BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 110001-EI

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR.
_______________________________/

VOLUME 2

Pages 168 through 387

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN ART GRAHAM
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER RONALD A. BRISÉ
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

DATE: Tuesday, November 1, 2011

TIME: Commenced at 9:30 a.m.
Concluded at 11:45 a.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: LINDA BOLES, RPR, CRR
Official FPSC Reporter
(850) 413-6734

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID	ADMTD.
1	(CONFIDENTIAL) Comprehensive Exhibit List	318	318
2	(CONFIDENTIAL) GJY-1	318	318
3	(CONFIDENTIAL) GJY-2	318	318
4	(CONFIDENTIAL) GJY-3	318	318
5	GJY-4	318	318
6	TJK-1	318	318
7	(CONFIDENTIAL) TJK-2	318	318
8	TJK-3	318	318
9	TJK-4	318	318
10	TJK-5	318	318
11	TJK-6	318	318
12	TJK-7	318	318
13	(CONFIDENTIAL) TJK-8	318	318
14	TJK-9	318	318
14A	TJK-10	318	318
15	CP-1	318	318
16	JCB-1	318	318
17	WG-1T	318	
18	WG-2T	318	
19	(CONFIDENTIAL) WG-3T	318	
20	WG-4T	318	
21	RMO-1T	318	

EXHIBITS

NUMBER:		ID.	ADMTD.
22	ROM-1P	318	
23	(CONFIDENTIAL) JM-1T	318	318
24	(CONFIDENTIAL) JM-1P	318	318
25	(CONFIDENTIAL) JM-2P	318	
26	(CONFIDENTIAL) MO-1	318	
27	(CONFIDENTIAL) MO-2	318	
27A	MO-2 Revised	318	
28	CDY-1	318	318
29	CDY-2	318	318
30	CMM-1	318	384
31	(CONFIDENTIAL) HRB-1	318	318
32	HRB-2	318	318
33	(CONFIDENTIAL) HRB-3	318	318
34	(CONFIDENTIAL) HRB-4	318	318
35	(CONFIDENTIAL) RWD-1	318	318
36	(CONFIDENTIAL) RWD-2	318	318
37	(CONFIDENTIAL) RWD-3	318	318
38	(CONFIDENTIAL) RWD-4	318	318
39	MAY-1	318	318
40	MAY-2	318	318
41	(CONFIDENTIAL) CA-1 (Composite)	318	318
42	(CONFIDENTIAL) CA-2 (Composite)	318	318

EXHIBITS

NUMBER:		ID.	ADMTD.
43	(CONFIDENTIAL) CA-3 (Composite)	318	318
44	BSB-1	318	318
45	BSB-2	318	318
46	BSB-3	318	318
47	(CONFIDENTIAL) JBC-1	318	318
48	(CONFIDENTIAL) JBC-2	318	318
49	(CONFIDENTIAL) JBC-3	318	318
50	RAM-1	318	318
51	KLW-1	318	318
52	KLW-2	318	318
53	DDB-1	318	318
54	TK-1	318	318
55	(CONFIDENTIAL) Staff's Exhibit 55	318	
56	Staff's Exhibit 56	318	
57	(CONFIDENTIAL) Staff's Exhibit 57	318	
58	Staff's Exhibit 58	318	
59	Staff's Exhibit 59	318	
60	Staff's Exhibit 60	318	
61	(CONFIDENTIAL) Staff's Exhibit 61	318	
62	Staff's Exhibit 62	318	
63	(CONFIDENTIAL) Staff's Exhibit 63	318	
64	(CONFIDENTIAL) Staff's Exhibit 64	318	
65	Staff's Exhibit 65	318	

EXHIBITS

NUMBER:		ID.	ADMTD.
66	(CONFIDENTIAL) Staff's Exhibit 66	318	
67	(CONFIDENTIAL) Staff's Exhibit 67	318	
68	Staff's Exhibit 68	318	
69	(CONFIDENTIAL) Staff's Exhibit 69	318	
70	(CONFIDENTIAL) Staff's Exhibit 70	318	
71	(CONFIDENTIAL) Staff's Exhibit 71	318	
72	(CONFIDENTIAL) Staff's Exhibit 72	318	
73	Staff's Exhibit 73	318	
74	Staff's Exhibit 74	318	
75	Staff's Exhibit 75	318	
76	Staff's Exhibit 76	318	
77	Staff's Exhibit 77	318	
78	Staff's Exhibit 78	318	
79	Staff's Exhibit 79	318	
80	Staff's Exhibit 80	318	
81	Staff's Exhibit 81	318	
82	Staff's Exhibit 82	318	
83	Staff's Exhibit 83	318	
84	Staff's Exhibit 84	318	
85	Staff's Exhibit 85	318	
86	Stipulated Issues Checklist	345	345
87	Non-Stipulated Issues Checklist	345	345
88	FPUC Response to POD-1	382	384

P R O C E E D I N G S

(Transcript follows in sequence from Volume 2.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 110001-EI
Date of Filing: March 1, 2011

Q. Please state your name, business address and occupation.

A. My name is Richard Dodd. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Rates and Regulatory Matters at Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of West Florida in Pensacola, Florida in 1991 with a Bachelor of Arts Degree in Accounting. I also received a Bachelor of Science Degree in Finance in 1998 from the University of West Florida. I joined Gulf Power in 1987 as a Co-op Accountant and worked in various areas until I joined the Rates and Regulatory Matters area in 1990. After spending one year in the Financial Planning area, I transferred to Georgia Power Company in 1994 where I worked in the Regulatory Accounting department and in 1997 I transferred to Mississippi Power Company where I worked in the Rate and Regulation Planning department for six years followed by one year in Financial Planning. In 2004 I returned to Gulf Power Company working in the General Accounting area as Internal Controls Coordinator.

In 2007 I was promoted to Internal Controls Supervisor and in July 2008, I assumed my current position in the Rates and Regulatory Matters area. My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters Department.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the actual true-up amounts for the period January 2010 through December 2010 for both the Fuel and Purchased Power Cost Recovery Clause and the Capacity Cost Recovery Clause. I will also present the actual benchmark level for the calendar year 2011 gains on non-separated wholesale energy sales eligible for a shareholder incentive and the amount of gains or losses from hedging settlements for the period January 2010 through December 2010.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes. My exhibit consists of 1 schedule that relates to the fuel and purchased power cost recovery actual true-up, 4 schedules that relate to the capacity cost recovery actual true-up, and 1 appendix that includes Schedules A-1 through A-9 and A-12 for the period January 2010 through December 2010, previously filed monthly with this Commission. Each of these documents was prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Dodd's exhibit consisting of 5 schedules and 1 appendix be marked as Exhibit No. _____ (RWD-1).

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes.

Q. Which schedules of your exhibit relate to the calculation of the fuel and purchased power cost recovery true-up amount?

