27



LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

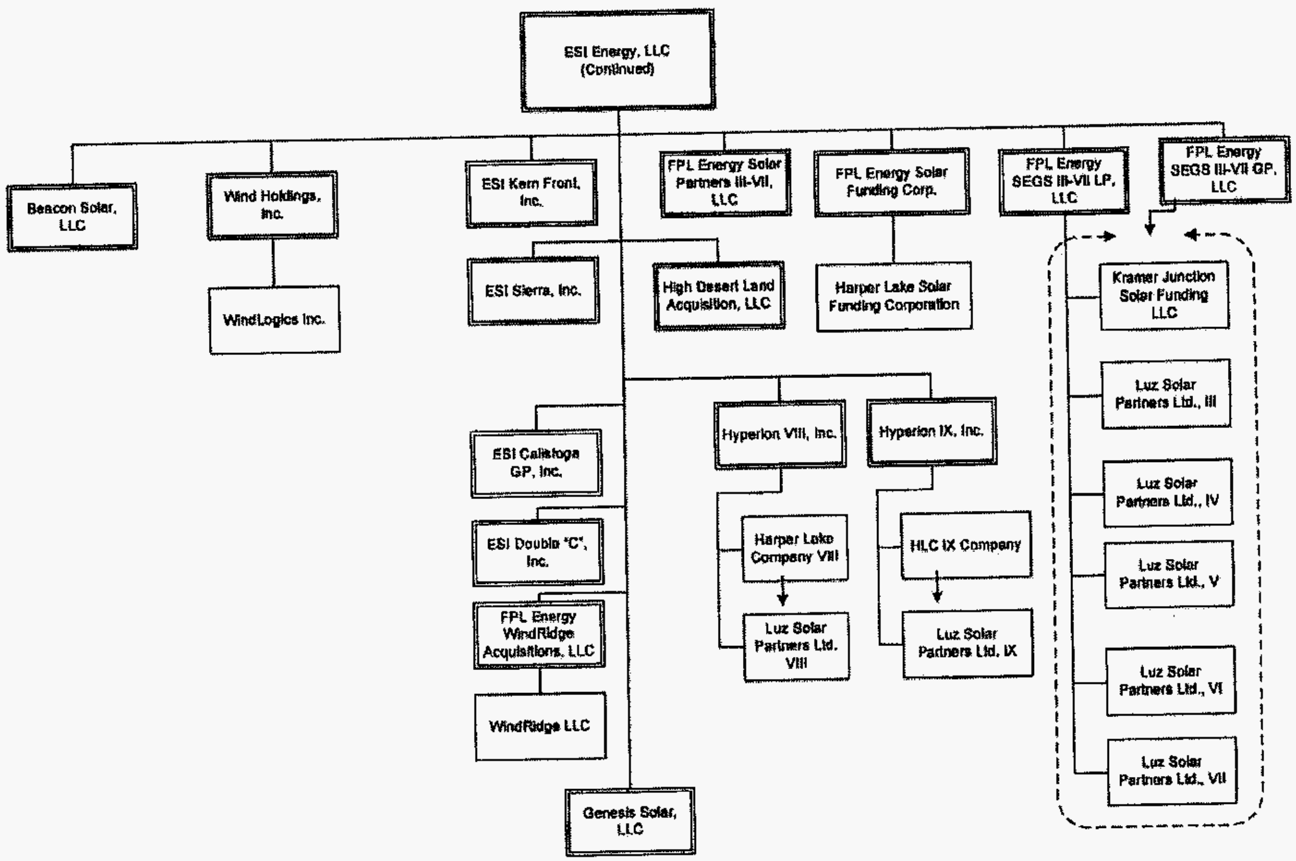
CHART G-2



454 - 10

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

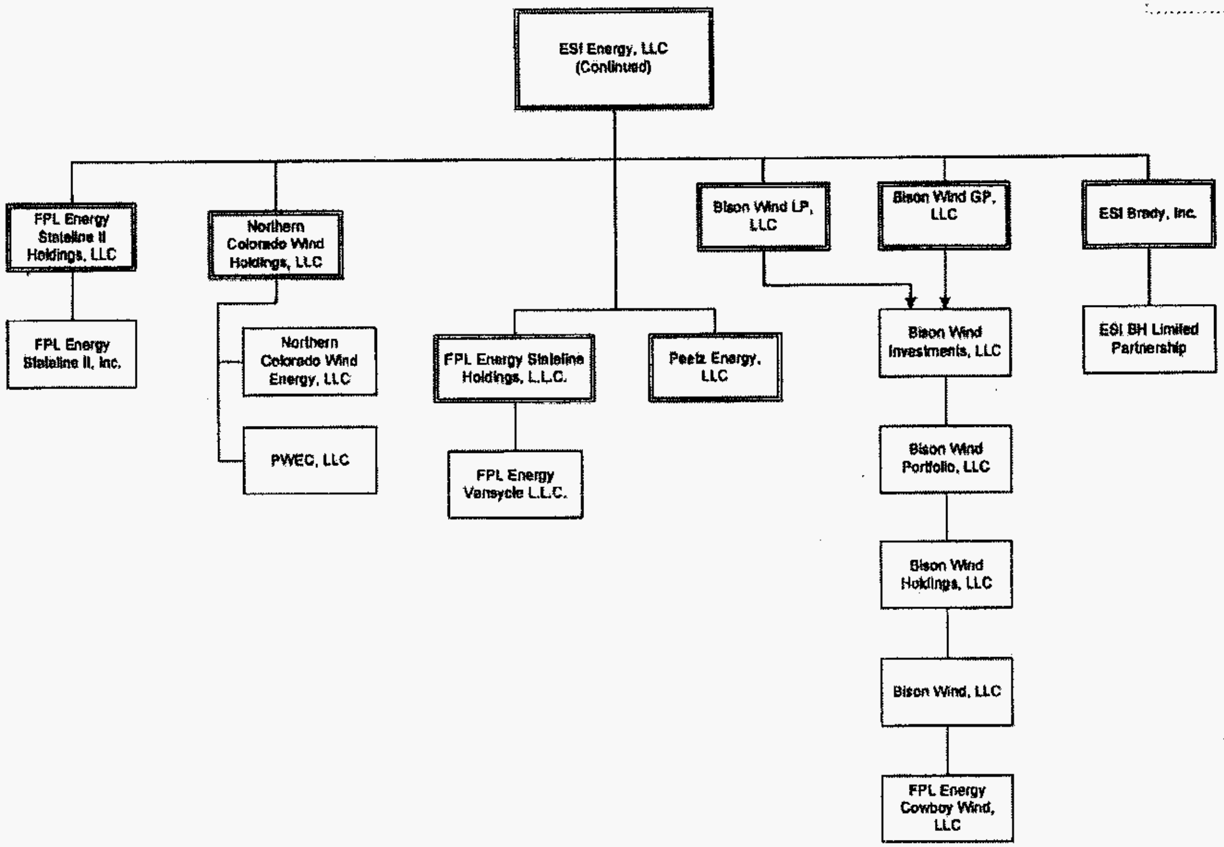
Chart G-3



454 - 11

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

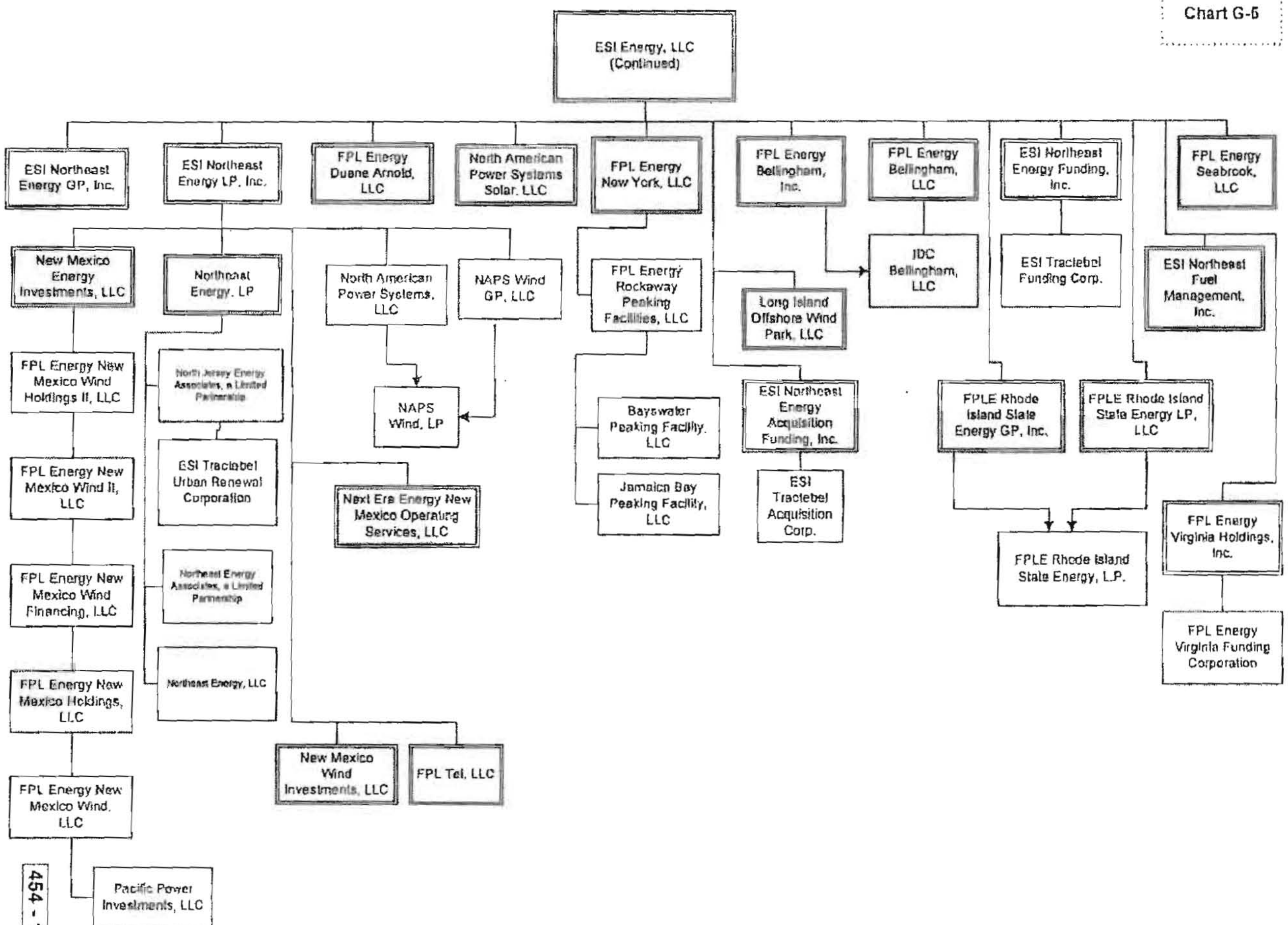
Chart G-4



454 - 12

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

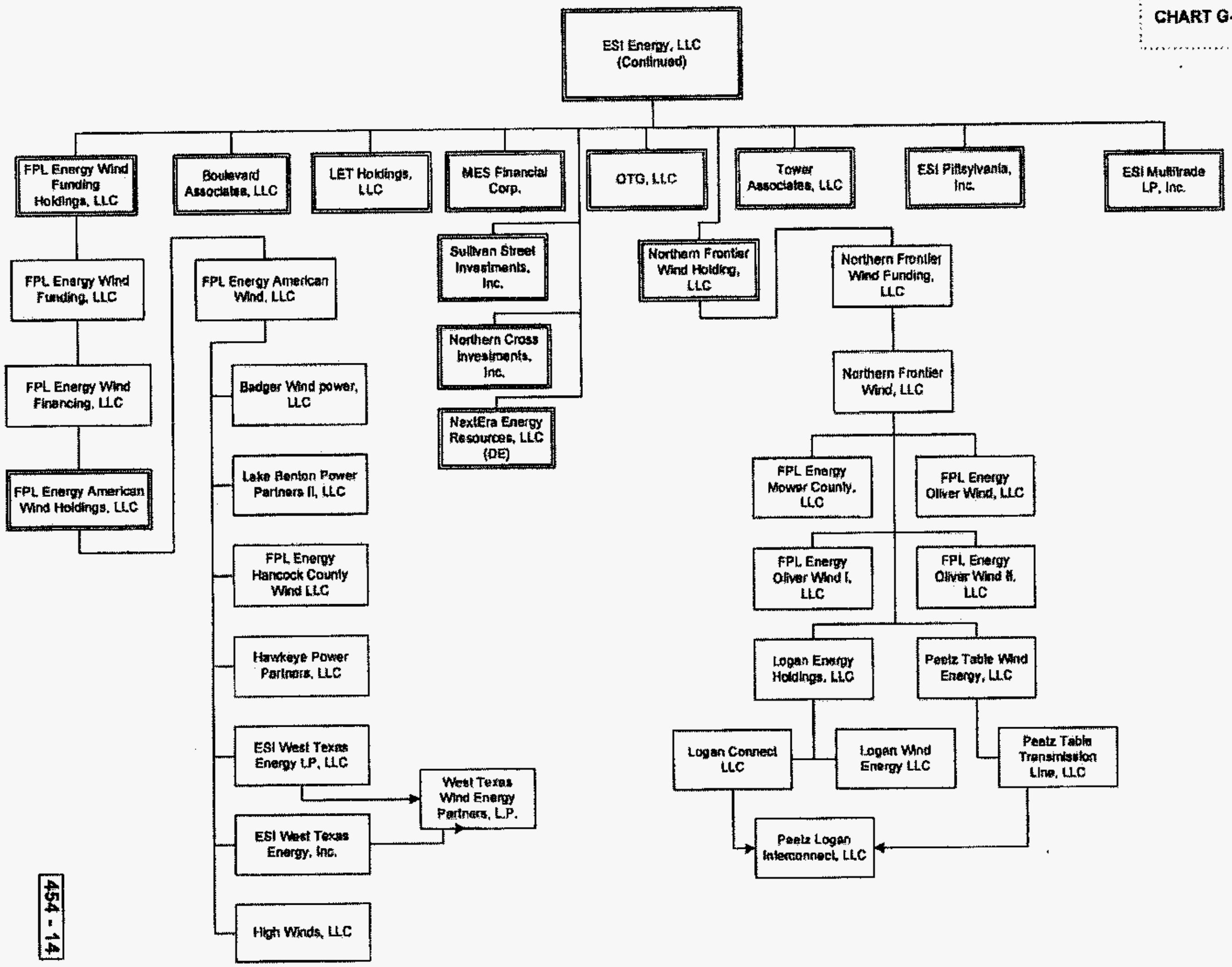
Chart G-5



454 - 13

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

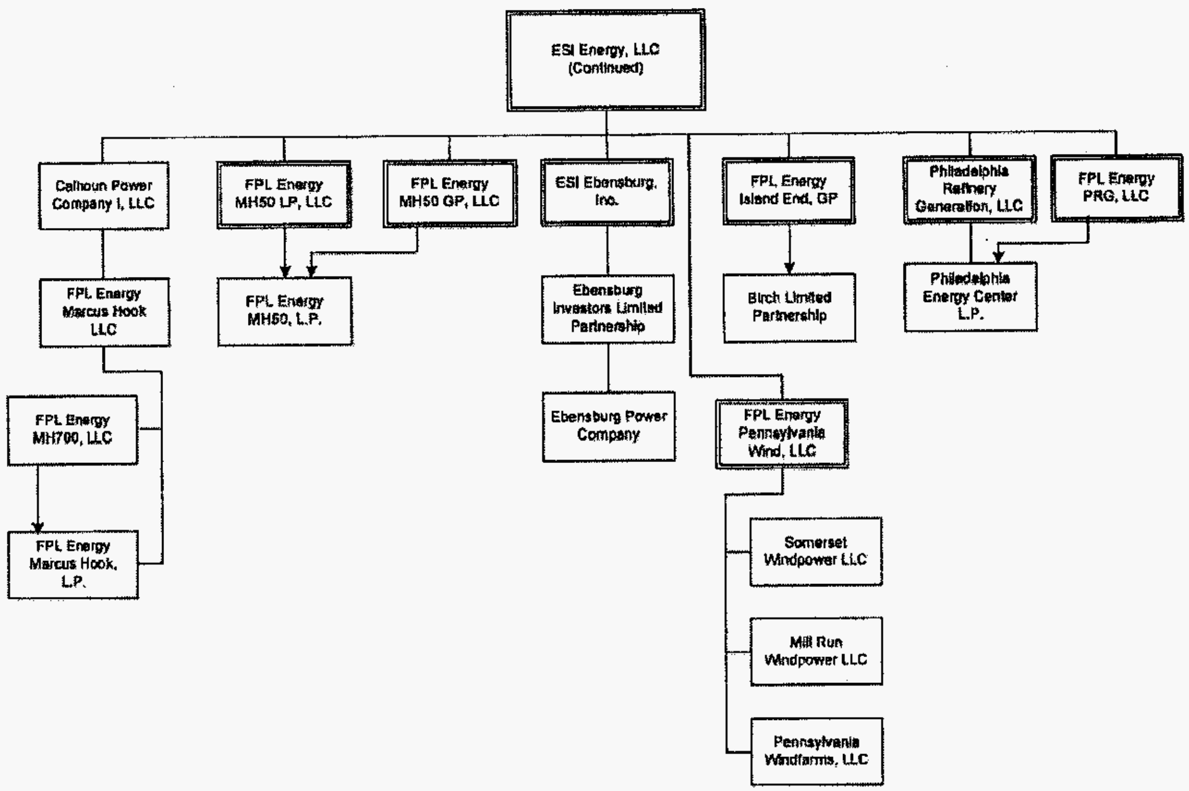
CHART G-6



454 - 14

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

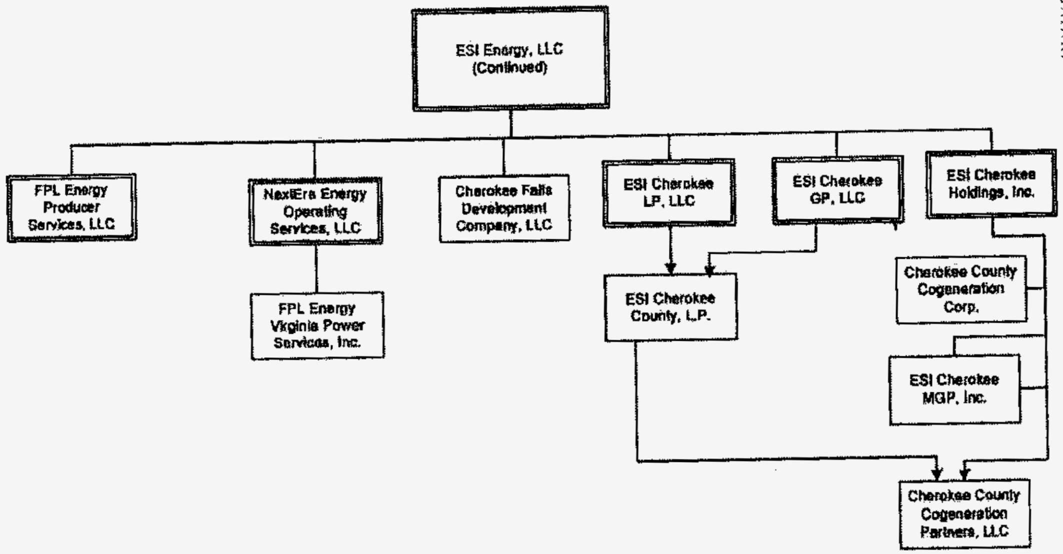
Chart G-7