A. Schedule 1 of my exhibit relates to the fuel and purchased power cost recovery true-up calculation for the period January 2010 through December 2010. In addition, Fuel Cost Recovery Schedules A-1 through A-9 for January 2010 through December 2010 are incorporated herein in Appendix 1.

Q. What is the actual fuel and purchased power cost true-up amount related to the period of January 2010 through December 2010 to be refunded or collected through the fuel cost recovery factors in the period January 2012 through December 2012?

A. A net amount to be collected of $3,609,728 was calculated as shown on Schedule 1 of my exhibit.

Q. How was this amount calculated?

A. The $3,609,728 was calculated by taking the difference in the estimated and actual under-recovery amounts for the period January 2010 through December 2010. The estimated under-recovery was $23,786,207 as shown on Schedule E-1A, Line 1 filed August 2, 2010 and approved in FPSC Order No. PSC-10-0734-FOF-EI issued on December 20, 2010. The actual under-recovery was $27,395,935 which is the sum of the Period-to-Date amounts on lines 7, 8, and 12 shown on the December 2010 Schedule A-2, page 2 of 3, included in Appendix 1. Additional details supporting the approved estimated true-up amount are included on Schedules E1-A and E1-B filed August 2, 2010.

Q. Mr. Dodd, has the benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for actual 2010 gains?

A. Yes, the three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2008 through 2010 is calculated as follows:

Year	Actual Gain
2008	1,228,671
2009	982,077
2010	802,338
Three-Year Average	$1,004,362

Q. What is the actual threshold for 2011?

A. The actual threshold for 2011 is $1,004,362.

Q. Is Gulf seeking to recover any gains or losses from hedging settlements for the period of January 2010 through December 2010?

A. Yes. On line 2 of Schedule A-1, Period-to-Date, for December 2010 included in Appendix 1, Gulf has recorded a net loss of $19,667,161 related to hedging activities in 2010. Mr. Ball addresses the details of those hedging activities in his testimony.

Q. Mr. Dodd, you stated earlier that you are responsible for the purchased power capacity cost recovery true-up calculation. Which schedules of your exhibit relate to the calculation of this amount?

A. Schedules CCA-1, CCA-2, CCA-3 and CCA-4 of my exhibit relate to the purchased power capacity cost recovery true-up calculation for the period January 2010 through December 2010. In addition, Capacity Cost Recovery Schedule A-12 for the months of January 2010 through December 2010 is included in Appendix 1.

Q. What is the actual purchased power capacity cost true-up amount related to the period of January 2010 through December 2010 to be refunded or collected in the period January 2012 through December 2012?

A. An amount to be refunded of $1,217,382 was calculated as shown on Schedule CCA-1 of my exhibit.

Q. How was this amount calculated?

A. The $1,217,382 was calculated by taking the difference in the estimated January 2010 through December 2010 over-recovery of $545,466 and the actual over-recovery of $1,762,848, which is the sum of lines 10, 11, and 14 under the total column of Schedule CCA-2. The estimated true-up amount for this period was approved in FPSC Order No. PSC-10-0734-FOF-EI dated December 20, 2010. Additional details supporting the approved estimated true-up amount are included on Schedules CCE-1A and CCE-1B filed August 2, 2010.

Q. Please describe Schedules CCA-2 and CCA-3 of your exhibit.

A. Schedule CCA-2 shows the calculation of the actual over-recovery of purchased power capacity costs for the period January 2010 through December 2010. Schedule CCA-3 of my exhibit is the calculation of the interest provision on the over-recovery for the period January 2010 through December 2010. This is the same method of calculating interest that is used in the Fuel and Purchased Power (Energy) Cost Recovery Clause and the Environmental Cost Recovery Clause.

Q. Please describe Schedule CCA-4 of your exhibit.

A. Schedule CCA-4 provides additional details related to Lines 1 and 2 of Schedule CCA-2.

Q. Mr. Dodd, does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 110001-EI

BEFORE me, the undersigned authority, personally appeared Richard W. Dodd, who being first duly sworn, deposes and says that he is the Rates & Regulatory Matters Supervisor for Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge, information and belief. He is personally known to me.

Richard W Dodd

Richard W. Dodd
Rates & Regulatory Matters Supervisor

Sworn to and subscribed before me
this 28th day of February, 2011.

Vickie L. Marchman

Notary Public, State of Florida at Large

(SEAL)

NOTARY PUBLIC STATE OF FLORIDA
Vickie L. Marchman
COMMISSION # DD866249
EXPIRES: JUN. 26, 2013
WWW.AARONNOTARY.com

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 110001-EI
Date of Filing: August 3, 2011

Q. Please state your name, business address and occupation.

A. My name is Richard Dodd. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Rates and Regulatory Matters at Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of West Florida in Pensacola, Florida in 1991 with a Bachelor of Arts Degree in Accounting. I also received a Bachelor of Science Degree in Finance in 1998 from the University of West Florida. I joined Gulf Power in 1987 as a Co-op Accountant and worked in various areas until I joined the Rates and Regulatory Matters area in 1990. After spending one year in the Financial Planning area, I transferred to Georgia Power Company in 1994 where I worked in the Regulatory Accounting department and in 1997 I transferred to Mississippi Power Company where I worked in the Rate and Regulation Planning department for six years followed by one year in Financial Planning. In 2004 I returned to Gulf Power Company working in the General Accounting area as Internal Controls Coordinator. In 2007 I was promoted to Internal Controls Supervisor and in July 2008, I assumed my current position in the Rates and Regulatory Matters area.

My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters Department.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes, I have.

Counsel: We ask that Mr. Dodd's Exhibit consisting of fourteen schedules be marked as Exhibit No. ____ (RWD-2).

Q. Are you familiar with the Fuel and Purchased Power (Energy) estimated true-up calculations for the period of January 2011 through December 2011 and the Purchased Power Capacity Cost estimated true-up calculations for the period of January 2011 through December 2011 set forth in your exhibit?

A. Yes, these documents were prepared under my supervision.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes, I have.

Q. How were the estimated true-ups for the current period calculated for both fuel and purchased power capacity?

A. In each case, the estimated true-up calculations include six months of actual data and six months of estimated data.

Q. Mr. Dodd, what has Gulf calculated as the fuel cost recovery true-up to be applied in the period January 2012 through December 2012?

A. The fuel cost recovery true-up for this period is an increase of 0.1024 ¢/kWh. As shown on Schedule E-1A, this includes an estimated under-recovery for the January through December 2011 period of $8,441,457. It also includes a final under-recovery for the January through December 2010 period of $3,609,728 (see Schedule 1 of Exhibit RWD-1 in this docket filed on March 1, 2011). The resulting total under-recovery of $12,051,185 will be included for recovery during 2012.

Q. Mr. Dodd, you stated earlier that you are responsible for the Purchased Power Capacity Cost true-up calculation. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedules CCE-1A, CCE-1B and CCE-4 of my exhibit relate to the Purchased Power Capacity Cost true-up calculation to be applied in the January 2012 through December 2012 period.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2012 through December 2012?

A. The true-up for this period is a decrease of 0.0348 ¢/kWh as shown on Schedule CCE-1A. This includes an estimated over-recovery of $2,881,393 for January 2011 through December 2011. It also includes a final over-recovery of $1,217,382 for the period of January 2010 through December 2010 (see Schedule CCA-1 of Exhibit RWD-1 in this docket filed March 1, 2011). The resulting total over-recovery of $4,098,775 will be included for refund during 2012.

Q. Mr. Dodd, does this conclude your testimony?
A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 110001-EI
Date of Filing: September 1, 2011

Q. Please state your name, business address and occupation.

A. My name is Richard Dodd. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Rates and Regulatory Matters at Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of West Florida in Pensacola, Florida in 1991 with a Bachelor of Arts Degree in Accounting. I also received a Bachelor of Science Degree in Finance in 1998 from the University of West Florida. I joined Gulf Power in 1987 as a Co-op Accountant and worked in various areas until I joined the Rates and Regulatory Matters area in 1990. After spending one year in the Financial Planning area, I transferred to Georgia Power Company in 1994 where I worked in the Regulatory Accounting department and in 1997 I transferred to Mississippi Power Company where I worked in the Rate and Regulation Planning department for six years followed by one year in Financial Planning. In 2004 I returned to Gulf Power Company working in the General Accounting area as Internal Controls Coordinator.

In 2007 I was promoted to Internal Controls Supervisor and in July 2008, I assumed my current position in the Rates and Regulatory Matters area. My responsibilities include supervision of tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters Department.

Q. Have you previously filed testimony before this Commission in this on-going docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the calculation of Gulf Power's fuel cost recovery factors for the period January 2012 through December 2012. I will also discuss the calculation of the purchased power capacity cost recovery factors for the period January 2012 through December 2012.

Q. Have you prepared any exhibits that contain information to which you will refer in your testimony?

A. Yes. I have two exhibits consisting of 16 schedules, each of which was prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Dodd's first exhibit consisting of 15 schedules, be marked as Exhibit No. _____(RWD-3) and the second exhibit consisting of 1 schedule be marked as Exhibit No._____(RWD-4).

Q. Mr. Dodd, what is the levelized projected fuel factor for the period January 2012 through December 2012?

A. Gulf has proposed a levelized fuel factor of 4.943¢/kWh. This factor is based on projected fuel and purchased power energy expenses for January 2012 through December 2012 and projected kWh sales for the same period, and includes the true-up and GPIF amounts.

Q. How does the levelized fuel factor for the projection period compare with the levelized fuel factor for the current period?

A. The projected levelized fuel factor for 2012 is 0.161¢/kWh less or 3.15 percent lower than the levelized fuel factor in place January 2011 through December 2011.

Q. Please explain the calculation of the fuel and purchased power expense true-up amount included in the levelized fuel factor for the period January 2012 through December 2012.

A. As shown on Schedule E-1A of my exhibit, the true-up amount of $12,051,185 to be collected during 2012 includes an estimated under-recovery for the January through December 2011 period of $8,441,457, plus a final under-recovery for the period January through December 2010 of $3,609,728. The estimated under-recovery for the January through December 2011 period includes 6 months of actual data and 6 months of estimated data as reflected on Schedule E-1B.

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of January 2010 through December 2010?

A. The GPIF result is shown on Line 31 of Schedule E-1 as an increase of 0.0055¢/kWh to the levelized fuel factor, thereby rewarding Gulf $645,511.

Q. What is the appropriate revenue tax factor to be applied in calculating the levelized fuel factor?

A. A revenue tax factor of 1.00072 has been applied to all jurisdictional fuel costs as shown on Line 29 of Schedule E-1.

Q. Mr. Dodd, how were the line loss multipliers used on Schedule E-1E calculated?

A. The line loss multipliers were calculated in accordance with procedures approved in prior filings and were based on Gulf's latest MWh Load Flow Allocators.

Q. Mr. Dodd, what fuel factor does Gulf propose for its largest group of customers (Group A), those on Rate Schedules RS, GS, GSD, and OSIII?

A. Gulf proposes a standard fuel factor, adjusted for line losses, of 4.969¢/kWh for Group A. Fuel factors for Groups A, B, C, and D are shown on Schedule E-1E. These factors have all been adjusted for line losses.

Q. Mr. Dodd, how were the time-of-use fuel factors calculated?

A. The time-of-use fuel factors were calculated based on projected loads and system lambdas for the period January 2012 through December 2012. These factors included the GPIF and true-up and were adjusted for line losses. These time-of-use fuel factors are also shown on Schedule E-1E.

Q. How does the proposed fuel factor for Rate Schedule RS compare with the factor applicable to December 2011 and how would the change affect the cost of 1,000 kWh on Gulf's residential rate RS?

A. The current fuel factor for Rate Schedule RS applicable through December 2011 is 5.131¢/kWh compared with the proposed factor of 4.969¢/kWh. For a residential customer who uses 1,000 kWh in January 2012, the fuel portion of the bill would decrease from $51.31 to $49.69.

Q. Has Gulf updated its estimates of the as-available avoided energy costs to be shown on COG1 as required by Order No. 13247 issued May 1, 1984, in Docket No. 830377-EI and Order No. 19548 issued June 21, 1988, in Docket No. 880001-EI?

A. Yes. A tabulation of these costs is set forth in Schedule E-11 of my exhibit. These costs represent the estimated averages for the period from January 2012 through December 2013.

Q. What amount have you calculated to be the appropriate benchmark level for calendar year 2012 gains on non-separated wholesale energy sales eligible for a shareholder incentive?

A. In accordance with Order No. PSC-00-1744-AAA-EI, a benchmark level of $868,270 has been calculated for 2012 as follows:

2009 actual gains	982,077
2010 actual gains	809,781
2011 estimated gains	812,951
Three-Year Average	$868,270

This amount represents the minimum projected threshold for 2012 that must be achieved before shareholders may receive any incentive. As demonstrated on Schedule E-6, page 2 of 2, Gulf's projection reflects a credit to customers of 100 percent of the gains on non-separated sales for 2012 for the months of January through December.

Q. You stated earlier that you are responsible for the calculation of the purchased power capacity cost (PPCC) recovery factors. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedule CCE-1, including CCE-1A and CCE-1B, Schedule CCE-2, and Schedule CCE-4 for 2012 of my exhibit RWD-3 relate to the calculation of the PPCC recovery factors for the period January 2012 through December 2012.

Q. Please describe Schedule CCE-1 of your exhibit.

A. Schedule CCE-1 shows the calculation of the amount of capacity payments to be recovered through the PPCC Recovery Clause. Mr. Ball has provided me with Gulf's projected purchased power capacity transactions. Gulf's total projected net capacity expense, which includes a credit for transmission revenue, for the period January 2012 through December 2012 is $48,106,587. The jurisdictional amount is $46,396,792. This amount is added to the total true-up amount to determine the total purchased power capacity transactions that would be recovered in the period.