454 - 15

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

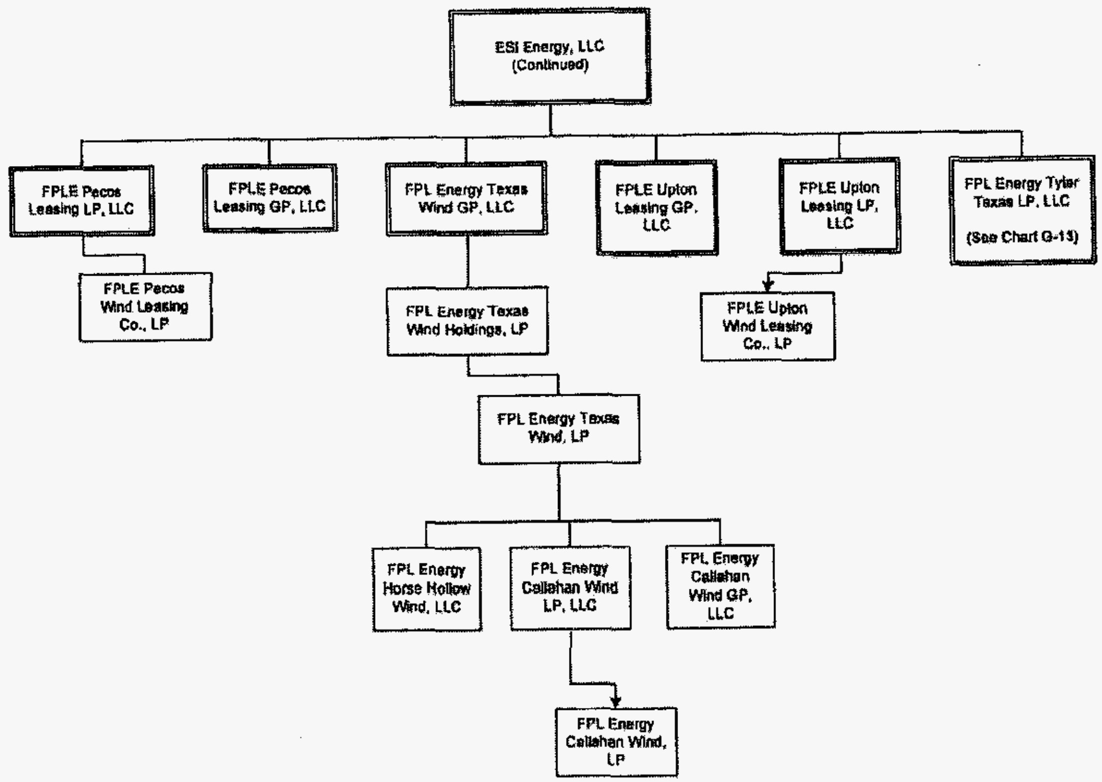
CHART G-8



454 - 16

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

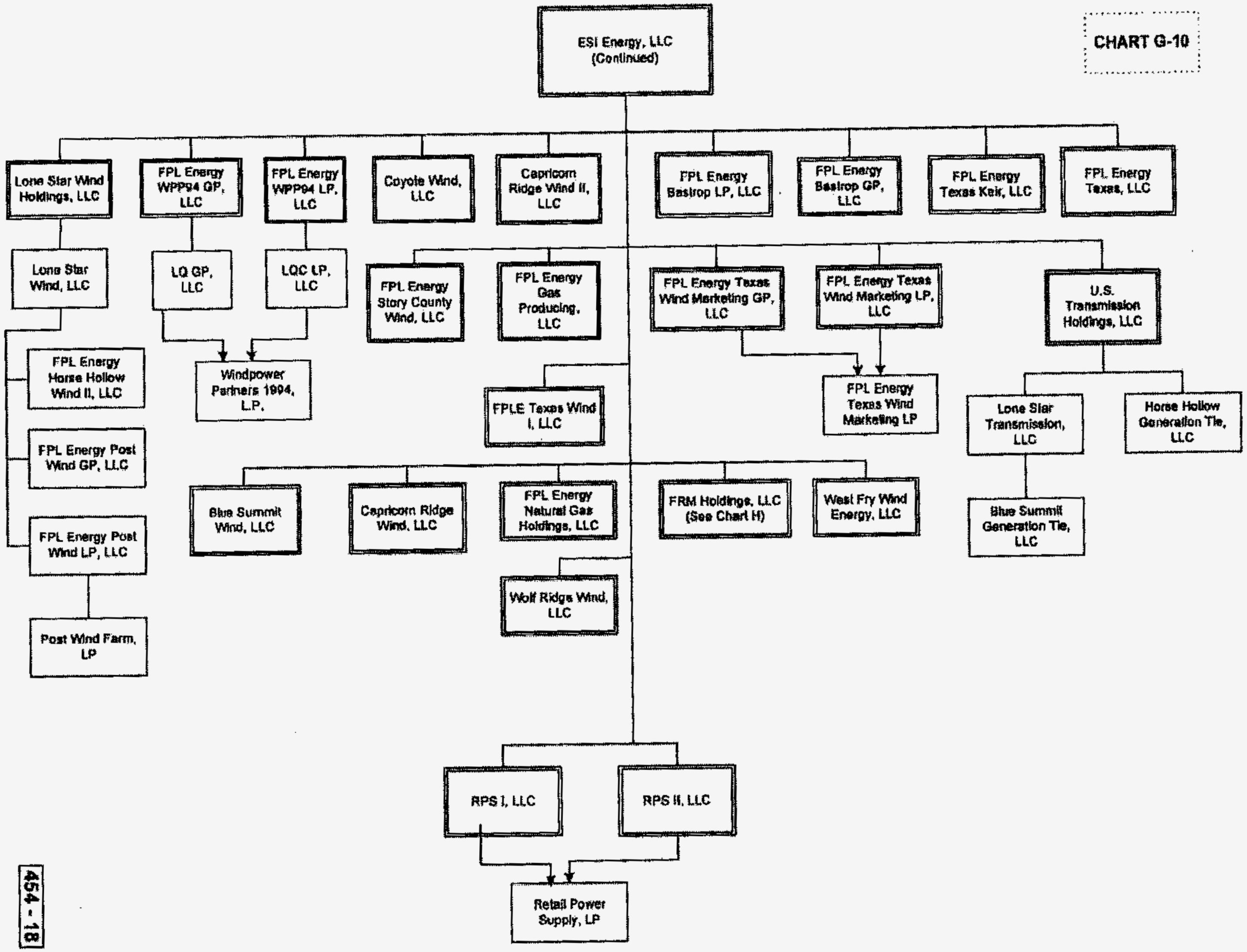
CHART G-9



454 - 17

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

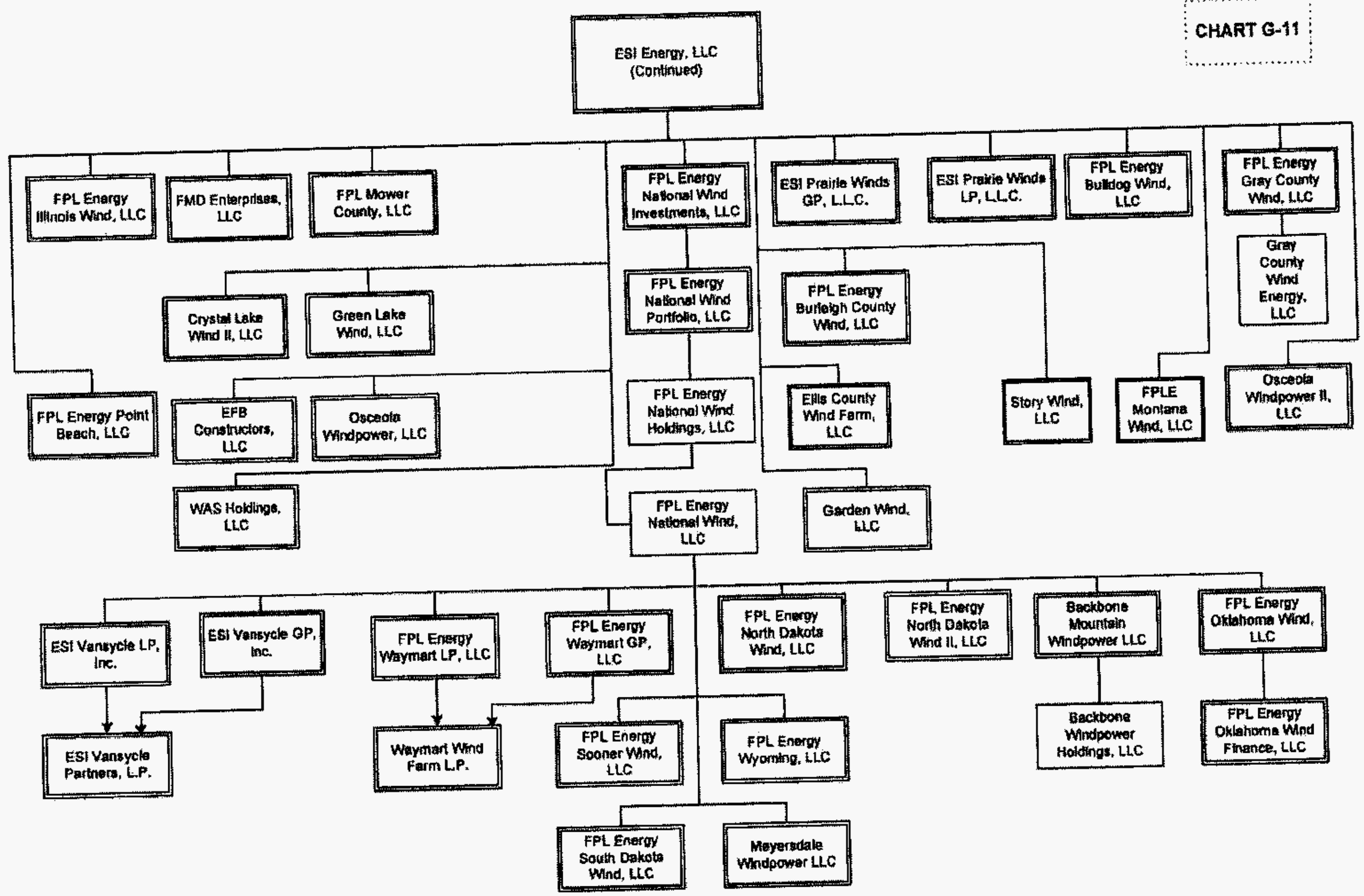
Docket Nos. 080677-EI & 090130-EI
FPL Group Organization Chart
Exhibit KHD-2, Page 19 of 27



454 - 18

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

CHART G-11

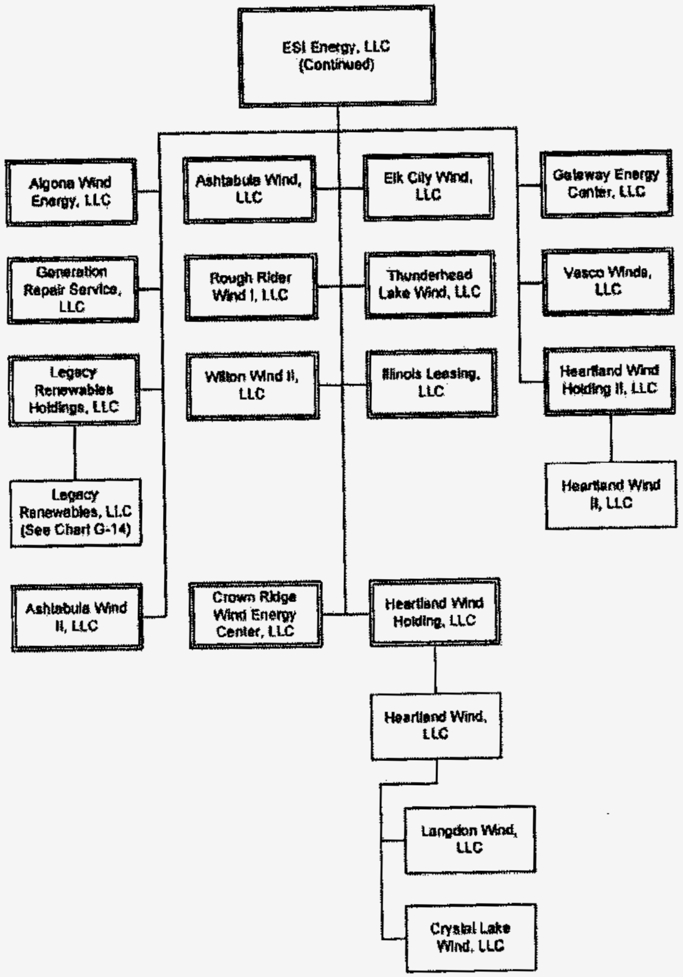


454 - 19

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Docket Nos. 080677-EI & 090130-EI
FPL Group Organization Chart
Exhibit KHD-2, Page 21 of 27