Q. What methodology was used to allocate the capacity payments by rate class?

A. As required by Commission Order No. 25773 in Docket No. 910794-EQ, the revenue requirements have been allocated using the cost of service methodology used in Gulf's last rate case and approved by the Commission in Order No. PSC-02-0787-FOF-EI issued June 10, 2002, in Docket No. 010949-EI. For purposes of the PPCC Recovery Clause, Gulf has allocated the net purchased power capacity costs by rate class with 12/13th on demand and 1/13th on energy. This allocation is consistent with the treatment accorded to production plant in the cost of service study used in Gulf's last rate case.

Q. How were the allocation factors calculated for use in the PPCC Recovery Clause?

A. The allocation factors used in the PPCC Recovery Clause have been calculated using the 2009 load data filed with the Commission in accordance with FPSC Rule 25-6.0437. The calculations of the allocation factors are shown in columns A through I on page 1 of Schedule CCE-2.

Q. Please describe the calculation of the ¢/kWh factors by rate class used to recover purchased power capacity costs.

A. As shown in columns A through D on page 2 of Schedule CCE-2, 12/13th of the jurisdictional capacity cost to be recovered is allocated by rate class based on the demand allocator. The remaining 1/13th is allocated based on energy.

The total revenue requirement assigned to each rate class shown in column E is then divided by that class's projected kWh sales for the twelve-month period to calculate the PPCC recovery factor. This factor would be applied to each customer's total kWh to calculate the amount to be billed each month.

Q. What is the amount related to purchased power capacity costs recovered through this factor that will be included on a residential customer's bill for 1,000 kWh?

A. The purchased power capacity costs recovered through the clause for a residential customer who uses 1,000 kWh will be $3.78.

Q. Have there been any revisions to any of the purchased power capacity schedules previously submitted in the 2011 Actual/Estimated True-up filing that are included in this Projection Filing for the period January 2012 through December 2012?

A. Yes. As indicated in the letter dated August 19, 2011 addressed to Marshall Willis, Director of the Division of Economic Regulation, Gulf now projects that a greater than 10 percent over-recovery of purchased power capacity costs is expected to occur for the period ending December 31, 2011. In that letter, Gulf proposed that the 2011 Estimated True-up component of the 2012 PPCC factor be revised so that this updated projected over-recovery balance could be refunded to customers in 2012 rather than waiting until 2013 which is when it would ordinarily be reflected in the cost recovery factors as part of the 2011 Final True-up. In this filing, Gulf has revised a number of schedules to reflect actual data for the month of July 2011 and a revised projection of purchased power capacity costs for the month of August 2011.

Q. Please discuss the schedules that have been revised.

A. Schedules CCE-1A and CCE-1B, which were included in the 2011 Actual/Estimated True-up filing have been revised to reflect actual July 2011 data along with revised cost estimates for August 2011. These revisions result in a True-up amount to be refunded to customers in 2012 of $8,397,106 which is $4,298,331 greater than the amount of $4,098,775 included in Gulf's 2011 Actual/Estimated True-up filing.

In addition, a revised Schedule CCE-4 for the period January through December 2011 has been provided to further support the revised July and August 2011 purchased power capacity cost data presented on Schedule CCE-1B. The revised Schedule CCE-4 is attached to my testimony as Exhibit___RWD-4.

Q. When does Gulf propose to collect these new fuel charges and purchased power capacity charges?

A. The fuel and capacity factors will be effective beginning with Cycle 1 billings in January 2012 and continuing through the last billing cycle of December 2012.

Q. Mr. Dodd, does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 110001-EI

BEFORE me, the undersigned authority, personally appeared Richard W. Dodd, who being first duly sworn, deposes and says that he is the Rates & Regulatory Matters Supervisor for Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge, information and belief. He is personally known to me.

Richard W. Dodd
Richard W. Dodd
Rates & Regulatory Matters Supervisor

Sworn to and subscribed before me this 30th day of August, 2011.

Candace Klinglesmith
Notary Public, State of Florida at Large

(SEAL)

CANDACE KLINGLESMITH
Notary Public - State of Florida
My Comm. Expires May 18, 2015
Commission # EE 79408
Bonded Through National Notary Assn.

GULF POWER COMPANY

Before the Florida Public Service Commission

Direct Testimony and Exhibit of

M. A. Young, III

Docket No. 110001-EI

Date of Filing: March 15, 2011

Q. Please state your name, address, and occupation.

A. My name is Melvin A. Young, III. My business address is One Energy Place, Pensacola, Florida 32520-0335. My current job position is Power Generation Specialist, Senior for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Mechanical Engineering from the University of Alabama in Birmingham in 1984. I joined the Southern Company with Alabama Power in 1981 as a co-op student and continued with Alabama Power upon graduation in 1984. During my time at Alabama Power, I worked at Plant Gorgas, Plant Gadsden and in Power Generation Services where I progressed through various engineering positions with increasing responsibilities as well as first line supervision in Operations and Maintenance. I joined Gulf Power in 1997 as the Performance Engineer at Plant Crist. My primary responsibilities have been to monitor and test plant equipment and monitor overall plant heat rate. In addition to this, I have been responsible for major plant projects and was the primary reliability reporter. As previously mentioned in my testimony, my current job position is Power Generation Specialist, Senior at Gulf Power Company.

In this position, I am responsible for preparing all Generating Performance Incentive Factor (GPIF) filings as well as other generating plant reliability and heat rate performance reporting for Gulf Power Company.

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

A. The purpose of my testimony is to present GPIF results for Gulf Power Company for the period of January 1, 2010, through December 31, 2010.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes. I have prepared an exhibit consisting of five schedules.

Counsel: We ask that Mr. Young's Exhibit, consisting of five schedules, be marked for identification as Exhibit_____ MAY-1.

Q. Is there any information that has been supplied to the Commission pertaining to this GPIF period that requires amendment?

A. Yes. Some corrections have been made to the actual unit performance data, which was submitted monthly to the Commission during this time period. These corrections are based on discoveries made during the final data review to ensure the accuracy of the information reported in this filing. The actual unit performance data tables on pages 16 through 31 of Schedule 5 of my exhibit incorporate these changes. The data contained in these tables is the data upon which the GPIF calculations were made.

Q. Please review the Company's equivalent availability results for the period.

A. Actual equivalent availability and adjusted actual equivalent availability figures for each of the Company's GPIF units are shown on page 15 of Schedule 5. Pages 3 through 10 of Schedule 2 contain the calculations for the adjusted actual equivalent availabilities.

A calculation of GPIF availability points based on these availabilities and the targets established by FPSC Order No. PSC-09-0795-FOF-EI is on page 11 of Schedule 2. The results are: Crist 4, +10.00 points; Crist 5, +10.00 points; Crist 6, +2.73 points; Crist 7, +10.00 points; Smith 1, -5.26 points; Smith 2, -10.00 points; Daniel 1, +2.67 points; and Daniel 2, +10.00 points.