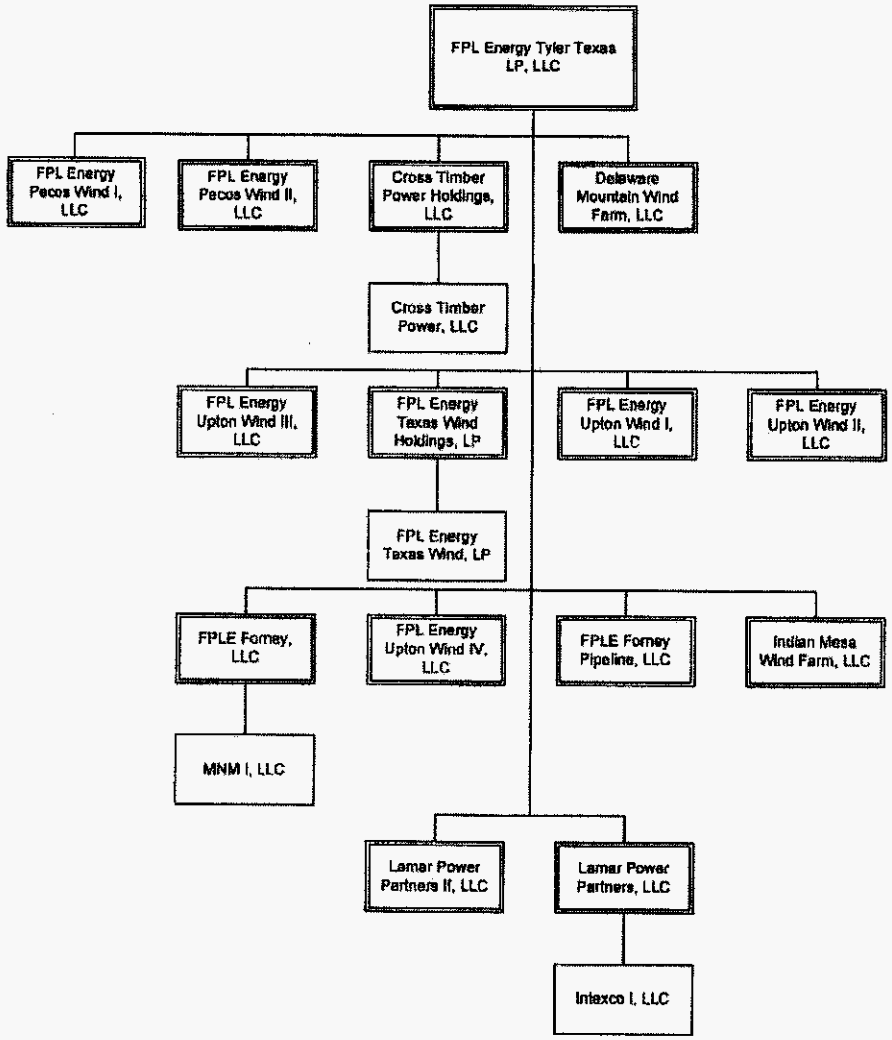
CHART G-12



454 - 20

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

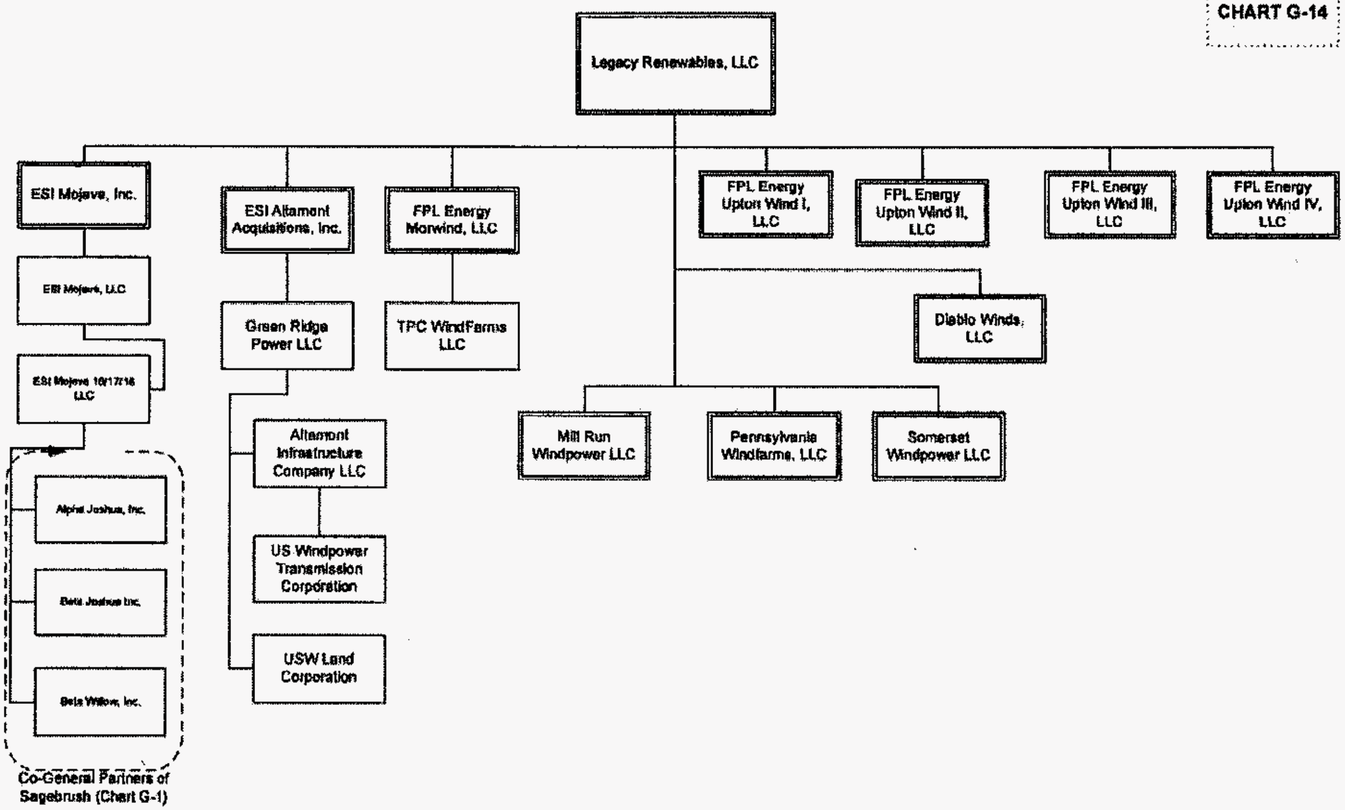
CHART G-13



454 - 21

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

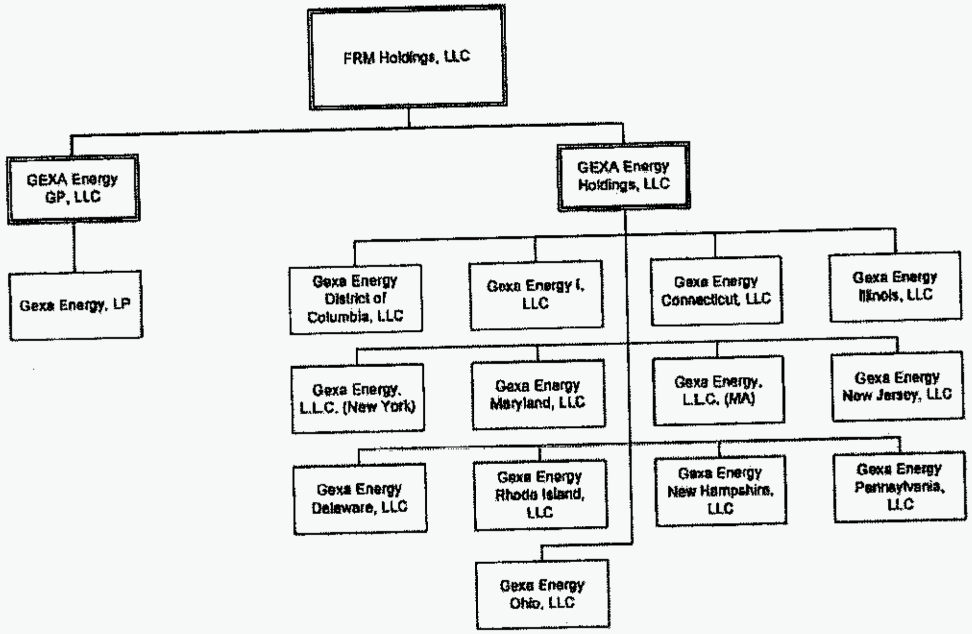
CHART G-14



454 - 22

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

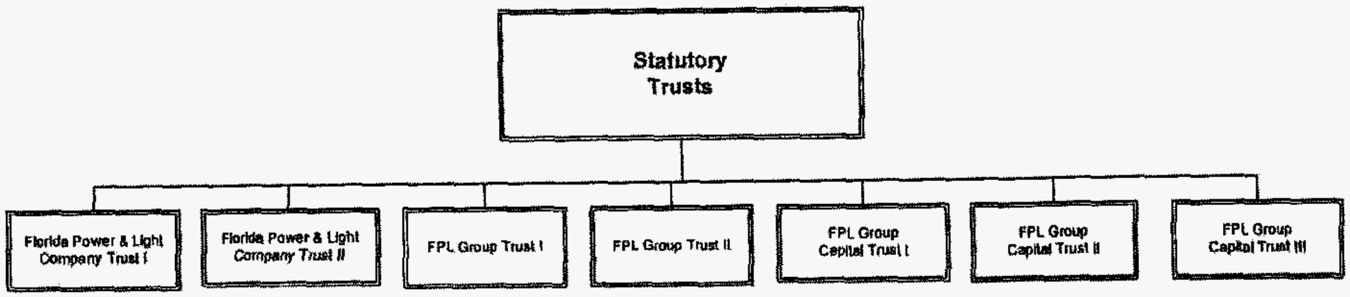
CHART H



454 - 23

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

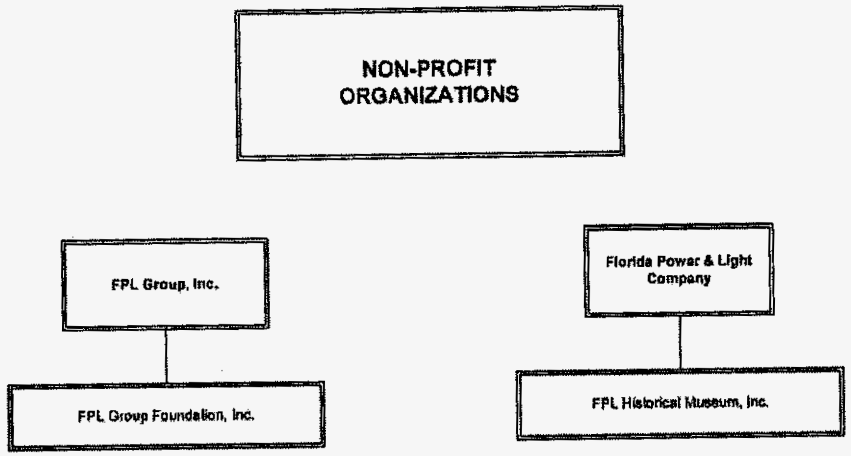
CHART I



454 - 24

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

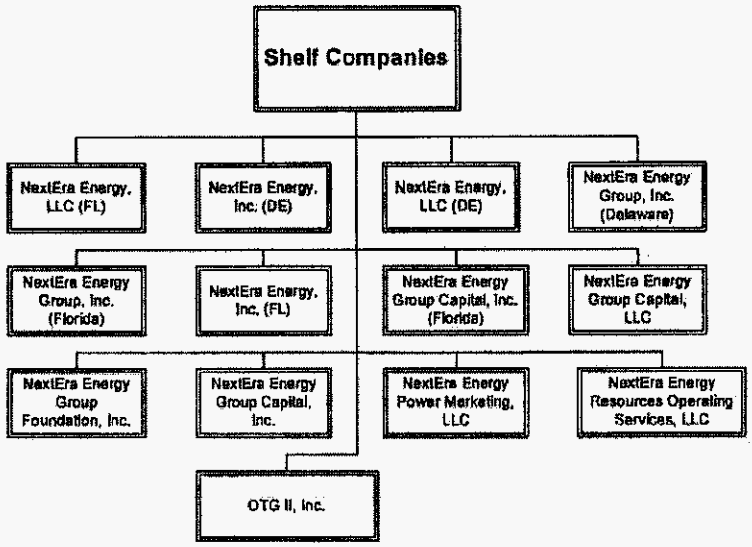
CHART J



464 - 25

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

CHART K



454 - 26

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Docket Nos. 080677-EI & 090130-EI
FPL Affiliate Growth
Exhibit KHD-3, Page 1

REDACTED

Florida Power & Light Company
FPL Affiliate Growth

	(in millions)				Percent of Total			
	2005	2006	2007	2008	2005	2006	2007	2008
Revenues:	[redacted]							
FPL Utility								
FPL NED								
Total FPL Utility								
FPL Energy/NextEra								
FPL Energy w/ OSI								
Seabrook								
Duane Arnold								
Point Beach								
Total FPLE/NextEra								
Fibernet								
FPL ES								
Palms Insur.								
Readi Power								
PP&E Ending:								
FPL Utility								
FPL NED								
Total FPL Utility								
FPL Energy/NextEra								
FPL Energy w/ OSI								
Seabrook								
Duane Arnold								
Point Beach								
Total FPLE/NextEra								
Fibernet								
FPL ES								
Readi Power								
Payroll:								
FPL Utility								
FPL NED								
Total FPL Utility								
FPL Energy/NextEra								
FPL Energy w/ OSI								
Seabrook								
Duane Arnold								
Point Beach								
Total FPLE/NextEra								
Fibernet								
FPL ES								
Readi Power								

Source: Response to OPC Document Request 106; SFHHA Interrogatory 296.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 193
COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Kimberly H. Dismukes (KHD-3)
DATE 08/31/09

Docket Nos. 080677-EI & 090130-EI
FPL Direct Charges to Affiliates
Exhibit KHD-4, Page 1

REDACTED

Florida Power & Light Company
Direct Charges to Affiliates

	Direct Charges from AG ROG 74 Excluding Affiliate Fees			Percent Change	
	2006	2007	2008	2007	2008
NextEra	[redacted]			32.69%	53.53%
Seabrook	[redacted]			45.95%	227.17%
Duane Arnold	[redacted]			111.44%	-0.60%
Point Beach	[redacted]				1616.92%
FiberNet	[redacted]			26.79%	9.40%
FPL Group Capital	[redacted]			51.93%	-29.39%
FPLES	[redacted]			16.59%	62.07%
Alandco	[redacted]			-6.08%	-48.39%
FPL Group	[redacted]			77.13%	-91.16%
FPL-NED	[redacted]			24.19%	19.99%
FPL Group International	[redacted]			1.66%	-33.36%
North American Power Systems	[redacted]			-23.00%	-11.68%
Readi-Power	[redacted]			-62.52%	-52.32%
Total	[redacted]			40.23%	37.84%

	Direct Charges from MFR Backup Excluding Affiliate Fees	Percent Change		
		2009	2010	2011
NextEra	[redacted]	-46.33%	3.58%	3.37%
Seabrook	[redacted]	-5.66%	5.39%	5.28%
Duane Arnold	[redacted]	-17.27%	4.97%	4.87%
Point Beach	[redacted]	-68.61%	5.88%	5.72%
FiberNet	[redacted]	-82.70%	3.08%	3.64%
FPL Group Capital	[redacted]	-19.17%	5.60%	1.38%
Other [1]	[redacted]	-100.00%		
FPLES	[redacted]		2.75%	2.68%
Palms Insurance	[redacted]		1.99%	2.10%
Alandco	[redacted]		1.13%	1.00%
Total	[redacted]	-41.55%	3.87%	3.02%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 194
COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Kimberly H. Dismukes (KHD-4)
DATE 08/31/09

[1] Other includes the following: Palms Insurance, FPL Group, ALANDCO, FPL Energy Services, FPL Gas Resources; NE Gas & Electric Sales, FPL New England Division, North American Power Supply, and FPL Readi Power.

Source: Response to Response to AG Interrogatory 74; OPC Interrogatory 14; OPC Document Request 12; OPC Document Request 106.

REDACTED

Florida Power & Light Company
FPL Massachusetts Formula

Affiliate	Revenues 2009 Forecast	Percent	Gross PP&E 2009 Forecast	Percent	Total Payroll 2009 Forecast	Percent	Average Percent
FPL Utility	[redacted]						
FPL NED							
FPL Energy							
Seabrook							
Duane Arnold							
Point Beach							
Fibernet							
FPL ES							
Palms Insur.							
Readi Power							
Total							

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 195
COMPANY Office ofPublic Counsel (OPC) (Direct)
WITNESS Kimberly H. Dismukes (KHD-5)
DATE 08/31/09

REDACTED

Florida Power & Light Company
FPL Massachusetts Formula

Affiliate	Revenues 2010 Forecast	Percent	Gross PP&E 2010 Forecast	Percent	Total Payroll 2010 Forecast	Percent	Average Percent
FPL Utility	[redacted]						
FPL NED							
FPL Energy							
Seabrook							
Duane Arnold							
Point Beach							
Fibernet							
FPL ES							
Palms Insur.							
Readi Power							
Total							

REDACTED

Florida Power & Light Company
FPL Massachusetts Formula

Affiliate	Revenues 2011 Forecast	Percent	Gross PP&E 2011 Forecast	Percent	Total Payroll 2011 Forecast	Percent	Average Percent
FPL Utility	[redacted]						
FPL NED							
FPL Energy							
Seabrook							
Duane Arnold							
Point Beach							
Fibernet							
FPL ES							
Palms Insur.							
Readi Power							
Total							

Source: Response to OPC Document Request 106; SFHHA Interrogatory 296.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 09 0172 EI
FLORIDA POWER & LIGHT COMPANY

IN RE: FLORIDA POWER & LIGHT COMPANY'S PETITION TO DETERMINE NEED FOR FLORIDA ENERGYSECURE LINE

PETITION
APPENDIX "B"

LIST OF ALL COMPANY OFFICERS, ADDRESSES/PHONE NUMBERS & ALL CORPORATE AFFILIATIONS

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 196
COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Kimberly H. Dismukes (KHD-6)
DATE 08/31/09

FLORIDA POWER & LIGHT COMPANY

Affiliation of Officers & Directors

Name/Address/Phone	Title(s)	Affiliations
Lewis Hay, III 700 Universe Blvd. Juno Beach, FL 33408	Director Chairman of the Board	FPL Energy Maine, Inc., Director, Chairman of the Board FPL Group Capital Inc, Director, President and Chief Executive Officer FPL Group Foundation, Inc., Director and Chairman of the Board FPL Group, Inc., Director, Chairman of the Board and Chief Executive Officer NextEra Energy Maine, LLC, Chairman NextEra Energy Resources, LLC, Chairman Turner Foods Corporation, Director
James L. Robo 700 Universe Blvd. Juno Beach, FL 33408	Director	Contra Costa Capital, LLC, Vice President FPL Group Capital Inc, Director, Vice President FPL Group Foundation, Inc., Director FPL Group Resources Bahamas Asset Holdings, LTD., Director, President FPL Group Resources Bahamas Micro Pipeline, LTD., Director, President FPL Group Resources Bahamas Micro Terminal, LTD., Director, President FPL Group Resources Bahamas One, LTD., Director, President FPL Group Resources Bahamas Three, LTD., Director, President FPL Group Resources Bahamas Two, LTD., Director, President FPL Group Resources LNG Holdings, LLC, President FPL Group Resources Marketing Holdings, LLC, President FPL Group, Inc., President and Chief Operating Officer FPL Investments Inc, Director, President Inventus Holdings, LLC, President Sailfish Natural Gas Company, LLC, Vice President
Armando J. Olivera	Director, President and Chief Executive Officer	BXR, LLC, President FPL Group Foundation, Inc., Director, President and Treasurer
Armando J. Pimentel, Jr.	Director, Ex. Vice President, Finance & Chief Financial Officer	Contra Costa Capital, LLC, Vice President FPL Group, Inc., Ex. Vice President, Finance & Chief Financial Officer FPL Group Capital Inc, Director, Senior Vice President, Finance & Chief Financial Officer Inventus Holdings, LLC, Vice President Palms Insurance Company Limited, George Town, Cayman Islands, Director FPL Recovery Funding LLC, President
Antonio Rodriguez	Director, Ex. Vice President, Power Generation Division	FPL Energy Canadian Operating Services, Inc., Director, President FPL Energy Virginia Power Services, Inc., Director, President FPL Group, Inc., Ex. Vice President, Power Generation Division FPL Historical Museum, Inc., Director and President NextEra Energy Operating Services, LLC, President

Name/Address/Phone	Title(s)	Affiliations
John A. Stall 700 Universe Blvd. Juno Beach, FL 33408	Director, Ex. Vice President, Nuclear Division	FPL Group, Inc., President, Nuclear Division
Edward F. Tancer 700 Universe Blvd. Juno Beach, FL 33408	Director, Vice Chairman & Senior Vice President, Governmental Affairs-State, Asst. Secretary	Alandco I, Inc., Director, Secretary Alandco Inc., Director, Secretary Alandco/Cascade, Inc., Director, Secretary Colonial Penn Capital Holdings, Inc., Director, President and Secretary FPL Energy Services II, Inc., Director FPL FiberNet, LLC, Secretary FPL Group Capital Inc, Asst. Secretary FPL Group Foundation, Inc., Director FPL Group Holdings 1, Inc., Director, President and Secretary FPL Group Holdings 2, Inc., Director, President and Secretary FPL Group, Inc., Asst. Secretary FPL Holdings Inc, Director, President and Secretary FPL Recovery Funding LLC, Secretary Pipeline Funding, LLC, Secretary Praxis Group, Inc., Director, President and Secretary Turner Foods Corporation, Director, President and Secretary West Boca Security, Inc., Asst. Secretary
Robert L. McGrath 700 Universe Blvd. Juno Beach, FL 33408	Ex. Vice President, Engineering, Construction & Corporate Services	FPL Energy Callahan Wind GP, LLC, Vice President FPL Energy MH700, LLC, Vice President, FPL Group, Inc., Ex. Vice President, Engineering, Construction & Corporate Services NextEra Energy Resources, LLC, Vice President
James W. Poppell 700 Universe Blvd. Juno Beach, FL 33408	Ex. Vice President, Human Resources, Asst. Secretary	Calypso U.S. Pipeline, LLC, Vice President FPL Group Interstate Pipeline Co., LLC, President FPL Group, Inc., Ex. Vice President, Human Resources, Asst. Secretary
Charles E. Sieving 700 Universe Blvd. Juno Beach, FL 33408	Ex. Vice President and General Counsel	FPL Group, Inc., Ex. Vice President and General Counsel
Manoochehr K. Nazar 700 Universe Blvd. Juno Beach, FL 33408	Senior Vice President and Nuclear Chief Operating Officer	FPL Energy Duane Arnold, LLC, Vice President FPL Energy Point Beach, LLC, Vice President FPL Energy Seabrook, LLC, Senior Vice President & Chief Nuclear Officer FPL Group, Inc., Chief Nuclear Officer

Name/Address/Phone	Title(s)	Affiliations
Adalberto Alfonso 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Distribution	None
Craig W. Arcari 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Power Generation Technical Services	None
Alissa E. Ballot 700 Universe Blvd. Juno Beach, FL 33408	Vice President & Corporate Secretary	FPL Energy Services, Inc., Secretary FPL Energy Services II, Inc., Secretary FPL Enersys, Inc., Secretary FPL Group, Inc., Vice President & Corporate Secretary FPL Group Capital Inc, Secretary FPL Services, LLC, Secretary FPL Group Foundation, Inc., Secretary Inventus Holdings, LLC, Secretary
Robert E. Barrett, Jr. 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Finance	None
Deborah H. Caplan 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Integrated Supply Chain	None
Lakshman Charanjiva 700 Universe Blvd. Juno Beach, FL 33408	Vice President and Chief Information Officer	None
K. Michael Davis 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Accounting & Chief Accounting Officer	FPL Group, Inc., Controller & Chief Accounting Officer FPL Group Capital Inc, Controller & Chief Accounting Officer FPL Recovery Funding LLC, Chief Accounting Officer
Timothy Fitzpatrick 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Marketing & Communications	None

Name/Address/Phone	Title(s)	Affiliations
Sam A. Forrest 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Energy Marketing & Trading	None
Martin Gettler 700 Universe Blvd. Juno Beach, FL 33408	Vice President, New Nuclear Projects	None
Donald Grissette 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Nuclear Operations, South Region	None
Paul W. Hamilton 700 Universe Blvd. Juno Beach, FL 33408	Vice President, State Legislative Affairs	None
G. Keith Hardy 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Power Generation Operations	None
James P. Higgins 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Tax	BAC Investments Corp., Director BXR, LLC, Treasurer EMB Investments, Inc., Director, Vice President FPL Energy Virginia Funding Corporation, Director FPL Group, Inc., Vice President, Tax FPL Group Capital Inc, Vice President KPB Financial Corp., Director, Vice President MES Financial Corp., Director, Vice President Northern Cross Investments, Inc., Director Square Lake Holdings, Inc., Director Sullivan Street Investments, Inc., Director UFG Holdings, Inc., Director West Boca Security, Inc., Director, Vice President
William Jefferson, Jr. 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Turkey Point Nuclear Power Plant	None

Name/Address/Phone	Title(s)	Affiliations
Gordon L. Johnston 700 Universe Blvd. Juno Beach, FL 33408	Vice President, St. Lucie Nuclear Power Plant	None
Terry O. Jones 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Nuclear Operations, Midwest Region	None
James A. Keener 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Transmission and Substation	None
Rajiv S. Kundalkar 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Nuclear Power Uprate	FPL Energy Point Beach, LLC, Vice President FPL Energy Seabrook, LLC, Vice President
Randall R. LaBauve 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Environmental Services	None
R. W. Litchfield 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Regulatory Affairs and Chief Regulatory Officer	None
Susan A. Mellans 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Human Resources	None
C. Martin Mennes 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Transmission Operations & Planning	None
Pamela M. Rauch 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Corporate & External Affairs	None

Name/Address/Phone	Title(s)	Affiliations
Marlene Santos 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Customer Service	FPL Energy Services, Inc., Director, President FPL Energy Services II, Inc., Director, President FPL Enersys, Inc., Director, President FPL Services, LLC, President
Eric E. Silagy 700 Universe Blvd. Juno Beach, FL 33408	Vice President and Chief Development Officer	None
Mark E. Warner 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Nuclear Plant Support	None
Michael M. Wilson 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Governmental Affairs - Federal	FPL Group, Inc., Vice President, Governmental Affairs – Federal

Name/Address/Phone	Title(s)	Affiliations
William L. Yeager 700 Universe Blvd. Juno Beach, FL 33408	Vice President, Engineering and Construction	Algona Wind Energy, LLC, Vice President Ashtabula Wind II, LLC, Vice President Ashtabula Wind, LLC, Vice President Beacon Solar, LLC, Vice President Blythe Energy, LLC, Vice President Capricorn Ridge Wind II, LLC, Vice President Capricorn Ridge Wind, LLC, Vice President Coyote Wind, LLC, Vice President Crowned Ridge Wind Energy Center, LLC, Vice President EFB Constructors, LLC, Vice President Elk City Wind, LLC, Vice President FPL Energy Montezuma Wind, LLC, Vice President FPL Energy Natural Gas Holdings, LLC, Vice President FPL Energy Oliver Wind II, LLC, Vice President FPL Energy Point Beach, LLC, Vice President FPL Energy Texas Wind Marketing GP, LLC, Vice President FPLE Montana Wind, LLC, Vice President Gateway Energy Center, LLC, Vice President Genesis Solar, LLC, Vice President Horse Hollow Generation Tie, LLC, Vice President Lamar Power Partners II, LLC, Vice President Langdon Wind, LLC, Vice President NextEra Energy Resources, LLC, Asst. Secretary Northern Colorado Wind Energy, LLC, Vice President Osceola Windpower II, LLC, Vice President Osceola Windpower, LLC, Vice President Peetz Energy, LLC, Vice President Peetz Logan Interconnect, LLC, Vice President Peetz Table Transmission Line, LLC, Vice President Peetz Table Wind Energy, LLC, Vice President Rough Rider Wind I, LLC, Vice President Thunderhead Lake Wind, LLC, Vice President Vasco Winds, LLC, Vice President WAS Holdings, LLC, Vice President West Fry Wind Energy, LLC, Vice President Wolf Ridge Wind, LLC, Vice President