Q. What were the heat rate results for the period?

A. The detailed calculations of the actual average net operating heat rates for the Company's GPIF units are on pages 2 through 9 of Schedule 3.

As was done for the prior GPIF periods, and as indicated on pages 10 through 17 of Schedule 3, the target equations were used to adjust actual results to the target basis. These equations, submitted in September 2009, are shown on page 20 of Schedule 3. As calculated on page 21 of Schedule 3, the adjusted actual average net operating heat rates correspond to the following GPIF unit heat rate points: -10.00 for Crist 4, -10.00 for Crist 5, -10.00 for Crist 6, +6.04 for Crist 7, +1.20 for Smith 1, -4.68 for Smith 2, +10.00 for Daniel 1, and +10.00 for Daniel 2.

Q. What number of Company points was achieved during the period, and what reward or penalty is indicated by these points according to the GPIF procedure?

A. Using the unit equivalent availability and heat rate points previously mentioned, along with the appropriate weighting factors, the number of Company points achieved was +1.56 as indicated on page 2 of Schedule 4. This calculated to a reward in the amount of $645,511.

Q. Please summarize your testimony.

A. In view of the adjusted actual equivalent availabilities, as shown on page 11 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 21 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a reward in the amount of $645,511 as provided for by the GPIF plan.

Q. Does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 110001-EI

BEFORE me, the undersigned authority, personally appeared Melvin A. Young, III, who being first duly sworn, deposes and says that he is the Power Generation Specialist for Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge, information and belief. He is personally known to me.

M. A. Young III

Melvin A. Young, III
Power Generation Specialist

Sworn to and subscribed before me
this 14th day of March, 2011.

Linda C. Webb

Notary Public, State of Florida at Large

(SEAL)

NOTARY PUBLIC STATE OF FLORIDA

LINDA C. WEBB
Notary Public, State of Florida
Comm. Expi. May 31, 2014
Comm. No. DD 964189

GULF POWER COMPANY

Before the Florida Public Service Commission

Direct Testimony of

M. A. Young, III

Docket No. 110001-EI

Date of Filing: September 1, 2011

Q. Please state your name, address, and occupation.

A. My name is Melvin A. Young, III. My business address is One Energy Place, Pensacola, Florida 32520-0335. My current job position is Power Generation Specialist, Senior for Gulf Power Company.

Q. Please describe your educational and business background.

A. I received my Bachelor of Science degree in Mechanical Engineering from the University of Alabama in Birmingham in 1984. I joined the Southern Company with Alabama Power in 1981 as a co-op student and continued with Alabama Power upon graduation in 1984. During my time at Alabama Power, I worked at Plant Gorgas, Plant Gadsden and in Power Generation Services where I progressed through various engineering positions with increasing responsibilities as well as first line supervision in Operations and Maintenance. I joined Gulf Power in 1997 as the Performance Engineer at Plant Crist. In this capacity, my primary responsibilities were to monitor and test plant equipment and monitor overall plant heat rate. In addition to this, I was responsible for major plant projects and was the primary reliability reporter. As previously mentioned in my testimony, my current job position is Power Generation Specialist, Senior at Gulf Power Company.

In this position I am responsible for preparing all Generating Performance Incentive Factor (GPIF) filings as well as other generating plant reliability and heat rate performance reporting for Gulf Power Company.

Q. What is the purpose of your testimony in this proceeding?
A. The purpose of my testimony is to present GPIF targets for Gulf Power Company for the period of January 1, 2012 through December 31, 2012.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes. I have prepared one exhibit entitled MAY-2 consisting of three schedules.

Q. Was this exhibit prepared by you or under your direction and supervision?
A. Yes, it was.

Counsel: We ask that Mr. Young's exhibit consisting of three schedules be marked for identification as Exhibit___(MAY-2).

Q. Which units does Gulf propose to include under the GPIF for the subject period?
A. We propose that Crist Units 4, 5, 6, and 7, Smith Units 1 and 2, and Daniel Units 1 and 2, continue to be the Company's GPIF units. The projected net generation from these units, which represent all of Gulf's qualifying base load units for GPIF, is approximately 71% of Gulf's projected net generation for 2012.

Q. For these units, what are the target heat rates Gulf proposes to use in the GPIF for these units for the performance period January 1, 2012 through December 31, 2012?

A. I would like to refer you to page 39 of Schedule 1 of my exhibit where these targets are listed.

Q. How were these proposed target heat rates determined?

A. They were determined according to the GPIF Implementation Manual procedures for Gulf.

Q. Describe how the targets were determined for Gulf's proposed GPIF units.

A. Page 2 of Schedule 1 of my exhibit shows the target average net operating heat rate equations for the proposed GPIF units and pages 4 through 35 of Schedule 1 contain the weekly historical data used for the statistical development of these equations. Pages 36 through 38 of Schedule 1 present the calculations that provide the unit target heat rates from the target equations.

Q. Were the maximum and minimum attainable heat rates for each proposed GPIF unit indicated on page 39 of Schedule 1 of your exhibit calculated according to the appropriate GPIF Implementation Manual procedures?

A. Yes.

Q. What are the proposed target, maximum, and minimum equivalent availabilities for Gulf's units?

A. The target, maximum, and minimum equivalent availabilities are listed on page 4 of Schedule 2 of my exhibit.

Q. How were the target equivalent availabilities determined?

A. The target equivalent availabilities were determined according to the standard GPIF Implementation Manual procedures for Gulf and are presented on page 2 of Schedule 2 of my exhibit.

Q. How were the maximum and minimum attainable equivalent availabilities determined for each unit?

A. The maximum and minimum attainable equivalent availabilities, which are presented along with their respective target availabilities on page 4 of Schedule 2 of my exhibit, were determined per GPIF Implementation Manual procedures for Gulf.

Q. Mr. Young, has Gulf completed the GPIF minimum filing requirements data package?

A. Yes, we have completed the minimum filing requirements data package. Schedule 3 of my exhibit contains this information.

Q. Mr. Young, would you please summarize your testimony?
A. Yes. Gulf asks that the Commission accept:

1. Crist Units 4, 5, 6 and 7, Smith Units 1 and 2, and Daniel Units 1 and 2 for inclusion under the GPIF for the period of January 1, 2012 through December 31, 2012.

2. The target, maximum attainable, and minimum attainable average net operating heat rates, as proposed by the Company and as shown on page 39 of Schedule 1 and also on page 5 of Schedule 3 of my exhibit.

3. The target, maximum attainable, and minimum attainable equivalent availabilities, as proposed by the Company and as shown on page 4 of Schedule 2 and also on page 5 of Schedule 3 of my exhibit.

4. The weekly average net operating heat rate least squares regression equations, shown on page 2 of Schedule 1 and also on pages 20 through 35 of Schedule 3 of my exhibit, for use in adjusting the annual actual unit heat rates to target conditions.

Q. Mr. Young, does this conclude your testimony?
A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 110001-EI

Before me, the undersigned authority, personally appeared Melvin A. Young, III, who being first duly sworn, deposes, and says that he is the Power Generation Specialist, Senior for Gulf Power Company, a Florida corporation, and that the foregoing is true and correct to the best of his knowledge, information, and belief. He is personally known to me.

M. A. Young III

Melvin A. Young, III
Power Generation Specialist, Senior

Sworn to and subscribed before me this 24th day of August, 2011.

Candace Klinglesmith

Notary Public, State of Florida at Large

CANDACE KLINGLESMITH
Notary Public - State of Florida
My Comm. Expires May 18, 2015
Commission # EE 79408
Bonded Through National Notary Assn.

Commission Number: EE79408

Commission Expires: 5-18-2015

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

Q. Please state your name, address, occupation and employer.

A. My name is Carlos Aldazabal. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Director, Regulatory Affairs in the Regulatory Affairs Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science Degree in Accounting in 1991, and received a Masters of Accountancy from the University of South Florida in Tampa in 1995. I am a CPA in the State of Florida and have accumulated 16 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, and budgeting and analysis. In April 1999, I joined Tampa Electric as Supervisor, Regulatory

Accounting. In January 2004, I became Manager Regulatory Affairs where my duties included managing cost recovery for fuel and purchased power, interchange sales, and capacity payments. In August 2009, I was promoted to Director Regulatory Affairs with primary responsibility for overseeing all of the cost recovery clauses.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for the Commission's review and approval, the final true-up amounts for the period January 2010 through December 2010 for the Fuel and Purchased Power Cost Recovery Clause ("Fuel Clause"), the Capacity Cost Recovery Clause ("Capacity Clause") as well as the wholesale incentive benchmark for January 2011 through December 2011.

Q. What is the source of the data which you will present by way of testimony or exhibit in this process?

A. Unless otherwise indicated, the actual data is taken from the books and records of Tampa Electric. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices and provisions of the Uniform System of Accounts as prescribed by the Florida Public Service Commission ("Commission").

Q. Have you prepared an exhibit in this proceeding?

A. Yes. Exhibit No.___ (CA-1), consisting of four documents which are described later in my testimony, was prepared under my direction and supervision.

Capacity Cost Recovery Clause

Q. What is the final true-up amount for the Capacity Clause for the period January 2010 through December 2010?

A. The final true-up amount for the Capacity Clause for the period January 2010 through December 2010 is an under-recovery of $461,060.

Q. Please describe Document No. 1 of your exhibit.

A. Document No. 1, page 1 of 4, entitled "Tampa Electric Company Capacity Cost Recovery Clause Calculation of Final True-up Variances for the Period January 2010 Through December 2010", provides the calculation for the final under-recovery of $461,060. The actual capacity cost under-recovery, including interest, was $514,151 for the period January 2010 through December 2010 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the $53,091 actual/estimated under-recovery approved in Order No. PSC-10-0734-FOF-EI issued December 20, 2010 in Docket No. 100001-EI, results in a final under-recovery for the period of $461,060 as identified in Document No. 1, page 4 of 4. This under-recovery amount will be applied in the calculation of the capacity cost recovery factors for the period January 2012 through December 2012.

Q. What is the estimated effect of this $461,060 under-recovery for the January 2010 through December 2010 period on residential bills during January 2012 through December 2012?

A. The $461,060 under-recovery will increase a 1,000 kWh residential bill by approximately $0.03.

Incremental Security Alert and NERC Cyber Expenses

Q. What were Tampa Electric's actual 2010 incremental O&M security alert and NERC cyber security expenses as a result of the events of September 11, 2001?

A. Tampa Electric included all of its existing incremental O&M security and NERC cyber security expenses for protecting its generating facilities into its rate case test year in Docket No. 080317-EI. Therefore, the base rates approved by the Commission, effective May 2009, included existing incremental O&M security and NERC Cyber security expenses. There were no new incremental O&M security or NERC cyber security expenses included for cost recovery in 2010.

Fuel and Purchased Power Cost Recovery Clause

Q. What is the final true-up amount for the Fuel Clause for the period January 2010 through December 2010?

A. The final Fuel Clause true-up for the period January 2010 through December 2010 is an over-recovery of $5,086,991. The actual fuel cost over-recovery, including interest, was $72,174,864 for the period January 2010 through December 2010. This $72,174,864 amount, less the $67,087,873 actual/estimated over-recovery amount approved in Order No. PSC-10-0734-FOF-EI, issued December 20, 2010 in Docket No. 100001-EI results in a net over-recovery amount for the period of $5,086,991.

Q. What is the estimated effect of the $5,086,991 over-recovery for the January 2010 through December 2010 period on residential bills during January 2012 through December 2012?

A. The $5,086,991 over-recovery would decrease a 1,000 kWh residential bill by approximately $0.27.

Q. Please describe Document No. 2 of your exhibit.

A. Document No. 2 is entitled "Tampa Electric Company Final Fuel and Purchased Power Over/(Under) Recovery for the Period January 2010 Through December 2010". It shows the calculation of the final fuel over-recovery of $5,086,991.

Line 1 shows the total company fuel costs of $866,926,117 for the period January 2010 through December 2010. The jurisdictional amount of total fuel costs is $854,351,178, as shown on line 2. This amount is compared to the jurisdictional fuel revenues applicable to the period on line 3 to obtain the actual over-recovered fuel costs for the period, shown on line 4. The resulting $54,940,547 over-recovered fuel costs for the period, combined with a true-up of the revenue refund as part of Tampa Electric's retail rate case stipulation and settlement agreement in Order No. PSC-10-0572-FOF-EI, issued on September 16, 2010 in Docket No. 090368-EI, interest, true-up collected and the prior period true-up shown on lines 5, 6, 7 and 8, respectively, constitute the actual over-recovery of $72,174,864 shown on line 9. The $72,174,864 actual over-recovery amount less the $67,087,873 actual/estimated over-recovery amount shown on line 10, results in a final $5,086,991 over-recovery amount for the period January 2010 through December 2010 as shown on line 11.

Q. Please describe Document No. 3 of your exhibit.

A. Document No. 3 entitled "Tampa Electric Company Calculation of True-up Amount Actual *vs.* Original Estimates for the Period January 2010 Through December 2010", shows the calculation of the actual over-recovery as compared to the estimate for the same period.

Q. What was the total fuel and net power transaction cost variance for the period January 2010 through December 2010?

A. As shown on line A7 of Document No. 3, the fuel and net power transaction cost variance is $67,950,177 less than what was originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2010 through December 2010?

A. As shown on line C3 of Document No. 3, the company collected $1,904,239 or 0.2 percent more jurisdictional fuel revenues than originally estimated.