Name/Address/Phone	Title(s)	Affiliations
Paul I. Cutler 700 Universe Blvd. Juno Beach, FL 33408	Treasurer and Asst. Secretary	Alandco I, Inc., Treasurer Alandco Inc., Treasurer Alandco/Cascade, Inc., Treasurer Aquilo Holdings LP, ULC, Vice President Aquilo LP, ULC, Vice President Ashtabula Wind, LLC, Vice President, Assistant Treasurer Backbone Mountain Windpower LLC, Vice President, Treasurer Backbone Windpower Holdings, LLC, Vice President, Treasurer Badger Windpower, LLC, Vice President, Treasurer Bayswater Peaking Facility, LLC, Vice President, Treasurer Bison Wind Holdings, LLC, Vice President, Treasurer Bison Wind Investments, LLC, Vice President, Treasurer Bison Wind Portfolio, LLC, Vice President, Treasurer Bison Wind, LLC, Vice President, Treasurer Calhoun Power Company I, LLC, Vice President Colonial Penn Capital Holdings, Inc., Director, Vice President, Treasurer Conestogo Wind, ULC, Vice President Cross Timber Power Holding, LLC, Vice President, Treasurer Cross Timber Power, LLC, Vice President, Treasurer Crystal Lake Wind, LLC, Vice President, Asst. Treasurer Diablo Winds, LLC, Vice President Doswell I, LLC, Treasurer ESI Doswell GP, LLC, Treasurer ESI Energy, LLC, Treasurer ESI LP, LLC, Treasurer ESI Mojave LLC, Vice President ESI Vansycle GP, Inc., Vice President, Treasurer ESI Vansycle LP, Inc., Vice President, Treasurer ESI West Texas Energy LP, LLC, Vice President, Treasurer ESI West Texas Energy, Inc., Vice President, Treasurer Florida Power & Light Company Trust II, Administrative Trustee FPL Energy American Wind Holdings, LLC, Vice President, Treasurer FPL Energy American Wind, LLC, Vice President, Treasurer FPL Energy Burleigh County Wind, LLC, Vice President, Treasurer FPL Energy Canadian Operating Services, Inc., Vice President FPL Energy Cowboy Wind, LLC, Vice President, Treasurer FPL Energy Hancock County Wind, LLC, Vice President, Treasurer FPL Energy Horse Hollow Wind II, LLC, Vice President, Treasurer FPL Energy Horse Hollow Wind, LLC, Vice President, Treasurer FPL Energy Maine Hydro LLC, Vice President FPL Energy Marcus Hook LLC, Vice President FPL Energy MH700, LLC, Vice President FPL Energy Morwind, LLC, Vice President FPL Energy National Wind Holdings, LLC, Vice President, Treasurer FPL Energy National Wind Investments, LLC, Vice President, Treasurer FPL Energy National Wind Portfolio, LLC, Vice President, Treasurer

Name/Address/Phone	Title(s)	Affiliations
Cutler (Continued)		FPL Energy National Wind, LLC, Vice President, Treasurer FPL Energy New Mexico Holdings, LLC, Vice President, Treasurer FPL Energy New Mexico Wind Financing, LLC, Vice President, Treasurer FPL Energy New Mexico Wind Holdings II, LLC, Vice President, Treasurer FPL Energy New Mexico Wind II, LLC, Vice President, Treasurer FPL Energy New Mexico Wind, LLC, Vice President, Treasurer FPL Energy New York, LLC, Vice President, Treasurer FPL Energy North Dakota Wind II, LLC, Vice President, Treasurer FPL Energy North Dakota Wind, LLC, Vice President, Treasurer FPL Energy Oklahoma Wind Finance, LLC, Vice President, Treasurer FPL Energy Oklahoma Wind, LLC, Vice President, Treasurer FPL Energy Post Wind GP, LLC, Vice President, Treasurer FPL Energy Post Wind LP, LLC, Vice President, Treasurer FPL Energy Rockaway Peaking Facilities, LLC, Vice President FPL Energy SEGS III-VII GP, LLC, Vice President FPL Energy SEGS III-VII LP, LLC, Vice President FPL Energy Services II, Inc., Treasurer and Asst. Secretary FPL Energy Services, Inc., Treasurer FPL Energy Sooner Wind, LLC, Vice President, Treasurer FPL Energy South Dakota Wind, LLC, Vice President, Treasurer FPL Energy Stateline Holdings, L.L.C., Vice President, Treasurer FPL Energy Stateline II Holdings, LLC, Vice President, Treasurer FPL Energy Stateline II, Inc., Vice President, Treasurer FPL Energy Texas Wind GP, LLC, Vice President, Treasurer FPL Energy Tyler Texas LP, LLC, Vice President, Treasurer FPL Energy Upton Wind I, LLC, Vice President FPL Energy Upton Wind II, LLC, Vice President FPL Energy Upton Wind III, LLC, Vice President FPL Energy Upton Wind IV, LLC, Vice President FPL Energy Vansycle L.L.C., Vice President FPL Energy Waymart GP, LLC, Vice President, Treasurer FPL Energy Waymart LP, LLC, Vice President, Treasurer FPL Energy Wind Financing, LLC, Vice President, Treasurer FPL Energy Wind Funding Holdings, LLC, Vice President, Treasurer FPL Energy Wind Funding, LLC, Vice President, Treasurer FPL Energy Wyoming, LLC, Vice President, Treasurer NextEra Energy Resources, LLC, Treasurer FPL Enersys, Inc., Treasurer and Asst. Secretary FPL FiberNet, LLC, Treasurer FPL Group Capital Inc, Director, Vice President, Treasurer, Asst. Secretary FPL Group Capital Trust I, Administrative Trustee FPL Group Capital Trust II, Administrative Trustee FPL Group Capital Trust III, Administrative Trustee

Name/Address/Phone	Title(s)	Affiliations
Cutler (continued)		FPL Group Holdings 1, Inc., Treasurer FPL Group Holdings 2, Inc., Treasurer FPL Group Resources Bahamas Asset Holdings, LTD., Treasurer FPL Group Resources Bahamas Micro Pipeline, LTD., Treasurer FPL Group Resources Bahamas Micro Terminal, LTD., Treasurer FPL Group Resources Bahamas One, LTD., Treasurer FPL Group Resources Bahamas Three, LTD., Treasurer FPL Group Resources Bahamas Two, LTD., Treasurer FPL Group Resources LNG Holdings, LLC, Treasurer FPL Group Resources Marketing Holdings, LLC, Treasurer FPL Group Resources, LLC, Treasurer FPL Group Trust I, Administrative Trustee FPL Group Trust II, Administrative Trustee FPL Group, Inc., Treasurer, Asst. Secretary FPL Historical Museum, Inc., Vice President and Asst. Secretary FPL Holdings Inc, Director, Vice President, Treasurer FPL Investments Inc, Director, Treasurer, Controller FPL Readi-Power, LLC, Treasurer FPL Recovery Funding LLC, Treasurer FPL Services, LLC, Treasurer FPLE Canadian Wind, ULC, Vice President Green Ridge Power LLC, Vice President Green Ridge Services LLC, Vice President Heartland Wind Holding, LLC, Vice President, Asst. Treasurer Heartland Wind, LLC, Vice President, Asst. Treasurer Heartland Wind Holding II, LLC, Vice President, Asst. Treasurer Heartland Wind II, LLC, Vice President, Asst. Treasurer High Winds, LLC, Vice President, Treasurer Inventus Holdings, LLC, Treasurer Jamaica Bay Peaking Facility, LLC, Vice President, Treasurer Langdon Wind, LLC, Vice President, Asst. Treasurer Legacy Renewables Holdings, LLC, Vice President Legacy Renewables, LLC, Vice President Lone Star Wind Holdings, LLC, Vice President, Treasurer Lone Star Wind, LLC, Vice President, Treasurer Meyersdale Windpower LLC, Vice President, Treasurer Mill Run Windpower LLC, Vice President Mount Copper GP, Inc., Vice President Northern Frontier Wind Funding, LLC, Vice President Northern Frontier Wind, LLC, Vice President Pacific Power Investments, LLC, Vice President Palms Insurance Company, Limited, Director, Treasurer Pennsylvania Windfarms, LLC, Vice President Pipeline Funding, LLC, Vice President, Treasurer Praxis Group, Inc., Treasurer

Name/Address/Phone	Title(s)	Affiliations
Cutler (continued)		Pubnico Point GP, Inc., Vice President Pubnico Point Wind Farm Inc., Vice President Santa Barbara Turbine Finance V, LLC, Vice President Sky River LLC, Vice President Somerset Windpower LLC, Vice President Story Wind, LLC, Vice President, Assistant Treasurer Turner Foods Corporation, Treasurer Victory Garden Phase IV, LLC, Vice President White Pine Hydro Holdings, LLC, Vice President White Pine Hydro Investments, LLC, Vice President White Pine Hydro Portfolio, LLC, Vice President White Pine Hydro, LLC, Vice President
Kimberly Ousdahl 700 Universe Blvd. Juno Beach, FL 33408	Controller	None

Name/Address/Phone	Title(s)	Affiliations
Kathy A. Beilhart 700 Universe Blvd. Juno Beach, FL 33408	Asst. Treasurer	Aquilo Holdings LP, ULC, Vice President, Asst. Treasurer, Asst. Secretary Aquilo LP, ULC, Vice President, Asst. Treasurer, Asst. Secretary Ashtabula Wind, LLC, Vice President, Asst. Treasurer, Asst. Secretary Backbone Mountain Windpower LLC, Vice President, Asst. Treasurer, Asst. Secretary Backbone Windpower Holdings, LLC, Vice President, Asst. Treasurer, Asst. Secretary Bison Wind Holdings, LLC, Vice President, Asst. Treasurer, Asst. Secretary Bison Wind Investments, LLC, Vice President, Asst. Treasurer, Asst. Secretary Bison Wind Portfolio, LLC, Vice President, Asst. Treasurer, Asst. Secretary Bison Wind, LLC, Vice President, Asst. Treasurer, Asst. Secretary Conestogo Wind, ULC, Vice President, Asst. Treasurer, Asst. Secretary Cross Timber Power Holding, LLC, Vice President, Asst. Treasurer, Asst. Secretary Cross Timber Power, LLC, Vice President, Asst. Treasurer, Asst. Secretary Crystal Lake Wind, LLC, Vice President, Asst. Treasurer, Asst. Secretary Diablo Winds, LLC, Vice President, Asst. Treasurer, Asst. Secretary ESI Mojave LLC, Vice President, Asst. Treasurer, Asst. Secretary ESI Vansycle GP, Inc., Vice President, Asst. Treasurer, Asst. Secretary ESI Vansycle LP, Inc., Vice President, Asst. Treasurer, Asst. Secretary Florida Power & Light Company, Asst. Treasurer FPL Energy American Wind, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Burleigh County Wind, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Canadian Operating Services, Inc., VP, Asst. Treasurer, Asst. Secretary FPL Energy Cowboy Wind, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Horse Hollow Wind II, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Horse Hollow Wind, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Maine Hydro LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Morwind, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy National Wind Holdings, LLC, Vice President, Asst. Treasurer, Asst. Secretary

Name/Address/Phone	Title(s)	Affiliations
Beilhart (continued)		FPL Energy National Wind Investments, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy National Wind Portfolio, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy National Wind, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy North Dakota Wind II, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy North Dakota Wind, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Oklahoma Wind Finance, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Oklahoma Wind, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Post Wind GP, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Post Wind LP, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Rockaway Peaking Facilities, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Sooner Wind, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy South Dakota Wind, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Texas Wind GP, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Tyler Texas LP, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Upton Wind I, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Upton Wind II, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Upton Wind III, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Upton Wind IV, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Vansycle L.L.C., Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Waymart GP, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Waymart LP, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Energy Wyoming, LLC, Vice President, Asst. Treasurer, Asst. Secretary FPL Group Capital Inc, Asst. Treasurer FPL Group, Inc., Asst. Treasurer FPL Recovery Funding LLC, Asst. Treasurer FPLE Canadian Wind, ULC, Vice President, Asst. Treasurer, Asst. Secretary Green Ridge Power LLC, Vice President, Asst. Treasurer, Asst. Secretary Green Ridge Services LLC, Vice President, Asst. Treasurer, Asst. Secretary Heartland Wind Holding, LLC, Vice President, Asst. Treasurer, Asst. Secretary Heartland Wind, LLC, Vice President, Asst. Treasurer, Asst. Secretary Heartland Wind Holding II, LLC, Vice President, Asst. Treasurer, Asst. Secretary Inventus Holdings, LLC, Asst. Treasurer Langdon Wind, LLC, Vice President, Asst. Treasurer, Asst. Secretary Legacy Renewables Holdings, LLC, Vice President, Asst. Treasurer, Asst. Secretary Legacy Renewables, LLC, Vice President, Asst. Treasurer, Asst. Secretary Lone Star Wind Holdings, LLC, Vice President, Asst. Treasurer, Asst. Secretary Lone Star Wind, LLC, Vice President, Asst. Treasurer, Asst. Secretary

Name/Address/Phone	Title(s)	Affiliations
Beilhart (continued)		Meyersdale Windpower LLC, Vice President, Asst. Treasurer, Asst. Secretary Mill Run Windpower LLC, Vice President, Asst. Treasurer, Asst. Secretary Mount Copper GP, Inc., Vice President, Asst. Treasurer, Asst. Secretary Northern Frontier Wind Funding, LLC, Vice President, Asst. Treasurer, Asst. Secretary Northern Frontier Wind, LLC, Vice President, Asst. Treasurer, Asst. Secretary Pennsylvania Windfarms, LLC, Vice President, Asst. Treasurer, Asst. Secretary Pubnico Point GP, Inc., Vice President, Asst. Treasurer, Asst. Secretary Pubnico Point Wind Farm Inc., Vice President, Asst. Treasurer, Asst. Secretary Short Pines International Limited, Asst. Treasurer Sky River LLC, Vice President, Asst. Treasurer, Asst. Secretary Story Wind, LLC, Vice President, Asst Treasurer, Asst. Secretary Somerset Windpower LLC, Vice President, Asst. Treasurer, Asst. Secretary Victory Garden Phase IV, LLC, Vice President, Asst. Treasurer, Asst. Secretary White Pine Hydro Holdings, LLC, Vice President, Asst. Treasurer, Asst. Secretary White Pine Hydro Investments, LLC, Vice President, Asst. Treasurer, Asst. Secretary White Pine Hydro Portfolio, LLC, Vice President, Asst. Treasurer, Asst. Secretary White Pine Hydro, LLC, Vice President, Asst. Treasurer, Asst. Secretary
M. Beth Farr 700 Universe Blvd. Juno Beach, FL 33408	Asst. Controller	FPL Group, Inc., Asst. Controller
Frank V. Isabell 700 Universe Blvd. Juno Beach, FL 33408	Asst. Controller	Alandco Inc., Asst. Controller ESI Energy, LLC, Asst. Secretary FPL Group Capital Inc, Asst. Controller FPL Group International, Inc., Asst. Controller FPL Group, Inc., Asst. Controller
Daisy Jacobs 700 Universe Blvd. Juno Beach, FL 33408	Asst. Controller	None

Name/Address/Phone	Title(s)	Affiliations
Judith J. Kahn 700 Universe Blvd. Juno Beach, FL 33408	Asst. Treasurer	BAC Investment Corp., Director, Treasurer Contra Costa Capital, LLC, Treasurer EMB Investments, Inc., Director, Treasurer FPL Energy American Wind Holdings, LLC, Asst. Treasurer FPL Energy American Wind, LLC, Asst. Treasurer FPL Energy Duane Arnold, LLC, Asst. Treasurer FPL Energy Point Beach, LLC, Asst. Treasurer FPL Energy Rockaway Peaking Facilities, LLC, Treasurer FPL Energy Seabrook, LLC, Asst. Treasurer FPL Energy Virginia Funding Corporation, Director, Treasurer FPL Energy Wind Funding, LLC, Asst. Treasurer FPL Group, Inc., Asst. Treasurer and Asst. Secretary KPB Financial Corp., Director, Treasurer Kramer Junction Solar Funding, LLC, Treasurer MES Financial Corp., Director, Treasurer Northern Cross Investments, Inc., Director, Treasurer Pacific Power Investments, LLC, Treasurer Pipeline Funding Company, LLC, Treasurer Santa Barbara Turbine Finance V, LLC, Treasurer Square Lake Holdings, Inc., Director, Treasurer Sullivan Street Investments, Inc., Director, Treasurer UFG Holdings, Inc., Director, Treasurer West Boca Security, Inc., Director, Treasurer
Joaquin . Leon 700 Universe Blvd. Juno Beach, FL 33408	Asst. Secretary	FPL Group, Inc., Asst. Secretary
Nancy A. Swalwell 700 Universe Blvd. Juno Beach, FL 33408	Asst. Secretary	None

Florida Power & Light Company
FPL Group Earnings Summary by Segment

(unaudited)

	2000	2001	2002	2003	2004	2005	2006	2007	2008
Adjusted Earnings per Share (assuming dilution)									
FPL	$ 1.89	$ 2.06	$ 2.07	$ 2.06	$ 2.07	$ 1.94	$ 2.02	$ 2.09	$ 1.96
NextEra	0.24	0.34	0.38	0.53	0.51	0.82	1.31	1.57	2.04
Corporate and Other	0.06	-0.02	-0.04	-0.11	-0.09	-0.13	-0.29	-0.17	-0.16
Total Adjusted Earnings per Share	**$ 2.19**	**$ 2.38**	**$ 2.41**	**$ 2.48**	**$ 2.49**	**$ 2.63**	**$ 3.04**	**$ 3.49**	**$ 3.84**
Certain Items (after-tax)	-0.12	-0.04	-1.03	0.05	-0.01	-0.29	0.19	-0.22	0.23
Total Earnings per Share	**$ 2.07**	**$ 2.34**	**$ 1.38**	**$ 2.53**	**$ 2.48**	**$ 2.34**	**$ 3.23**	**$ 3.27**	**$ 4.07**
FPL	86%	87%	86%	83%	83%	74%	66%	60%	51%
NextEra	11%	14%	16%	21%	20%	31%	43%	45%	53%
Corporate and Other	3%	-1%	-2%	-4%	-4%	-5%	-10%	-5%	-4%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%

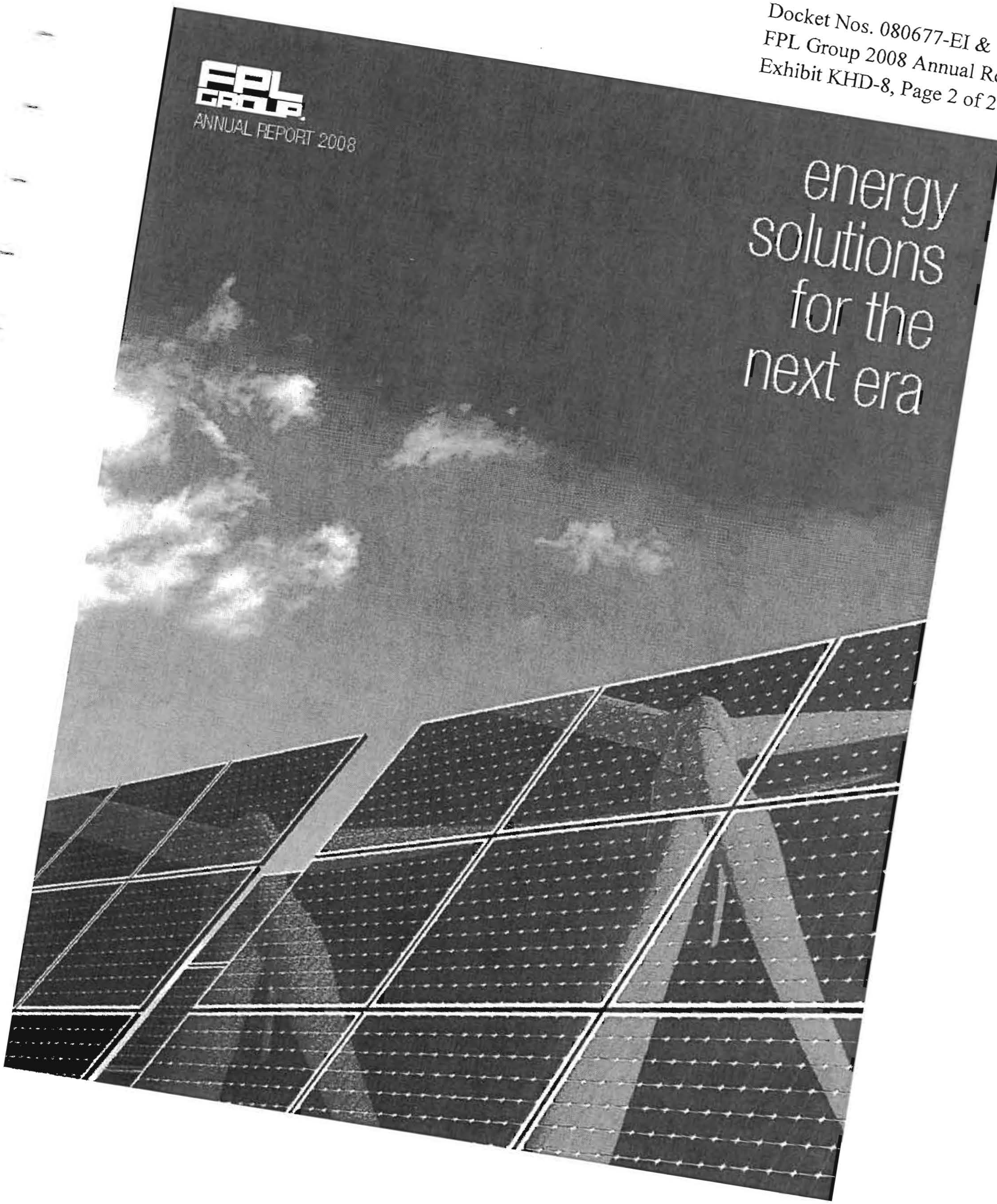
Source: "Annual Results by Segment & Non-GAAP Reconciliations," http://www.investor.fplgroup.com/phoenix.zhtml?c=88486&p=irol-reportsother, July 2008.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 197
COMPANY Office of Public Counsel (OPC) (Direct)Office
WITNESS Kimberly H. Dismukes (KHD-7)
DATE 08/31/09

Florida Power & Light Company
FPL Group 2008 Annual Report

Source: FPL Group 2008 Annual Report.