Q. Please describe Document No. 4 of your exhibit.

A. Document No. 4 contains Commission Schedules A1 and A2 for the month of December and the year-end period-to-date summary of the transactions for each of Commission Schedules A6, A7, A8, A9 as well as capacity information on schedule A12.

Wholesale Incentive Benchmark

Q. What is Tampa Electric's wholesale incentive benchmark for 2011, as derived in accordance with Order No. PSC-01-2371-FOF-EI, Docket No. 010283-EI?

A. The company's 2011 benchmark is $2,719,531, which is the three-year average of $1,676,141, $3,533,488 and $2,948,964 actual gains on non-separated wholesale sales, excluding emergency sales, for 2008, 2009 and 2010, respectively.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

Q. Please state your name, address, occupation and employer.

A. My name is Carlos Aldazabal. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Director, Regulatory Affairs in the Regulatory Affairs Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science Degree in Accounting in 1991, and received a Masters of Accountancy in 1995 from the University of South Florida in Tampa. I am a CPA in the State of Florida and have accumulated 16 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, and budgeting and analysis. In April 1999, I joined Tampa Electric as Supervisor, Regulatory Accounting. In January 2004, I became Manager, Regulatory Affairs where my duties included managing cost recovery for fuel and purchased power, interchange sales, and capacity payments. In August 2009, I was promoted to Director Regulatory Affairs with primary responsibility for overseeing all cost recovery clauses.

Q. Have you previously testified before this Commission?

A. Yes. I have submitted written testimony in the annual fuel docket since 2004, and I testified before this Florida Public Service Commission ("FPSC" or "Commission") in Docket Nos. 060001-EI and 080001-EI regarding the appropriateness and prudence of Tampa Electric's recoverable fuel and purchased power costs as well as capacity costs.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, the proposed annual levelized fuel and purchased power cost recovery factors including an inverted or two-tiered residential fuel charge to encourage energy efficiency and conservation and the projected wholesale incentive benchmark for January 2012 through December 2012. I will also describe significant events that affect the factors and provide an overview of the composite effect from the various cost recovery factors for 2012.

Q. Have you prepared an exhibit to support your testimony?

A. Yes. Exhibit No. ____ (CA-3), consisting of three documents, was prepared under my direction and supervision. Document No. 1, consisting of four pages, is furnished as support for the projected capacity cost recovery factors utilizing the Commission approved allocation methodology from Order No. PSC-09-0283-FOF-EI issued April 30, 2009, in Docket No. 080317-EI based on 12 Coincident Peak ("CP") and 25 percent Average Demand ("AD"). Document No. 2, which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, is comprised of Schedules E1 through E10 for January 2012 through December 2012 as well as Schedule H1 for January through December, 2009 through 2012. Document No. 3 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate and a levelized fuel rate, which demonstrates that the tiered rate is revenue neutral.

Capacity Cost Recovery

Q. Are you requesting Commission approval of the projected capacity cost recovery factors for the company's various rate schedules?

A. Yes. The capacity cost recovery factors, prepared under my direction and supervision, are provided in Exhibit No. ____ (CA-3), Document No. 1, page 3 of 4. The capacity factors reflect the company's approved rate design from Order No. PSC-09-0283-FOF-EI in Docket No. 080317-EI, issued April 30, 2009.

Q. What payments are included in Tampa Electric's capacity cost recovery factors?

A. Tampa Electric is requesting recovery of capacity payments for power purchased for retail customers, excluding optional provision purchases for interruptible customers, through the capacity cost recovery factors. As shown in Exhibit No. ____ (CA-3), Document No. 1, Tampa Electric requests recovery of $44,995,474 after jurisdictional separation and prior year true-up, for estimated expenses in 2012.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2012 through December 2012.

A. Rate Class and Metering Voltage	Capacity Cost Cents per kWh	Recovery Factor $ per kW
RS Secondary	0.276	
GS and TS Secondary	0.256	
GSD, SBF Standard		
Secondary		0.86
Primary		0.85
Transmission		0.84
IS, IST, SBI		
Primary		0.68
Transmission		0.68
GSD Optional		
Secondary	0.203	
Primary	0.201	
LS1 Secondary	0.064	

These factors are shown in Exhibit No. _____ (CA-3), Document No. 1, page 3 of 4.

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.237 cents per kWh compare to the factor for January 2011 through December 2011?

A. The proposed capacity cost recovery factor is 0.054 cents per kWh (or $0.54 per 1,000 kWh) lower than the average capacity cost recovery factor of 0.291 cents per kWh for the January 2011 through December 2011 period.

Fuel and Purchased Power Cost Recovery Factor

Q. What is the appropriate amount of the levelized fuel and purchased power cost recovery factor for the year 2012?

A. The appropriate amount for the 2012 period is 4.190 cents per kWh before the application of time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. ____ (CA-3), Document No. 2, shows the appropriate value for the total fuel and purchased power cost recovery factor for each metering voltage level as projected for the period January 2012 through December 2012.

Q. Please describe the information provided on Schedule E1-C.

A. The Generating Performance Incentive Factor ("GPIF") and true-up factors are provided on Schedule E1-C. Tampa Electric has calculated a GPIF reward of $2,054,696, which is included in the calculation of the total fuel and purchased power cost recovery factors. Additionally, E1-C indicates the net true-up amount for the January 2011 through December 2011 period. The net true-up amount for this period is an over-recovery of $47,813,410.

Q. Please describe the information provided on Schedule E1-D.

A. Schedule E1-D presents Tampa Electric's on-peak and off-peak fuel adjustment factors for January 2012 through December 2012. The schedule also presents Tampa Electric's levelized fuel cost factors at each metering voltage level.

Q. Please describe the information provided on Schedule E1-E.

A. Schedule E1-E presents the standard, tiered, on-peak and off-peak fuel adjustment factors at each metering voltage to be applied to customer bills.

Q. Please describe the information provided in Document No. 3.

A. Exhibit No. ____ (CA-3), Document No. 3 demonstrates that the tiered rate structure is designed to be revenue neutral so that the company will recover the same fuel costs as it would under the traditional levelized fuel approach.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for January 2012 through December 2012.

A.

Metering Voltage Level	**Fuel Charge Factor (cents per kWh)**
Secondary	4.190
Tier I (Up to 1,000 kWh)	3.840
Tier II (Over 1,000 kWh)	4.840
Distribution Primary	4.148
Transmission	4.106
Lighting Service	4.129
Distribution Secondary	4.580 (on-peak)
	4.036 (off-peak)
Distribution Primary	4.534 (on-peak)
	3.996 (off-peak)
Transmission	4.488 (on-peak)
	3.955 (off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 4.190 cents per kWh compare to the levelized fuel adjustment factor for the January 2011 through December 2011 period?

A. The proposed fuel charge factor is 0.035 cents per kWh (or $0.35 per 1,000 kWh) lower than the average fuel charge factor of 4.225 cents per kWh for the January 2011 through December 2011 period.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2012 fuel and purchased power and capacity cost recovery projections?