Docket Nos. 080677-EI & 090130-
FPL Group 2008 Annual Report
Exhibit KHD-8, Page 2 of 2



REDACTED

Florida Power & Light Company
OPC Recommended Affiliate Management Fee Cost Drivers

		2010		
Code	**Description**	**FPL**	**OPC**	**Difference**
c1	MF-Shared	[redacted]		
c2	MF-FPLES & Fibernet			
c3	MF-FPLE & FPL NED			
c3a	MF-FPLE, FPL NED, & Fibernet			
c4	Headcount Incl. Affiliates			
c6	Sq Ft Avg Incl. Subs			
c7	Sq Ft - GO			
c8	Sq Ft - JB			
c9	Average of Shared Benefit Capitalized Software Drivers			
c10	Average of Shared Benefit Capitalized Hardware Drivers			
c11	Affiliate Megawatts - NUC Executive			
c12	Affiliate Megawatts - PGD Executive			
ec1	FTEs of cafeteria bldgs JB, GO, LFO, CSE, PTN, & PSL			
hr2	GO Building Affiliate FTE %			
hr3	JB Building Affiliate FTE %			
hr4	LFO Building Affiliate FTE%			
hr5	Well Program FTE%			
X1	Adjusted number of workstations per business unit for Desktop support (W/S Model #1)			
X2	Actual number of workstations per business unit. (includes Subsidiaries) (W/S Model #2)			
X4	Actual number of mainframe MVS CPU hours by business unit.			
X7	Actual number of workstations per business unit. (includes Subsidiaries), excludes ECCR charges			
XF	Actual number of workstations per business unit. (includes subsidiaries in FPL utility facilities)			
XN1	SAP Volume of Trans by Business Unit (FPLE Support)			
XS1	Based on server ownership information - IM percent allocated out by total workstation count			
XS2	Datacenter alloc. based on server located in GO and JB - IM percent allocated by total workstation count			
XS3	Shared DASD allocation based on server and datacenter models			
Y2	Actual number of workstations per business unit. (includes Subsidiaries) (W/S Model #2)			
Y3	Based on documents processed by BU			
Y7	Actual number of workstations per business unit (Inc subs in FPL facilities) (W/S Model #4)			
YK	Actual % of FPL's subsidiaries workforce as a % of total FPL workforce for subs allocation.			
YN	Actual % of FPL's subsidiaries SAP transactions as a % of total FPL transactions for subs allocation.			
YS1	Based on server ownership information - IM percent allocated out by total workstation count			
YS2	Datacenter alloc. based on server located in GO and JB - IM percent allocated by total workstation count			
YS3	Shared DASD allocation based on server and datacenter models			

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 199
COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Kimberly H. Dismukes (KHD-9)
DATE 08/31/09

Docket Nos. 080677-EI & 090130-EI
OPC Recommended Affiliate Management
Fee Cost Allocation Drivers
Exhibit KHD-9, Page 2 of 2

REDACTED

Florida Power & Light Company
OPC Recommended Affiliate Management Fee Cost Drivers

Code	Description	2011 FPL	2011 OPC	2011 Difference
c1	MF-Shared	[redacted]		
c2	MF-FPLES & Fibernet			
c3	MF-FPLE & FPL NED			
c3a	MF-FPLE, FPL NED, & Fibernet			
c4	Headcount Incl. Affiliates			
c6	Sq Ft Avg Incl. Subs			
c7	Sq Ft - GO			
c8	Sq Ft - JB			
c9	Average of Shared Benefit Capitalized Software Drivers			
c10	Average of Shared Benefit Capitalized Hardware Drivers			
c11	Affiliate Megawatts - NUC Executive			
c12	Affiliate Megawatts - PGD Executive			
ec1	FTEs of cafeteria bldgs JB, GO, LFO, CSE, PTN, & PSL			
hr2	GO Building Affiliate FTE %			
hr3	JB Building Affiliate FTE %			
hr4	LFO Building Affiliate FTE%			
hr5	Well Program FTE%			
X1	Adjusted number of workstations per business unit for Desktop support (W/S Model #1)			
X2	Actual number of workstations per business unit. (includes Subsidiaries) (W/S Model #2)			
X4	Actual number of mainframe MVS CPU hours by business unit			
X7	Actual number of workstations per business unit. (includes Subsidiaries), excludes ECCR charges			
XF	Actual number of workstations per business unit. (includes subsidiaries in FPL utility facilities)			
XN1	SAP Volume of Trans by Business Unit (FPLE Support)			
XS1	Based on server ownership information - IM percent allocated out by total workstation count			
XS2	Datacenter alloc. based on server located in GO and JB - IM percent allocated by total workstation count			
XS3	Shared DASD allocation based on server and datacenter models			
Y2	Actual number of workstations per business unit. (includes Subsidiaries) (W/S Model #2)			
Y3	Based on documents processed by BU			
Y7	Actual number of workstations per business unit (Inc subs in FPL facilities) (W/S Model #4)			
YK	Actual % of FPL's subsidiaries workforce as a % of total FPL workforce for subs allocation.			
YN	Actual % of FPL's subsidiaries SAP transactions as a % of total FPL transactions for subs allocation.			
YS1	Based on server ownership information - IM percent allocated out by total workstation count			
YS2	Datacenter alloc. based on server located in GO and JB - IM percent allocated by total workstation count			
YS3	Shared DASD allocation based on server and datacenter models			

Source: Response to OPC Document Request 106; SFHHA Interrogatory 296; OPC Interrogatory 23; MFR Schedule F-8; FPL Group 2008 Annual Report, p. 11; http://www.fpl.com/environment/plant/west_county_faq.shtml; http://www.fpl.com/environment/solar/desoto.shtml; http://www.fpl.com/environment/solar/martin.shtml; http://www.fpl.com/environment/solar/spacecoast.shtml; http://www.stluciewind.com/questions.shtml.

REDACTED

Florida Power & Light Company
OPC Recommended Massachusetts Formula

FPL	Revenues	Gross PP&E	Total Payroll	Total Shared	FPL / Affiliate
FPL Utility	[redacted]				
FPL NED					
FPL Energy					
Seabrook					
Duane Arnold					
Point Beach					
Fibernet					
FPL ES					
Palms Insur.					
Readi Power					
Total					

OPC					
FPL Utility	[redacted]				
FPL NED					
FPL Energy					
Seabrook					
Duane Arnold					
Point Beach					
Fibernet					
FPL ES					
Palms Insur.					
Readi Power					
Total					

Source: Response to AG Interrogatory 296.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 200
COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Kimberly H. Dismukes (KHD-10)
DATE 08/31/09

REVISED PAGE 1 OF 2

OF EXHIBIT KHD-11

ELIMINATING FPL's CLAIM OF CONFIDENTIALITY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 201
COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Kimberly H. Dismukes (KHD-11)
DATE 08/31/09

Florida Power & Light Company
OPC Recommended Affiliate Management Fee Adjustments
FPL Group Executive Salary Adjustment

Year	FPL Group Executive Salary & Bonus	FPL Allocation Factor	FPL Amount Allocated to Affiliates	OPC Allocation Factor	OPC Amount Allocated to Affiliates	OPC Recommended Adjustment
2010	50,353,703	34%	$ 17,240,876	50%	$ 25,176,852	**$ (7,935,975.87)**
2011	53,128,675	35%	$ 18,658,061	50%	$ 26,564,337	**$ (7,906,276.35)**

REDACTED

Florida Power & Light Company
OPC Recommended Affiliate Management Fee Adjustments
FPL Group Executive Salary Adjustment

Year	FPL Group Executive Salary & Bonus	FPL Allocation Factor	FPL Amount Allocated to Affiliates	OPC Allocation Factor	OPC Amount Allocated to Affiliates	OPC Recommended Adjustment
2010	[redacted]			50%	[redacted]	$ (7,935,975.87)
2011				50%		$ (7,906,276.35)

REDACTED

Florida Power & Light Company
OPC Recommended Affiliate Management Fee Adjustments
Affiliate Allocation Factor Adjustments

Year	FPL Amount Allocated to Affiliates	OPC Amount Allocated to Affiliates	OPC Recommended Adjustment
Costs Allocated Based on the Massachusetts Formula			
2010	[redacted]		$ -
2011			$ (1,393,000.46)
Costs Allocated Based on Specific Drivers			
2010	[redacted]		$ (2,284,350.28)
2011			$ (5,069,195.30)

Source: Response to AG Interrogatory 65; OPC Interrogatory 32; OPC Document Request 234; SFHHA Interrogatory 296.

REDACTED

Florida Power and Light Company
FiberNet Adjustment

Cost Component	Amount
Asset Base for ROI 2010	[redacted]
Fiber	
Shared Fiber	
Electronics	
Shared Electronics	
Capital Spares	
NOC Assets	
Accumulated Depreciation	
Total Allocated Asset Base	
ROI Rate	
FPL Return on Investment	
OPC Recommended ROI	7.41%
OPC Return on Investment	[redacted]
OPC Recommended Adjustment 2010	$ (1,182,224)
OPC Recommended Adjustment 2011	$ (1,182,224)

Source: Response to OPC Interrogatory 8; Exhibit JRW-1.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 202
COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Kimberly H. Dismukes (KHD-12)
DATE 08/31/09

Docket Nos. 080677-EI & 090130-EI
FPLES Margin on Gas Sales
Exhibit KHD-13, Page 1

REDACTED

Florida Power & Light Company
FPLES Margin on Gas Sales Adjustment

Year	Gas Margin
2001	[redacted]
2002	
2003	
2004	
2005	
Total	
Average Annual Gas Margin	
Gain on Sale	
Amortization Period	5
Gain Attributable to Customers	[redacted]
Adjustment to Test Year Revenue 2010	
Adjustment to Test Year Revenue 2011	

Source: Response to OPC Interrogatory 41 and 42.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 203
COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Kimberly H. Dismukes (KHD-13)
DATE 08/31/09

Florida Power & Light Company
Gain on Sale Adjustment

Year	Transaction Sale Price	Transaction Original Cost	Transaction Gain	Transaction Description	Amount of Gain
2007	10. In 2007, FP&L transferred a combustion turbine rotor amounting to $13,735,167 to FPL Group, Inc.	10. The original cost of the assets transferred in 2007 was $9,189,756.	10. The 2007 asset transfers resulted in a gain of $4,545,411, which was recorded above the line.	10. On 6/22/07, a combustion turbine roter was sold to FPL Group, Inc. to restore configuration of combustion turbine.	$4,545,411
2007	11. In 2007, FP&L transferred globe valves amounting to $1,541 to Doswell Limited Partnership.	11. The original cost of the assets transferred in 2007 was $1,149.	11. The 2007 asset transfer resulted in a gain of $392, which was recorded above the line.	11. On 10/10/07, globe valves were sold to Doswell Limited Partnership due to an extended lead time from supplier.	392
2007	12. In 2007, FP&L transferred seal pins, lock wire, and dowel pins amounting to $3,306 to Doswell Limited Partnership.	12. The original cost of the assets transferred in 2007 was $3,198.	12. The 2007 asset transfer resulted in a gain of $108, which was recorded above the line.	12. On 5/14/07, seal pins, lock wire, and dowell pins were sold to Doswell Limited Partnership due to an outage.	108
2007	13. In 2007, FP&L transferred v-seals amounting to $7,617 to Doswell Limited Partnership.	13. The original cost of the assets transferred in 2007 was $6,310.	13. The 2007 asset transfer resulted in a gain of $1,307, which was recorded above the line.	13. In June, v-seals were sold to Doswell Limited Partnership.	1,307
2007	14. In 2007, FP&L transferred gaskets, brackets, ect. amounting to $37,716 to Doswell Limited Partnership.	14. The original cost of the assets transferred in 2007 was $31,411.	14. The 2007 asset transfer resulted in a gain of $6,305, which was recorded above the line.	14. On 6/21/07, gaskets, brackets, ect were sold to Doswell Limited Partnership for their use.	6,305
2007	16. In 2007, FP&L transferred gland, packing, tubing assemblies amounting to $969 to FPL Energy Forney, LLC.	16. The original cost of the assets transferred in 2007 was $746.	16. The 2007 asset transfer resulted in a gain of $223, which was recorded above the line.	16. On 3/6/07, gland, packing, tubing assemblies were sold to FPL Energy Forney, LLC due to an outage.	223
2007	18. In 2007, FP&L transferred probes, axial position amounting to $1,608 to FPL Energy Forney, LLC.	18. The original cost of the assets transferred in 2007 was $1,581.	18. The 2007 asset transfer resulted in a gain of $27, which was recorded above the line.	18. On 4/13/07, probes, axial position were sold to FPL Energy Forney, LLC due to an outage.	27
2007	19. In 2007, FP&L transferred tubing, gaskets, belts, seals, & screws amounting to $5,470 to FPL Energy Forney, LLC.	19. The original cost of the assets transferred in 2007 was $5,408.	19. The 2007 asset transfer resulted in a gain of $62, which was recorded above the line.	19. On 3/29/07, tubing, gaskets, belts, seals, & screws were sold to FPL Energy Forney, LLC due to an outage.	62
2007	20. In 2007, FP&L transferred brackets, retainers, & seals amounting to $13,148 to FPL Energy Forney, LLC.	20. The original cost of the assets transferred in 2007 was $13,032.	20. The 2007 asset transfer resulted in a gain of $116, which was recorded above the line.	20. On 3/5/07, brackets, retainers, & seals were sold to FPL Energy Forney, LLC due to an outage.	116
2007	21. In 2007, FP&L transferred bolts, seals, bearings, screws, tube amounting to $14,788 to FPL Energy Forney, LLC.	21. The original cost of the assets transferred in 2007 was $13,678.	21. The 2007 asset transfer resulted in a gain of $1,110, which was recorded above the line.	21. On 3/21/07, bolts, seals, bearings, screws, tube were sold to FPL Energy Forney, LLC due to an outage.	1,110
2007	22. In 2007, FP&L transferred dresser coupling gaskets amounting to $1,250 to FPLE Calhoun Power Company.	22. The original cost of the assets transferred in 2007 was $1,138.	22. The 2007 asset transfer resulted in a gain of $112, which was recorded above the line.	22. On 3/29/07, dresser coupling gaskets were sold to FPLE Calhoun Power Company due to an outage.	112
2007	24. In 2007, FP&L transferred gaskets amounting to $188 to FPLE Marcus Hook 750, LLC.	24. The original cost of the assets transferred in 2007 was $121.	24. The 2007 asset transfer resulted in a gain of $67, which was recorded above the line.	24. In June, gaskets were sold to FPLE Marcus Hook 750, LLC.	67
2007	31. In 2007, FP&L transferred bellows, gaskets, & bolts amounting to $10,014 to Lamar Power Partners.	31. The original cost of the assets transferred in 2007 was $9,950.	31. The 2007 asset transfer resulted in a gain of $64, which was recorded above the line.	31. On 9/12/07, bellows, gaskets, & bolts were sold to Lamar Power Partner due to an outage.	64

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COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Kimberly H. Dismukes (KHD-14)
DATE 08/31/09

Florida Power & Light Company
Gain on Sale Adjustment

Year	Transaction Sale Price	Transaction Original Cost	Transaction Gain	Transaction Description	Amount of Gain
2007	32. In 2007, FP&L transferred gaskets, bolts, retainers, seals, & tubes amounting to $30,007 to Lamar Power Partners.	32. The original cost of the assets transferred in 2007 was $18,724.	32. The 2007 asset transfer resulted in a gain of $11,283, which was recorded above the line.	32. On 12/3/07, gaskets, bolts, retainers, seals, & tubes were sold to Lamar Power Partner due to an outage.	11,283
2007	33. In 2007, FP&L transferred various parts amounting to $45,282 to Lamar Power Partners.	33. The original cost of the assets transferred in 2007 was $35,811.	33. The 2007 asset transfer resulted in a gain of $9,471, which was recorded above the line.	33. On 4/11/07, various parts were sold to Lamar Power Partner due to Spring outage.	9,471
Total Gain					**$4,576,058**
2008	35. In 2008, FP&L transferred a 225MVA Transformer amounting to $2,900,000 to Calhoun Power Company I, LLC.	35. The original cost of the assets transferred in 2008 was $2,027,026.	35. The 2008 asset transfer resulted in a gain of $872,974, which was recorded above the line.	35. On 7/29/08, a 225MVA Transformer was sold to Calhoun Company I, LLC due to an emergency outage.	$872,974
2008	45. In 2008, FP&L transferred wire & double bolted connectors amounting to $586 to FPL Energy Duane Arnold, LLC.	45. The original cost of the assets transferred in 2008 was $466.	45. The 2008 asset transfer resulted in a gain of $120, which was recorded above the line.	45. On 6/12/08, wire & double bolted connectors were sold to FPL Energy Duane Arnold, LLC due to an outage.	120
2008	46. In 2008, FP&L transferred a relay high pressure amounting to $168 to FPL Energy Duane Arnold, LLC.	46. The original cost of the assets transferred in 2008 was $125.	46. The 2008 asset transfer resulted in a gain of $43, which was recorded above the line.	46. On 9/24/08, a relay high pressure was sold to FPL Energy Duane Arnold, LLC due to an outage.	43
2008	49. In 2008, FP&L transferred an assembly servo for yokogawa amounting to $825 to FPL Energy Point Beach, LLC.	49. The original cost of the assets transferred in 2008 was $530.	49. The 2008 asset transfer resulted in a gain of $295, which was recorded above the line.	49 On 6/26/08, an assembly servo for yokogawa was sold to FPL Energy Point Beach, LLC since it became an obsolete part.	295
2008	53. In 2008, FP&L transferred diaphram actuators amounting to $314 to FPL Energy Point Beach, LLC.	53. The original cost of the assets transferred in 2008 was $261.	53. The 2008 asset transfer resulted in a gain of $53, which was recorded above the line.	53. On 3/31/08, diaphram actuators were sold to FPL Energy Point Beach, LLC due to an outage.	53
2008	57. In 2008, FP&L transferred screws amounting to $2,258 to FPL Energy Point Beach, LLC.	57. The original cost of the assets transferred in 2008 was $737.	57. The 2008 asset transfer resulted in a gain of $1,521, which was recorded above the line.	57. On 4/22/08, screws were sold to FPL Energy Point Beach, LLC due to an outage.	1,521
2008	58. In 2008, FP&L transferred hex nuts amounting to $1,191 to FPL Energy Point Beach, LLC.	58. The original cost of the assets transferred in 2008 was $1,137.	58. The 2008 asset transfer resulted in a gain of $54, which was recorded above the line.	58. On 4/23/08, kit connectors were sold to FPL Energy Point Beach, LLC due to an outage.	54
2008	61. In 2008, FP&L transferred an o-ring amounting to $789 to FPL Energy Point Beach, LLC.	61. The original cost of the assets transferred in 2008 was $182.	61. The 2008 asset transfer resulted in a gain of $607, which was recorded above the line.	61. On 8/28/08, an o-ring was sold to FPL Energy Point Beach, LLC due to an outage.	607
2008	62. In 2008, FP&L transferred lip seals amounting to $334 to FPL Energy Point Beach, LLC.	62. The original cost of the assets transferred in 2008 was $77.	62. The 2008 asset transfer resulted in a gain of $257, which was recorded above the line.	62. On 9/2/08, lip seals were sold to FPL Energy Point Beach, LLC due to an outage.	257
2008	63. In 2008, FP&L transferred a lip seal amounting to $167 to FPL Energy Point Beach, LLC.	63. The original cost of the assets transferred in 2008 was $95.	63. The 2008 asset transfer resulted in a gain of $72, which was recorded above the line.	63. On 9/22/08, a lip seal was sold to FPL Energy Point Beach, LLC due to extended lead time from supplier.	72
2008	64. In 2008, FP&L transferred washers amounting to $1,410 to FPL Energy Point Beach, LLC.	64. The original cost of the assets transferred in 2008 was $837.	64. The 2008 asset transfer resulted in a gain of $573, which was recorded above the line.	64. On 10/15/08, washers were sold to FPL Energy Point Beach, LLC due to an outage.	573

Florida Power & Light Company
Gain on Sale Adjustment

Year	Transaction Sale Price	Transaction Original Cost	Transaction Gain	Transaction Description	Amount of Gain
2008	65. In 2008, FP&L transferred a clamp amounting to $190 to FPL Energy Point Beach, LLC.	65. The original cost of the assets transferred in 2008 was $142.	65. The 2008 asset transfer resulted in a gain of $48, which was recorded above the line.	65. On 10/30/08, a clamp was sold to FPL Energy Point Beach, LLC due to an outage.	48
2008	67. In 2008, FP&L transferred desc bushings amounting to $295 to FPL Energy Seabrook, LLC.	67. The original cost of the assets transferred in 2008 was $217.	67. The 2008 asset transfer resulted in a gain of $78, which was recorded above the line.	67. On 4/17/08, desc bushings were sold to FPL Energy Seabrook, LLC due to an outage.	78
2008	70. In 2008, FP&L transferred a pump 460T amounting to $9.448 to FPL Energy Wyman, LLC.	70. The original cost of the assets transferred in 2008 was $8,437.	70. The 2008 asset transfer resulted in a gain of $1,011, which was recorded above the line.	70. On 10/16/08, a pump 460T was sold to FPL Energy Wyman, LLC due to pump failure.	1,011
Total Gain					**$877,706**
2007 and 2008 Gain on Sale					**$5,453,764**
Amortization Period					**5**
Annual Amortization of Gain on Sale 2010					**$ 1,090,753**
Annual Amortization of Gain on Sale 2011					**$ 1,090,753**

Source: Response to OPC Interrogatory 41.

Florida Power & Light Company
Power Monitoring Revenue Adjustment

	2010	2011
Power Monitoring Revenue Included in Test Year	$ 654,000	$ 667,000
Power Monitoring Revenue - Response to OPC Interrogatory 59	890,336	934,885
Adjustment: Increase Test Year Revenue Account 451 Msc Revenue	$ 236,336	$ 267,885

Source: Response to OPC Interrogatory 59.

FLORIDA PUBLIC SERVICE COMMISSION
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COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Kimberly H. Dismukes (KHD-15)
DATE 08/31/09

REDACTED

Florida Power and Light Company
Summary of Affiliate Adjustments

	2010	2011
FPL Group Executive Adjustment	$ (7,935,976)	$ (7,906,276)
Affiliate Management Fee Cost Driver Adjustment	$ (2,284,350)	$ (5,069,195)
Affiliate Management Fee Massachusetts Formula Adjustment	$ -	$ (1,393,000)
FiberNet Rate of Return Adjustment	$ (1,182,224)	$ (1,182,224)
FPLES Margin on Gas Sales Adjustment - Confidential	[redacted]	[redacted]
Historical Museum Adjustment	$ 45,470	$ 46,764
Gain on Sale of Affiliate Transfers Adjustment	$ 1,090,753	$ 1,090,753
Monitoring Revenue Adjustment	$ 236,336	$ 267,885

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 206
COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Kimberly H. Dismukes (KHD-16)
DATE 08/31/09

Appendix A
Educational Background, Research, and Related Business Experience
J. Randall Woolridge

J. Randall Woolridge is a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed Faculty Fellow in Business Administration in the College of Business Administration of the Pennsylvania State University in University Park, PA. In addition, Professor Woolridge is Director of the Smeal College Trading Room and President and CEO of the Nittany Lion Fund, LLC.

Professor Woolridge received a Bachelor of Arts degree in Economics from the University of North Carolina, a Master of Business Administration degree from the Pennsylvania State University, and a Doctor of Philosophy degree in Business Administration (major area-finance, minor area-statistics) from the University of Iowa. At Iowa he received a Graduate Fellowship and was awarded membership in Beta Gamma Sigma, a national business honorary society. He has taught Finance courses at the University of Iowa, Cornell College, and the University of Pittsburgh, as well as the Pennsylvania State University. These courses include corporation finance, commercial and investment banking, and investments at the undergraduate, graduate, and executive MBA levels.

Professor Woolridge's research has centered on the theoretical and empirical foundations of corporation finance and financial markets and institutions. He has published over 35 articles in the best academic and professional journals in the field, including the *Journal of Finance*, the *Journal of Financial Economics*, and the *Harvard Business Review*. His research has been cited extensively in the business press. His work has been featured in the *New York Times*, *Forbes*, *Fortune*, *The Economist*, *Financial World*, *Barron's*, *Wall Street Journal*, *Business Week*, *Washington Post*, *Investors' Business Daily*, *Worth Magazine*, *USA Today*, and other publications. In addition, Dr. Woolridge has appeared as a guest to discuss the implications of his research on CNN's *Money Line*, CNBC's *Morning Call* and *Business Today*, and Bloomberg Televisions' *Morning Call*.

Professor Woolridge's popular stock valuation book, *The StreetSmart Guide to Valuing a Stock* (McGraw-Hill, 2003), was released in its second edition. He has also co-authored *Spinoffs and Equity Carve-Outs: Achieving Faster Growth and Better Performance* (Financial Executives Research Foundation, 1999) as well as a textbook entitled *Applied Principles of Finance* (Kendall Hunt, 2006). Dr. Woolridge is a founder and a managing director of www.valuepro.net - a stock valuation website.

Professor Woolridge has also consulted with and prepared research reports for major corporations, financial institutions, and investment banking firms, and government agencies. In addition, he has directed and participated in over 500 university- and company- sponsored professional development programs for executives in 25 countries in North and South America, Europe, Asia, and Africa.

Dr. Woolridge has prepared testimony and/or provided consultation services in the following cases:

Pennsylvania: Dr. Woolridge has prepared testimony on behalf of the Pennsylvania Office of Consumer Advocate in the following cases before the Pennsylvania Public Utility Commission; Bell Telephone Company (R-811819), Peoples Natural Gas Company (R-832315), Pennsylvania Power Company (R-832409), Western Pennsylvania Water Company (R-832381), Pennsylvania Power Company (R-842740), Pennsylvania Gas and Water Company (R-850178), Metropolitan Edison Company (R-860384), Pennsylvania Electric Company (R-860413), North Penn Gas Company (R-860535), Philadelphia Electric Company (R-870629), Western Pennsylvania Water Company (R-870825), York Water Company (R-870749), Pennsylvania-American Water Company (R-880916), Equitable Gas Company (R-880971), the Bloomsburg Water Co. (R-891494), Columbia Gas of Pennsylvania, Inc. (R-891468), Pennsylvania-American Water Company (R-90562), Breezewood Telephone Company (R-901666), York Water Company (R-901813), Columbia Gas of Pennsylvania, Inc. (R-901873), National Fuel Gas Corporation (R-911912), Pennsylvania-American Water Company (R-911909), Borough of Media Water Fund (R-912150), UGI Utilities, Inc. - Electric Utility Division (R-922195), Dauphin Consolidated Water Supply Company - General Waterworks of

FLORIDA PUBLIC SERVICE COMMISSION			
DOCKET NO.	080677-EI & 090130-EI	**EXHIBIT**	207
COMPANY	Office of Public Counsel (OPC) (Direct)		
WITNESS	Woolridge - Appendix A		
DATE	09/03/09		

Appendix A
Educational Background, Research, and Related Business Experience
J. Randall Woolridge

Pennsylvania, Inc, (R-932604), National Fuel Gas Corporation (R-932548), Commonwealth Telephone Company (I-920020), Conestoga Telephone and Telegraph Company (I-920015), Peoples Natural Gas Company (R-932866), Blue Mountain Consolidated Water Company (R-932873), National Fuel Gas Corporation (R-942991), UGI - Gas Division (R-953297), UGI - Electric Division (R-953534), Pennsylvania-American Water Company (R-973944), Pennsylvania-American Water Company (R-994638), Philadelphia Suburban Water Company (R-994868;R-994877;R-994878; R-9948790), Philadelphia Suburban Water Company (R-994868), Wellsboro Electric Company (R-00016356), Philadelphia Suburban Water Company (R-00016750), National Fuel Gas Corporation (R-00038168), Pennsylvania-American Water Company (R-00038304), York Water Company (R-00049165), Valley Energy Company (R-00049345), Wellsboro Electric Company (R-00049313), National Fuel Gas Corporation (R-00049656), T.W. Phillips Gas and Oil Co. (R-00051178), PG Energy (R-00061365), City of Dubois Water Company (Docket No. R-00050671), R-00049165), York Water Company (R-00061322), Emporium Water Company (R-00061297), Pennsylvania-American Water Company (R-00072229),

New Jersey: Dr. Woolridge prepared testimony for the New Jersey Department of the Public Advocate, Division of Rate Counsel: New Jersey-American Water Company (R-91081399J), New Jersey-American Water Company (R-92090908J), and Environmental Disposal Corp. (R-94070319).

Alaska: Dr. Woolridge prepared testimony for Attorney General's Office of Alaska: Golden Heart Utilities, Inc. and College Utilities Corp. (Water Public Utility Service TA-29-118 and Sewer Public Utility Service TA-82-97), Anchorage Water and Wastewater Utility (TA-106-122).

Arizona: Dr. Woolridge prepared testimony for Utility Division staff of the Arizona Corporation Commission, Arizona Public Service Company (Docket No. E-01345A-06-0009).

Hawaii: Dr. Woolridge prepared testimony for the Hawaii Office of the Consumer Advocate: East Honolulu Community Services, Inc. (Docket No. 7718).

Delaware: Dr. Woolridge prepared testimony for the Delaware Division of Public Advocate: Artesian Water Company (R-00-649). Dr. Woolridge prepared testimony for the staff of the Public Service Commission: Artesian Water Company (R-06-158).

Ohio: Dr. Woolridge prepared testimony for the Ohio Office of Consumers' Council: SBC Ohio (Case No. 02-1280-TP-UNC R-00-649), Cincinnati Gas & Electric Company (Case No. 05-0059-EL-AIR), Dominion East Ohio Company (Case No. 07-829-GA-AIR), Cleveland Electric Illuminating Company and Toledo Edison Company (Case No. 08-935-EL-SSO), Columbia Gas of Ohio, Inc. (Case No. 08-0072-GA-AIR), and Columbus Southern Power Company (Case No. 08-917-EL-SSO).

Texas: Dr. Woolridge prepared testimony for the Atmos Cities Steering Committee: Mid-Texas Division of Atmos Energy Corp. (Docket No. 9670).

New York: Dr. Woolridge prepared testimony for the County of Nassau in New York State: Long Island Lighting Company (PSC Case No. 942354).

Florida: Dr. Woolridge prepared testimony for the Office of Public Counsel in Florida: Florida Power & Light Co. (Docket No. 050045-EL), Tampa Electric Company (Docket No 080317-EI), Peoples Gas Company (Docket No 080318-GU).

Appendix A
Educational Background, Research, and Related Business Experience
J. Randall Woolridge

Indiana: Dr. Woolridge prepared testimony for the Indiana Office of Utility Consumer Counsel (OUCC) in the following cases: Southern Indiana Gas and Electric Company (IURC Cause No. 43111 and IURC Cause No. 43112).

Oklahoma: Dr. Woolridge prepared testimony for the Oklahoma Industrial Energy Companies (OIEC) in the following cases: Public Service Company of Oklahoma (Cause No. PUD 200600285), Oklahoma Gas & Electric Company (Cause No. PUD 200700012).

Connecticut: Dr. Woolridge prepared testimony for the Office of Consumer Counsel in Connecticut: United Illuminating (Docket No. 96-03-29), Yankee Gas Company (Docket No. 04-06-01), Southern Connecticut Gas Company (Docket No. 03-03-17), the United Illuminating Company (Docket No. 05-06-04), Connecticut Light and Power Company (Docket No. 05-07-18), Birmingham Utilities, Inc. (Docket No. 06-05-10), Connecticut Water Company (Docket No. 06-07-08), Connecticut Natural Gas Corp. (Docket No. 06-03-04), Aquarion Water Company (Docket No. 07-05-09), Yankee Gas Company (Docket No. 06-12-02), Connecticut Light and Power Company (Docket No. 07-07-01), and the United Illuminating Company (Docket No. 08-07-03).

California: Dr. Woolridge prepared testimony for the Office of Ratepayer Advocate in California: San Gabriel Valley Water Company (Docket No. 05-08-021), Pacific Gas & Electric (Docket No. 07-05-008), San Diego Gas & Electric (Docket No. 07-05-007), Southern California Edison (Docket No. 07-05-003), California-American Water Company (Docket No. 08-05-003), Golden State Water Company (Docket No. 08-05-004), and California Water Service Company (Docket No. 08-05-002).

South Carolina: Dr. Woolridge prepared testimony for the Office of Regulatory Staff in South Carolina: South Carolina Electric and Gas Company (Docket No. 2005-113-G), Carolina Water Service Co. (Docket No. 2006-87-WS), Tega Cay Water Company (Docket No. 2006-97-WS), United Utilities Companies, Inc. (Docket No. 2006-107-WS).

Missouri: Dr. Woolridge prepared testimony for the Department of Energy in Missouri: Kansas City Power & Light Company (CASE NO. ER-2006-0314). Dr. Woolridge prepared testimony for the Office of Attorney General of Missouri: Union Electric Company (CASE NO. ER-2007-0002).

Kentucky: Dr. Woolridge prepared testimony for the Office of Attorney General in Kentucky: Kentucky-American Water Company (Case No. 2004-00103), Union Heat, Light, and Power Company (Case No. 2004-00042), Kentucky Power Company (Case No. 2005-00341), Union Heat, Light, and Power Company (Case No. 2006-00172), Atmos Energy Corp. (Case No. 2006-00464), Columbia Gas Company (Case No. 2007-00008), Delta Natural Gas Company (Case No. 2007-00089), Kentucky-American Water Company (Case No. 2007-00143).

Washington, D.C.: Dr. Woolridge prepared testimony for the Office of the People's Counsel in the District of Columbia: Potomac Electric Power Company (Formal Case No. 939).

Washington: Dr. Woolridge consulted with trial staff of the Washington Utilities and Transportation Commission on the following cases: Puget Energy Corp. (Docket Nos. UE-011570 and UG-011571); and Avista Corporation (Docket No. UE-011514).

Kansas: Dr. Woolridge prepared testimony on behalf of the Kansas Citizens' Utility Ratepayer Board in the following cases: Western Resources Inc. (Docket No. 01-WSRE-949-GIE), UtiliCorp (Docket No. 02-UTCG701-CIG), and Westar Energy, Inc. (Docket No. 05-WSEE-981-RTS).

Appendix A
Educational Background, Research, and Related Business Experience
J. Randall Woolridge

Utah: Dr. Woolridge prepared testimony on behalf of the Utah Committee on Consumer Services (CCS) in the following case: Questar Gas Company (Docket No. No. 07-057-13).

FERC: Dr. Woolridge has prepared testimony on behalf of the Pennsylvania Office of Consumer Advocate in the following cases before the Federal Energy Regulatory Commission: National Fuel Gas Supply Corporation (RP-92-73-000) and Columbia Gulf Transmission Company (RP97-52-000).
Vermont: Dr. Woolridge prepared testimony for the Department of Public Service in the Central Vermont Public Service (Docket No. 6988) and Vermont Gas Systems, Inc. (Docket No. 7160).

Exhibit JRW-1

Florida Power & Light Company
Cost of Capital

Weighted Average Cost of Capital - Regulatory Capital Structure

Capital Source	Capitalization Ratio	Cost Rate	Weighted Cost Rate
Short Term Debt	3.03%	2.27%	0.07%
Long-Term Debt	33.67%	5.14%	1.73%
Customer Deposits	3.02%	5.98%	0.18%
Common Equity	43.84%	9.50%	4.16%
Investment Tax Credits	0.31%	7.41%	0.02%
Deferred Income Taxes	16.14%	0.00%	0.00%
Total Capital	100.00%		6.17%

Weighted Average Cost of Capital - Conventional Capital Structure

Capital Source	Capitalization Ratio	Cost Rate	Weighted Cost Rate
Short Term Debt	3.76%	2.27%	0.09%
Long-Term Debt	41.80%	5.14%	2.15%
Common Equity	54.43%	9.50%	5.17%
Total	100.00%		7.41%

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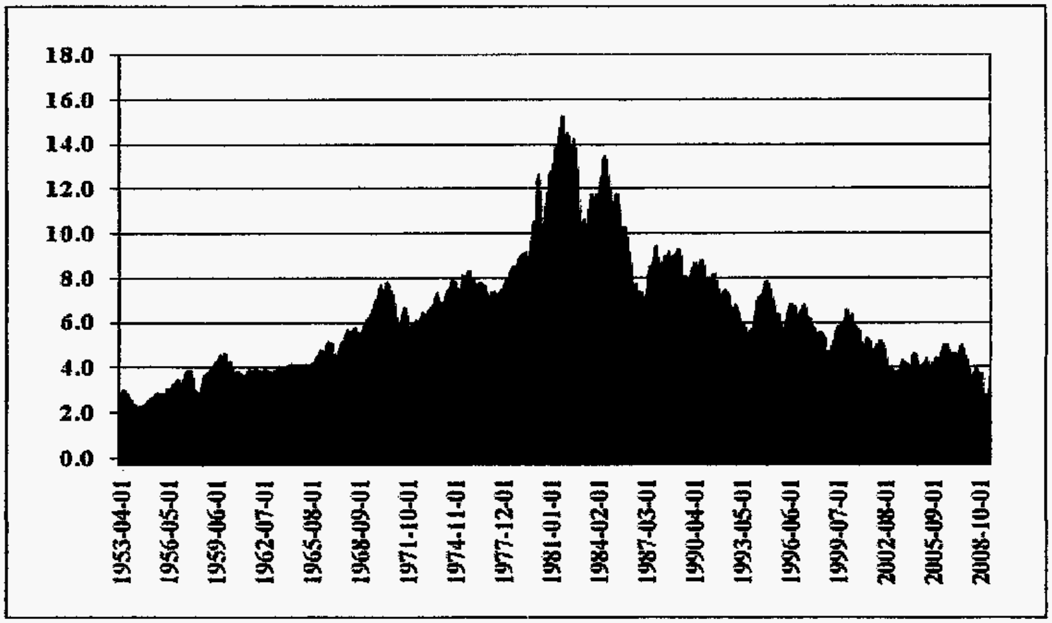
Exhibit JRW-2

Panel A
Ten-Year Treasury Yields
1953-Present



Source: http://research.stlouisfed.org/fred2/data/GS10.txt

Panel B
Long-Term Moody's Baa Yields Minus Ten-Year Treasury Yields
2000-Present

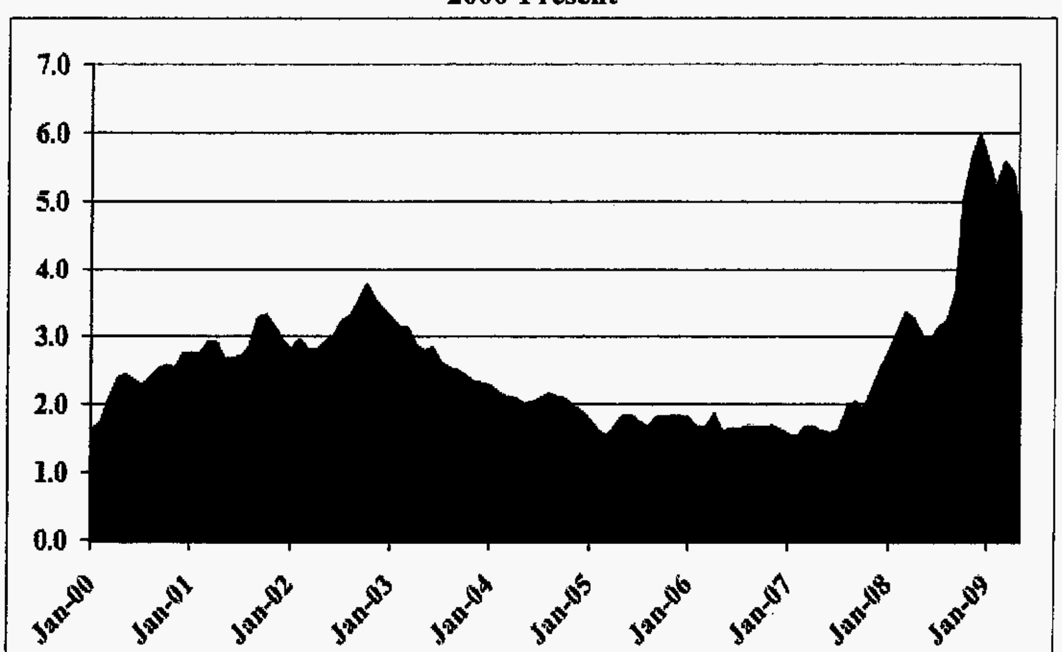


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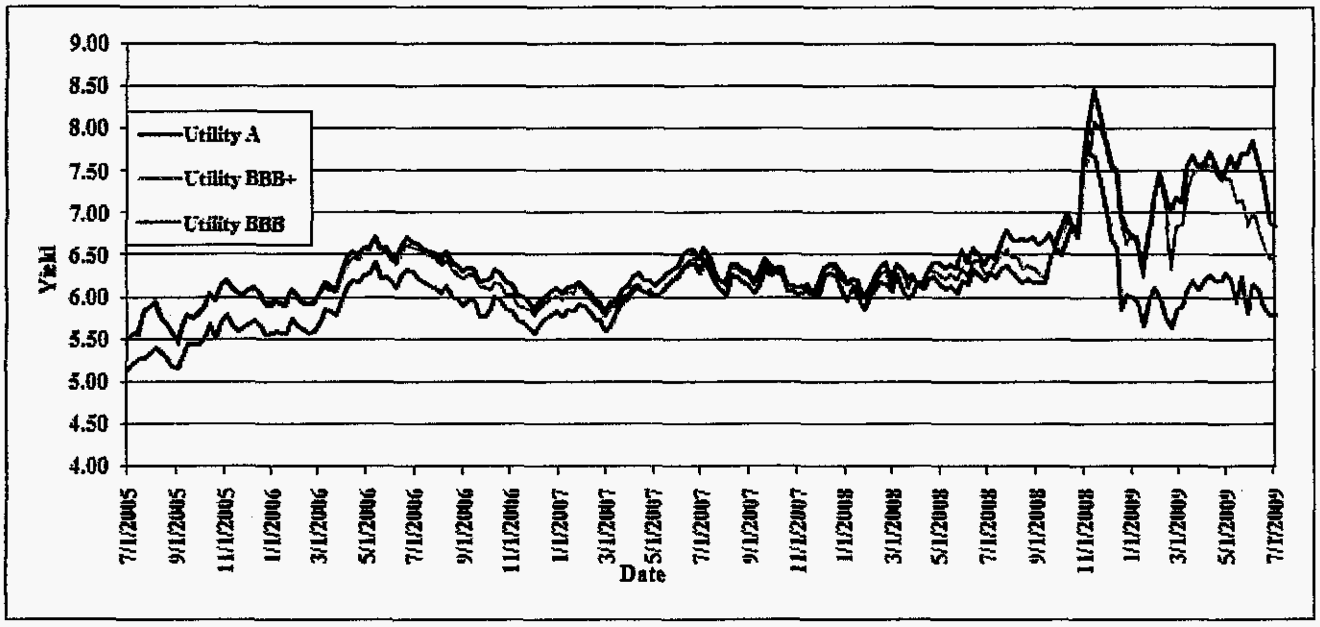
Exhibit JRW-3
Panel A
Thirty-Year Public Utility Yields



Panel B
Thirty-Year Public Utility Yield Spread Over Treasuries

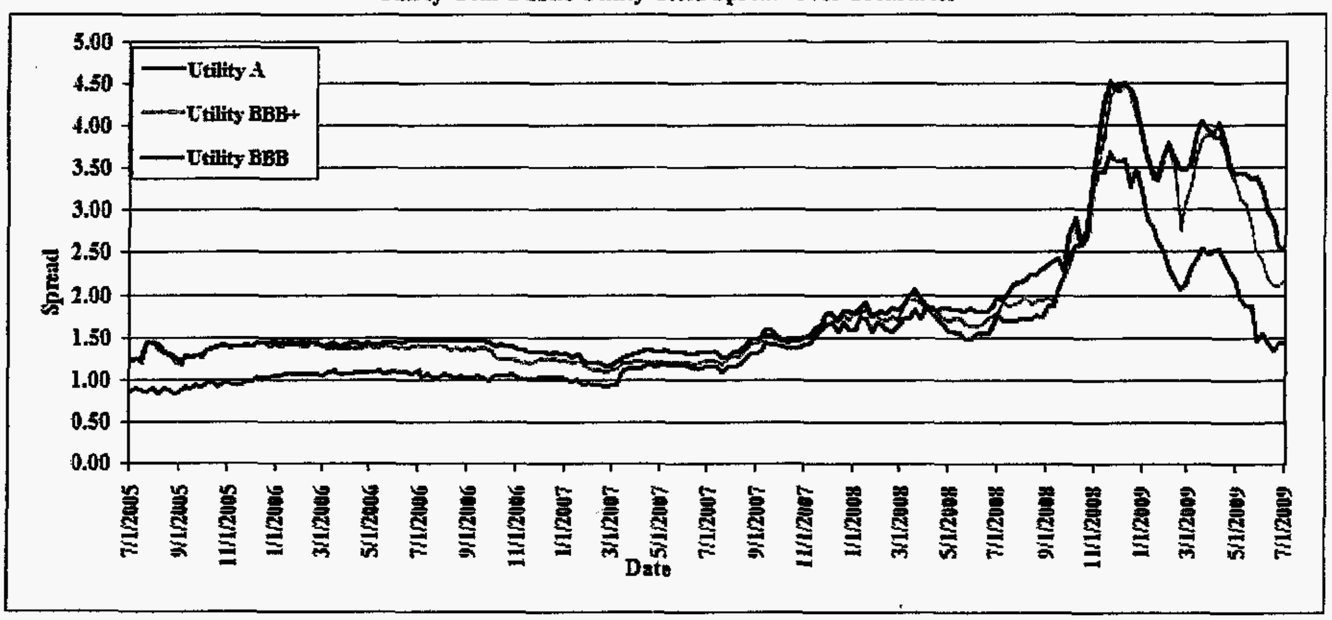


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Exhibit JRW-3
Bonds a Bright Spot for Utilities in '08

THE WALL STREET JOURNAL.

JANUARY 13, 2009

Bonds a Bright Spot for Utilities in '08

Debt Issuance Rose 34% as Investors Shunned Commercial Paper, Stocks

By REBECCA SMITH

Even as credit markets seized last year, the utility industry achieved a noteworthy feat: It sold more bonds than it had in years.

Utilities with investment-grade credit ratings sold $47 billion of corporate bonds last year, 34% more than the $35 billion issued in 2007 and 77% more than the $26.5 billion of 2006.

The 2008 increase marked one of the few bright spots in the overall bond market, which registered a decline in issuance of nearly 35%, to $645 billion from $987 billion in 2007, according to Thomson SDC.

Pacificorp's Huntington Power Plant in Huntington, Utah

Some of Heftiest Utility Bond Sales

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	Oncor Electric Delivery	[illegible]	[illegible]	[illegible]
[illegible]	Florida Power	[illegible]	[illegible]	[illegible]
[illegible]	Consolidated Edison of N.Y.	[illegible]	[illegible]	[illegible]
[illegible]	Pacificorp	[illegible]	[illegible]	[illegible]
[illegible]	Duke Energy Carolinas	[illegible]	[illegible]	[illegible]
[illegible]	Sempra Energy	[illegible]	[illegible]	[illegible]
[illegible]	Virginia Electric & Power	[illegible]	[illegible]	[illegible]
[illegible]	NiSource Finance	[illegible]	[illegible]	[illegible]
[illegible]	Commonwealth Edison	[illegible]	[illegible]	[illegible]
[illegible]	MidAmerican Energy	[illegible]	[illegible]	[illegible]

Utilities are the third-largest debt issuers after government and finance, requiring a steady supply of cash to build power plants, pipelines and transmission lines and to meet tightening environmental requirements. When credit markets tanked last autumn, many utilities were hurt as market valuations tumbled amid investor fears that demand for their services would decline and that they would have difficulty raising the large sums of money they require, at least at affordable rates.

The full-year issuance for utilities is encouraging, analysts said, because it shows a vital sector of the economy has adapted to changing conditions and is getting the money it needs to support basic operations as well as fund expansion.

Utilities will be critical players in President-elect Barack Obama's economic-stimulus plan, particularly in efforts to modernize the nation's electric grid and to triple the amount of energy garnered from renewable sources in coming years.

Exhibit JRW-3
Bonds a Bright Spot for Utilities in '08

Key to that effort is the ability of utilities to finance big infrastructure projects. Steve Tulip, a managing director in debt capital markets for Goldman Sachs Group, says utilities stood out in a stormy credit landscape. "The flight to quality clearly has benefited the power sector," Mr. Tulip said. "Investors are looking for safe havens."

Utilities leaned on the bond market last year partly out of desperation because commercial paper markets came unglued and they were unable, in some cases, to refinance short-term notes. Meantime, sagging stock market valuations made equity issuance unattractive. Bonds offered a better way for companies to secure stable money and garner some measure of protection against what could be a rough 2009.

"We expect a choppy economy," said Bill Johnson, chief executive of Progress Energy Inc., a utility that operates in the Carolinas and Florida that sold $600 million of bonds Jan. 8. It hopes that will be sufficient to tide it over until 2010. "It felt good to get that one off the table," he said.

The 10-year bonds carried a coupon rate of 5.3%, substantially less than the 7.5% to 8% rate executives felt they might have to swallow, based on prevailing rates in mid- to late-December.

"People have turned the page on 2008 and spreads have come down for people like us," said Mark Mulhern, Progress Energy's chief financial officer.

Pepco Holdings Inc. did three $250-million bond issuances in November and December for its three utilities, including sales of five-year, 10-year and 30-year bonds. Though the spreads to comparable U.S. Treasurys were high -- such as the 4.12 percentage point spread for 10-year bonds issued by Atlantic City Electric -- the actual coupon rates "weren't bad," said Chief Financial Officer Paul Barry. Interest rates were 7.75% for the Atlantic City Electric issuance and 6.4% and 6.5% on two other issues.

Higher financing costs for utilities could put pressure on customer rates if they continue long enough. That is because financing costs typically are a pass-through expense, though there sometimes is a lag between when costs are incurred and when they get folded into rates. That lag can be a drag on utility earnings.

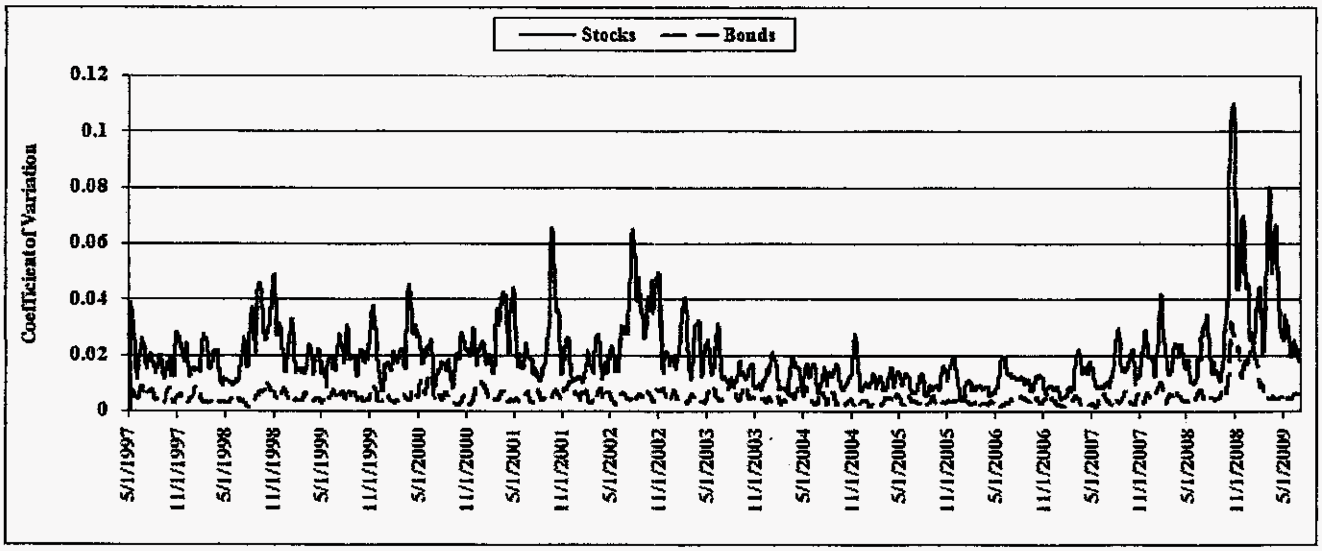
The financing cost, expressed as a "spread," or an amount above the interest rates for U.S. Treasury notes of similar duration, widened to about five to eight percentage points by the end of 2008 from two or three percentage points at the beginning of the year. The actual interest rates paid to bond purchasers, called the coupon rates, didn't rise to unbearable levels because Treasury interest rates fell.

In the fourth quarter, issuance by investment-grade utilities topped $10 billion. In 2008, utilities widened their share of total U.S. investment-grade bond issuance to 7% from 4% in 2007 and 3% in 2006.

Total bond issuance by financial firms, such as commercial banks and investment banks, skidded 52% to $322 billion from $676 billion in 2007 and $686 billion in 2006. For nonfinancial firms, with utilities excluded, total issuance held steady at $275 billion for 2008 and 2007, up from $217 billion in 2006.

Exhibit JRW-3

Panel C
Coefficient of Variation
S&P 500 Price CV and Bear Sterns Bond Price Index CV



Panel D
Coefficient of Variation
S&P 500 Price CV/Bear Sterns Bond Price Index CV

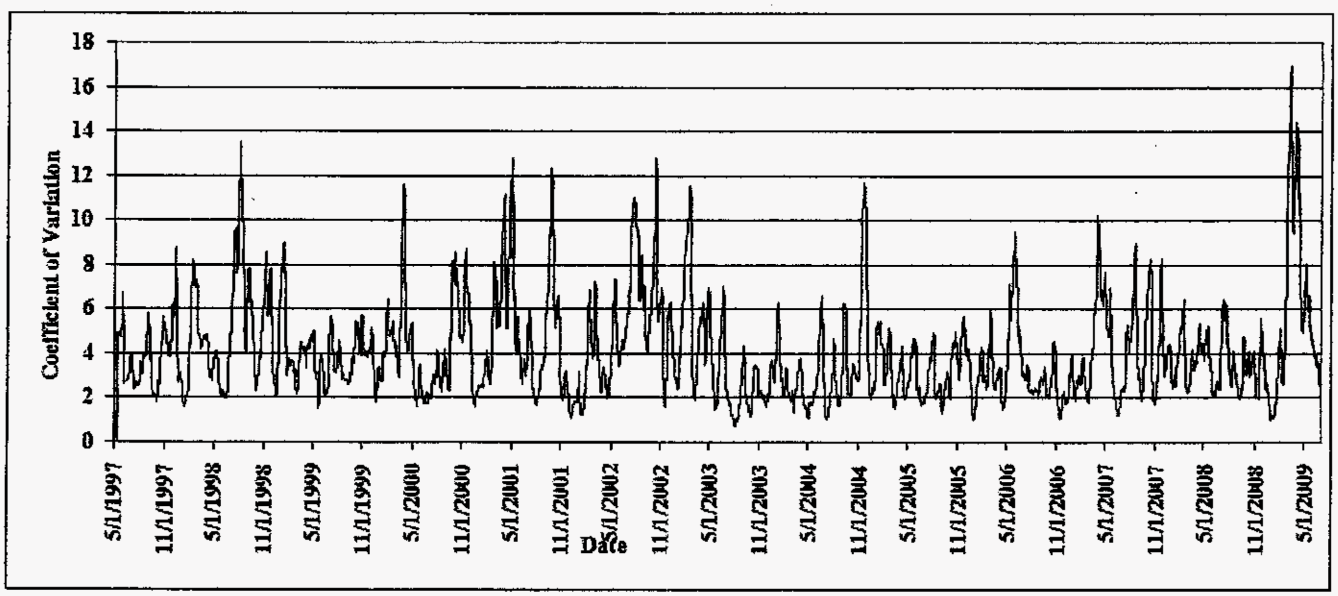


Exhibit JRW-4
Florida Power & Light Company
Summary Financial Statistics for Electric Proxy Group

Electric Proxy Group

	Company	Operating Revenue ($mil)	Percent Elec Revenue	Net Plant ($mil)	S&P Bond Rating	Moody's Bond Rating	Pre-Tax Interest Coverage	Primary Service Area	Common Equity Ratio	Return on Equity	Market to Book Ratio
1	American Electric Power Co. (NYSE-AEP)	14,431.0	94	33,251.0	BBB	Baa1	3.0	11 States	37	11.4	0.93
2	Edison International (NYSE-EIX)	13,841.0	80	19,321.0	A	A2	3.9	CA	44	14.3	0.95
3	Entergy Corporation (NYSE-ETR)	13,018.1	77	22,619.7	A-	Baa2	4.3	AK,LA,MS,TX	41	14.7	1.68
4	FirstEnergy Corporation (NYSE-FE)	13,684.0	89	18,207.0	BBB	Baa2	4.0	OH,PA,NJ	36	14.6	1.35
5	FPL Group, Inc. (NYSE-FPL)	16,680.0	70	33,053.0	A	A1	3.6	FL	41	13.4	1.84
6	Northeast Utilities (NYSE-NU)	5,873.6	81	8,313.5	BBB+	Baa1	2.3	CT,NH,MA	41	7.6	0.97
7	PG&E Corporation (NYSE-PCG)	14,326.0	74	26,923.0	BBB+	A3	3.1	CA	47	11.8	1.36
8	Progress Energy Inc. (NYSE-PGN)	9,535.0	98	18,636.0	A-	A2	3.1	NC,SC,FL	45	9.7	1.13
9	Southern Company (NYSE-SO)	17,110.0	99	36,767.7	A	A2	4.1	GA,AL,FL,MS	39	14.4	1.66
10	Xcel Energy Inc. (NYSE-XEL)	10,870.3	79	17,947.5	A-	A3	2.9	CO,MN,WI,ND,SD,MI	45	9.8	1.11
	Mean	12,936.9	84	23,503.9	A-	A3	3.4		42	12.2	1.30

Data Source: AUS *Utility Reports*, June 2009; Service Area, and Pre-Tax Interest Coverage is from *Value Line Investment Survey*.

Company	Operating Revenue ($mil)	Percent Elec Revenue	Net Plant ($mil)	S&P Bond Rating	Moody's Bond Rating	Pre-Tax Interest Coverage	Primary Service Area	Common Equity Ratio	Return on Equity	Market to Book Ratio
Florida Power & Light	11,649.0	100	18,783.0	A	A1	4.6	FL	57	10.3	

Data Source: 2008 FP&L Financial Statements

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Exhibit JRW-5
Florida Power & Light Company
Capital Structure Ratios

Panel A - FP&L's Recommended Capitalization Ratios - Investor Provided Capital - With Imputed Debt

Capital	Capitalization Ratios	Capitalization Ratios
Short Term Debt	161,857	1.10%
Long-Term Debt	6,327,047	43.14%
Common Equity	8,178,980	55.76%
Total Capital*	14,667,884	100.00%

* Includes $950M adjustment for PPAs
Source: Testimony of Mr. Pimentel

Panel B - FP&L's Recommended Capitalization Ratios - Investor Provided Capital - Without Imputed Debt

Capital	Capitalization Ratios	Capitalization Ratios
Short Term Debt	161,857	1.18%
Long-Term Debt	5,377,787	39.20%
Common Equity	8,178,980	59.62%
Total Capital*	13,718,624	100.00%

* Excludes $950M adjustment for PPAs
Source: Testimony of Mr. Pimentel

Panel C -FP&L's Year-End Capital Structure Per Books - 2004-2008

Capital	2004	2005	2006	2007	2008	Average
Short Term Debt	10.74%	11.59%	5.09%	8.27%	7.31%	8.60%
Long-Term Debt	24.22%	28.08%	34.03%	36.16%	35.62%	31.62%
Common Equity	65.04%	60.33%	60.88%	55.56%	57.07%	59.78%
Total Capital	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Panel D -FPL Group's Year-End Capital Structure Per Books - 2004-2008

Capital	2004	2005	2006	2007	2008	Average
Short Term Debt	9.94%	13.42%	12.32%	9.90%	11.31%	11.37%
Long-Term Debt	46.45%	42.09%	43.08%	46.17%	48.09%	45.17%
Common Equity	43.61%	44.50%	44.60%	43.94%	40.61%	43.45%
Total Capital	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Panel E - Average Capital Structure Ratios of Electric Proxy Group (Including Short-Term Debt)

Capital	3/31/09	12/31/08	9/30/08	6/30/08	Average
Short Term Debt	7.82%	8.91%	8.86%	8.40%	8.50%
Long-Term Debt	51.30%	50.63%	50.47%	49.95%	50.59%
Preferred Stock	0.85%	0.85%	0.86%	0.97%	0.88%
Common Equity	40.03%	39.61%	39.82%	40.68%	40.03%
Total Capital	100.00%	100.00%	100.00%	100.00%	100.00%

Source: Page 3 of Exhibit JRW-5

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Exhibit JRW-5
Florida Power & Light Company
Capital Structure Ratios

Panel F - FP&L's Year-End Capitalization - Per Books - 2009 - 2010

Capital	2009	2010	Average
Short Term Debt	710,087	549,207	629,647
Long-Term Debt	6,312,418	7,670,689	6,991,554
Common Equity	8,648,116	9,559,882	9,103,999
Total Capital	15,670,621	17,779,778	16,725,200
Capital	2009	2010	Average
Short Term Debt	4.53%	3.09%	3.76%
Long-Term Debt	40.28%	43.14%	41.80%
Common Equity	55.19%	53.77%	54.43%
Total Capital	100.00%	100.00%	100.00%

Source: MFR D-2 Work Papers

Panel G - OPC Recommended Capital Structure for FP&L

Capital	Capitalization Amounts	Capitalization Ratios
Short Term Debt	629,647	3.03%
Long-Term Debt	6,991,554	33.67%
Customer Deposits	626,383	3.02%
Common Equity	9,103,999	43.84%
Investment Tax Credits	63,939	0.31%
Deferred Income Taxes	3,351,931	16.14%
Total Capital	20,767,453	100.0%

Source: Schedule D-1A, MFR D-2 Work Papers, all numbers, per books

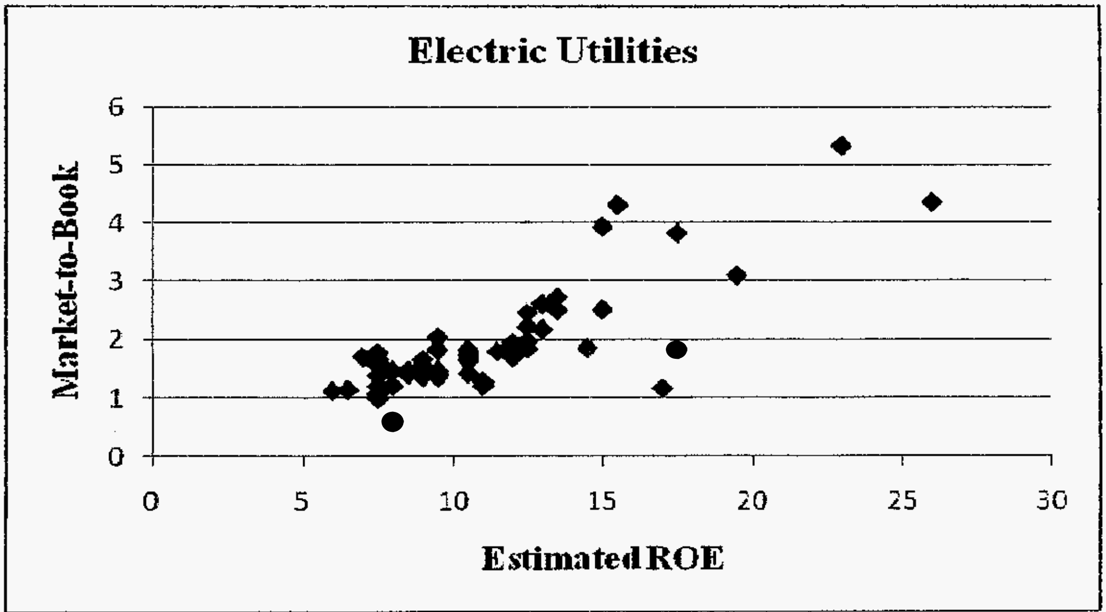
Capital Structure Investor Sources Only:	
Long Term Debt	3.76%
Short Term Debt	41.80%
Common Equity	54.43%
Total	100.00%

Exhibit JRW-5
Florida Power & Light Company
Capital Structure Ratios with Short-Term Debt
Electric Proxy Group

AEP		3/31/09	12/31/08	9/30/08	6/30/08	AEP		3/31/09	12/31/08	9/30/08	6/30/08
	Short Term Debt	3,094,000	2,423,000	1,984,000	2,265,000		Short Term Debt	10.27%	8.46%	7.03%	7.97%
	Long-Term Debt	16,078,000	15,536,000	15,325,000	15,532,000		Long-Term Debt	53.39%	54.22%	54.29%	54.64%
	Preferred Stock						Preferred Stock	0.00%	0.00%	0.00%	0.00%
	Common Equity	10,940,000	10,693,000	10,917,000	10,631,000		Common Equity	36.33%	37.32%	38.68%	37.40%
	Total	30,112,000	28,652,000	28,226,000	28,428,000		Total	100.00%	100.00%	100.00%	100.00%
EIX						EIX					
	Short Term Debt	2,002,000	2,501,000	2,163,000	1,296,000		Short Term Debt	8.12%	9.73%	9.02%	6.14%
	Long-Term Debt	11,975,000	11,863,000	10,710,000	9,535,000		Long-Term Debt	48.58%	46.17%	44.68%	45.16%
	Preferred Stock	907,000	907,000	907,000	907,000		Preferred Stock	3.68%	3.53%	3.78%	4.30%
	Common Equity	9,768,000	10,424,000	10,188,000	9,374,000		Common Equity	39.62%	40.57%	42.51%	44.40%
	Total	24,652,000	25,695,000	23,968,000	21,112,000		Total	100.00%	100.00%	100.00%	100.00%
ETR						ETR					
	Short Term Debt	738,062	706,853	369,284	913,205		Short Term Debt	3.53%	3.45%	1.57%	4.58%
	Long-Term Debt	11,215,692	11,517,382	14,894,748	11,413,669		Long-Term Debt	53.68%	56.18%	63.24%	57.18%
	Preferred Stock	311,033	311,029	311,023	311,019		Preferred Stock	1.49%	1.52%	1.32%	1.56%
	Common Equity	8,630,406	7,966,592	7,976,923	7,322,805		Common Equity	41.30%	38.86%	33.87%	36.69%
	Total	20,895,193	20,501,856	23,551,978	19,960,698		Total	100.00%	100.00%	100.00%	100.00%
FE						FE					
	Short Term Debt	4,541,000	4,873,000	4,901,000	5,116,000		Short Term Debt	20.19%	21.90%	21.42%	22.30%
	Long-Term Debt	9,697,000	9,100,000	8,674,000	8,603,000		Long-Term Debt	43.12%	40.89%	37.92%	37.50%
	Preferred Stock						Preferred Stock	0.00%	0.00%	0.00%	0.00%
	Common Equity	8,250,000	8,283,000	9,301,000	9,221,000		Common Equity	36.69%	37.22%	40.66%	40.20%
	Total	22,488,000	22,256,000	22,876,000	22,940,000		Total	100.00%	100.00%	100.00%	100.00%
FPL						FPL					
	Short Term Debt	3,484,000	4,523,000	4,554,000	4,468,000		Short Term Debt	11.31%	14.95%	15.56%	15.97%
	Long-Term Debt	15,317,000	14,051,000	13,188,000	12,895,000		Long-Term Debt	49.73%	46.44%	45.05%	46.09%
	Preferred Stock						Preferred Stock	0.00%	0.00%	0.00%	0.00%
	Common Equity	11,999,000	11,681,000	11,534,000	10,614,000		Common Equity	38.96%	38.61%	39.40%	37.94%
	Total	30,800,000	30,255,000	29,276,000	27,977,000		Total	100.00%	100.00%	100.00%	100.00%
NU						NU					
	Short Term Debt	655,421	774,102	622,648	177,184		Short Term Debt	6.56%	8.15%	6.77%	2.01%
	Long-Term Debt	5,875,179	5,702,099	5,560,685	5,703,694		Long-Term Debt	58.83%	60.04%	60.45%	64.67%
	Preferred Stock						Preferred Stock	0.00%	0.00%	0.00%	0.00%
	Common Equity	3,456,072	3,020,312	3,015,981	2,939,456		Common Equity	34.61%	31.80%	32.78%	33.33%
	Total	9,986,672	9,496,513	9,199,314	8,820,334		Total	100.00%	100.00%	100.00%	100.00%
PCG						PCG					
	Short Term Debt	759,000	1,257,000	2,301,000	756,000		Short Term Debt	3.43%	5.83%	11.05%	4.29%
	Long-Term Debt	10,705,000	10,254,000	9,126,000	7,721,000		Long-Term Debt	48.38%	47.57%	43.82%	43.79%
	Preferred Stock	258,000	258,000	258,000	258,000		Preferred Stock	1.17%	1.20%	1.24%	1.46%
	Common Equity	10,404,000	9,787,000	9,139,000	8,897,000		Common Equity	47.02%	45.40%	43.89%	50.46%
	Total	22,126,000	21,556,000	20,824,000	17,632,000		Total	100.00%	100.00%	100.00%	100.00%
PGN						PGN					
	Short Term Debt	1,286,000	1,543,000	895,000	1,613,000		Short Term Debt	5.68%	7.15%	4.43%	7.76%
	Long-Term Debt	12,014,000	11,159,000	10,389,000	10,393,000		Long-Term Debt	53.03%	51.72%	51.42%	49.97%
	Preferred Stock	93,000	93,000	93,000	93,000		Preferred Stock	0.41%	0.43%	0.46%	0.45%
	Common Equity	9,261,000	8,780,000	8,827,000	8,700,000		Common Equity	40.88%	40.70%	43.69%	41.83%
	Total	22,654,000	21,575,000	20,204,000	20,799,000		Total	100.00%	100.00%	100.00%	100.00%
SO						SO					
	Short Term Debt	1,040,790	878,000	1,076,285	947,837		Short Term Debt	3.20%	2.80%	3.21%	3.19%
	Long-Term Debt	17,805,963	16,816,000	18,697,834	15,582,929		Long-Term Debt	54.83%	53.65%	55.73%	52.51%
	Preferred Stock	374,496	374,496	374,496	374,496		Preferred Stock	1.15%	1.19%	1.12%	1.26%
	Common Equity	13,252,708	13,276,000	13,404,056	12,770,473		Common Equity	40.81%	42.36%	39.95%	43.03%
	Total	32,473,957	31,344,496	33,552,671	29,675,735		Total	100.00%	100.00%	100.00%	100.00%
XEL						XEL					
	Short Term Debt	953,865	1,089,561	1,384,437	1,534,615		Short Term Debt	5.88%	6.67%	8.51%	9.83%
	Long-Term Debt	8,010,693	8,072,490	7,825,158	7,485,934		Long-Term Debt	49.38%	49.42%	48.10%	47.97%
	Preferred Stock	104,980	104,980	104,980	104,980		Preferred Stock	0.65%	0.64%	0.65%	0.67%
	Common Equity	7,154,062	7,068,721	6,953,320	6,479,450		Common Equity	44.10%	43.27%	42.74%	41.52%
	Total	16,223,600	16,335,752	16,267,895	15,604,979		Total	100.00%	100.00%	100.00%	100.00%
						Summary		3/31/09	12/31/08	9/30/08	6/30/08
							Short Term Debt	7.82%	8.91%	8.86%	8.40%
							Long-Term Debt	51.30%	50.63%	50.47%	49.95%
							Preferred Stock	0.85%	0.85%	0.86%	0.97%
							Common Equity	40.03%	39.61%	39.82%	40.68%
							Total	100.00%	100.00%	100.00%	100.00%

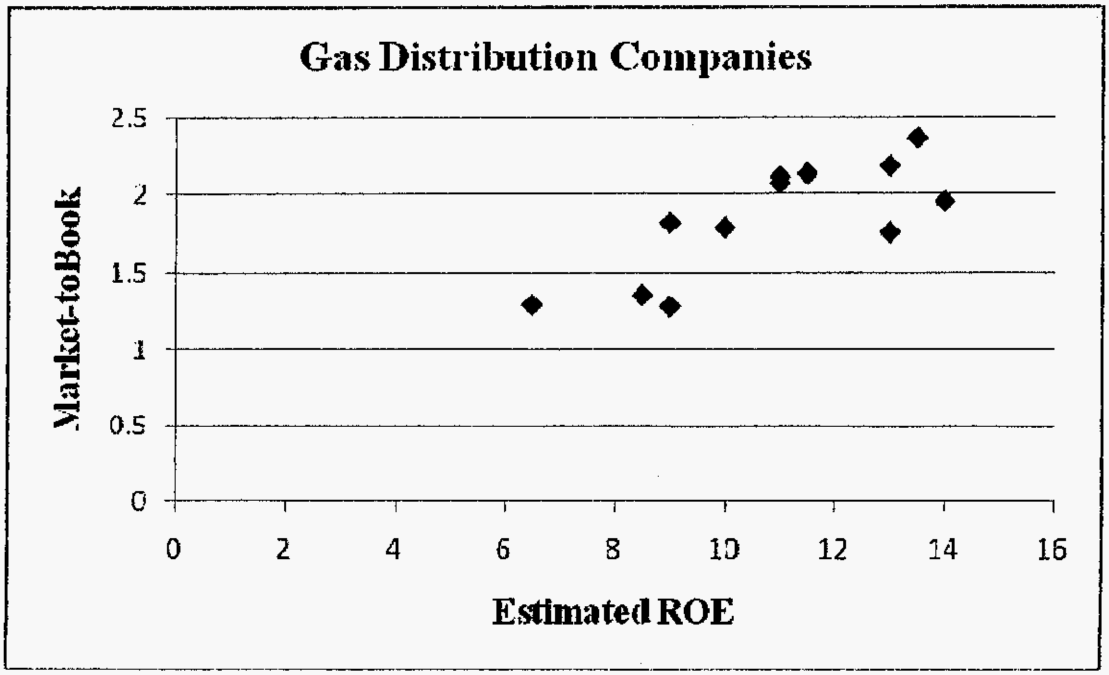
Exhibit JRW-6

Panel A



R-Square = .65, N=56.

Panel B



R-Square = .60, N=12.

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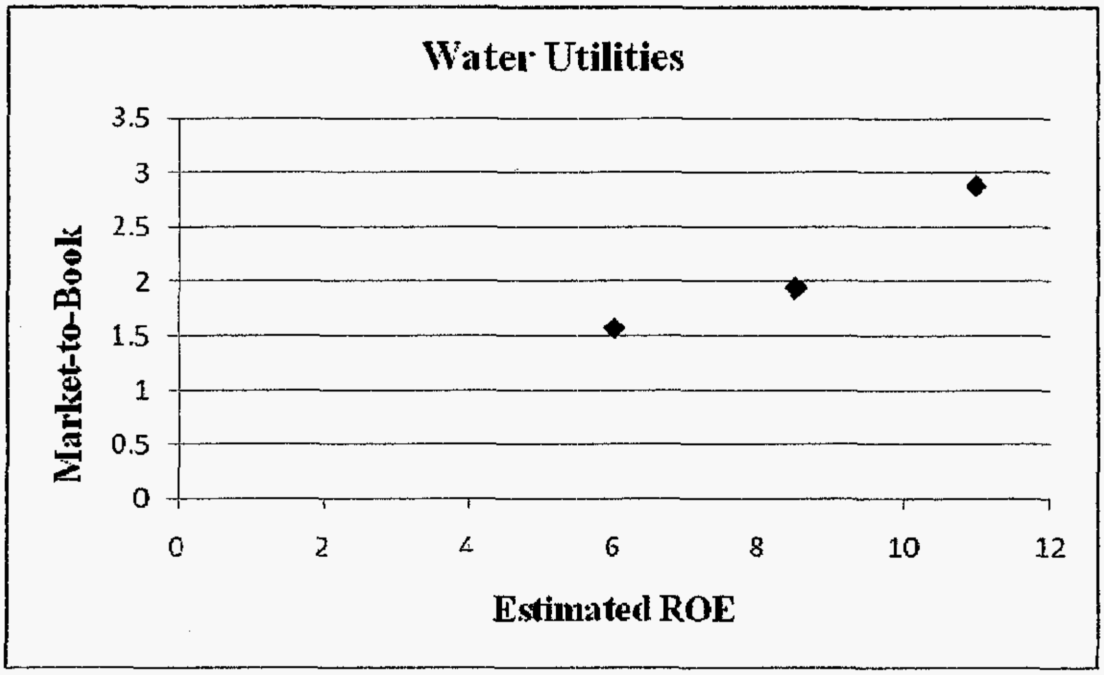
COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Dr. J. Randall Woolridge (JRW-6)
DATE 09/03/09

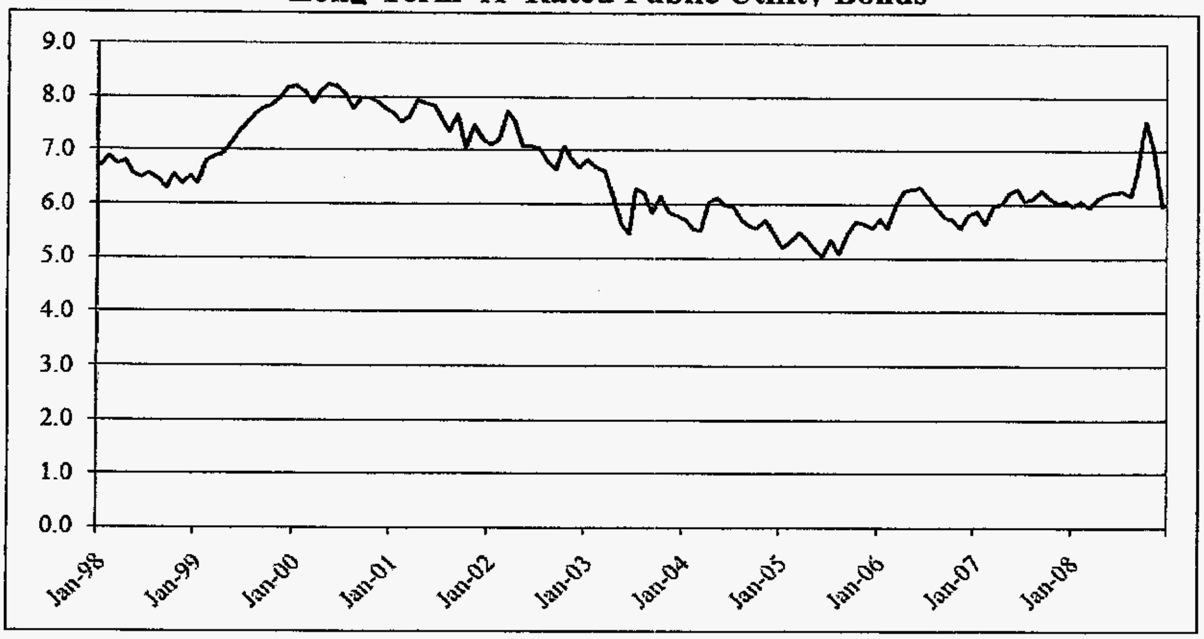
Exhibit JRW-6

Panel C



R-Square = .92, N=4.

Exhibit JRW-7
Long-Term 'A' Rated Public Utility Bonds



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 080677-EI & 090130-EI EXHIBIT 214
COMPANY Office of Public Counsel (OPC) (Direct)
WITNESS Dr. J. Randall Woolridge (JRW-7)
DATE 09/03/09