A. Yes. There is a significant event reflected in the 2012 projections: stabilization of natural gas prices after several years of steady price declines and related hedge results.

Q. Please describe the results of this natural gas pricing event.

A. With the addition of Bayside Station in 2004 and more recently the combustion turbines ("CT's") at Polk, Bayside and Big Bend Stations, Tampa Electric increased its reliance on natural gas as a fuel source. The prolonged economic downturn resulted in a decline in fuel commodity prices, particularly natural gas, which translated into a significant decrease in fuel and purchased power costs over the period. However, more recently fuel commodity prices started to stabilize and in some cases increase compared to prior periods. To mitigate fuel price volatility and comply with the company's Commission-approved Risk Management Plan, financial hedges have been entered into for natural gas in 2011 and 2012. Tampa Electric witness J. Brent Caldwell's direct testimony describes existing and forecasted natural gas costs and associated hedge results in more detail.

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric's projected wholesale incentive benchmark for 2012?

A. The company's projected 2012 benchmark is $2,482,588, which is the three-year average of $3,533,488, $2,948,964 and $965,313 in gains on the company's non-separated wholesale sales, excluding emergency sales, for 2009, 2010 and 2011 (estimated/actual), respectively.

Q. Does Tampa Electric expect gains in 2012 from non-separated wholesale sales to exceed its 2012 wholesale incentive benchmark?

A. No. Tampa Electric anticipates that sales will not exceed the projected benchmark for 2012. Therefore, all sales margins will flow back to customers.

Cost Recovery Factors

Q. What is the composite effect of Tampa Electric's proposed changes in its capacity, fuel and purchased power, environmental and energy conservation cost recovery factors on a 1,000 kWh residential customer's bill?

A. The composite effect on a residential bill for 1,000 kWh is a decrease of $0.12 beginning January 2012. These charges are shown in Exhibit No. ____ (CA-3), Document No. 2, on Schedule E10.

Q. When should the new rates go into effect?

A. The new rates should go into effect concurrent with meter reads for the first billing cycle for January 2012.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

Q. Please state your name, address, occupation and employer.

A. My name is Carlos Aldazabal. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Director, Regulatory Affairs in the Regulatory Affairs Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science Degree in Accounting in 1991, and received a Masters of Accountancy from the University of South Florida in Tampa in 1995. I am a CPA in the State of Florida and have accumulated 16 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, and budgeting and analysis. In April 1999, I joined Tampa Electric as Supervisor, Regulatory Accounting. In January 2004, I became Manager Regulatory Affairs where my duties included managing cost recovery for fuel and purchased power, interchange sales, and capacity payments. In August 2009, I was promoted to Director Regulatory Affairs with primary responsibility for overseeing all of the cost recovery clauses.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2011 through December 2011 fuel and purchased power and capacity true-up amounts to be recovered in the January 2012 through December 2012 projection period. My testimony addresses the recovery of fuel and purchased power costs as well as capacity costs for the year 2011, based on six months of actual data and six months of estimated data. This information will be used in the determination of the 2012 fuel and purchased power costs and capacity cost recovery factors.

Q. Have you prepared any exhibits to support your testimony?

A. Yes. I have prepared Exhibit No. ____ (CA-2), which contains two documents. Document No. 1 is comprised of Schedules E1-B, E-2, E-3, E-4, E-5, E-6, E-7, E-8, and E-

9, which provide the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2011 through December 2011. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period of January 2011 through December 2011. These documents are furnished as support for the projected true-up amount for this period.

Fuel and Purchased Power Cost Recovery Factors

Q. What has Tampa Electric calculated as the estimated net true-up amount for the current period to be applied in the January 2012 through December 2012 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount applicable for the period January 2012 through December 2012 is an over-recovery of $47,813,410.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2012 through December 2012 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2012 is the sum of the final true-up amount for the period January 2010 through December 2010 and the actual/estimated true-up amount for the period January 2011 through December 2011.

Q. What did Tampa Electric calculate as the final fuel and purchased power cost recovery true-up amount for 2010?

A. The final true-up was an over-recovery of $5,086,991. The actual fuel cost over-recovery, including interest was $72,174,864 for the period January 2010 through December 2010. The $72,174,864 amount, less the actual/estimated over-recovery amount of $67,087,873 approved in Order No. PSC-10-0734-FOF-EI, issued December 20, 2010 in Docket No. 100001-EI resulted in a net over-recovery amount for the period of $5,086,991.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2011 through December 2011?

A. The actual/estimated fuel and purchased power cost recovery true-up is an over-recovery amount of $42,726,419 for the January 2011 through December 2011 period. The detailed calculation supporting the actual/estimated current period true-up is shown in Exhibit No. ____ (CA-2), Document No. 1 on Schedule E1-B.

Capacity Cost Recovery Clause

Q. What has Tampa Electric calculated as the estimated net true-up amount to be applied in the January 2012 through December 2012 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January 2012 through December 2012 is an under-recovery of $429,583 as shown in Exhibit No. ____ (CA-2), Document No. 2, page 2 of 5.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2012 through December 2012 capacity cost recovery factors?

A. The net true-up amount to be recovered in the 2012 capacity cost recovery factors is the sum of the final true-up amount for 2010 and the actual/estimated true-up amount for January 2011 through December 2011.

Q. What did Tampa Electric calculate as the final capacity cost recovery true-up amount for 2010?

A. The final 2010 true-up is an under-recovery of $461,060. The actual capacity cost under-recovery including interest was $514,151 for the period January 2010 through

December 2010. The $514,151 amount, less the actual/estimated under-recovery amount of $53,091 approved in Order No. PSC-10-0734-FOF-EI issued December 20, 2010 in Docket No. 100001-EI results in a net under-recovery amount for the period of $461,060 as identified in Exhibit No. ____ (CA-2), Document No. 2, page 1 of 5.

Q. What did Tampa Electric calculate as the actual/estimated capacity cost recovery true-up amount for the period January 2011 through December 2011?

A. The actual/estimated true-up amount is an over-recovery of $31,477 as shown on Exhibit No. ____ (CA-2), Document No. 2, page 1 of 5.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 110001-EI
FILED: 03/15/2011

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

Q. Please state your name, business address, occupation and employer.

A. My name is Brian S. Buckley. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Operations Planning.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Mechanical Engineering in 1997 from the Georgia Institute of Technology and a Master of Business Administration from the University of South Florida in 2003. I began my career with Tampa Electric in 1999 as an Engineer in Plant Technical Services. I have held a number of different engineering positions at Tampa Electric's power generating stations including Operations Engineer at Gannon Station, Instrumentation and Controls Engineer at Big Bend Station, and Senior Engineer in Operations Planning. In August 2008, I was promoted to Manager, Operations Planning, where I am currently responsible for unit commitment, unit performance analysis and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Tampa Electric's actual performance results from unit equivalent availability and station heat rate used to determine the Generating Performance Incentive Factor ("GPIF") for the period January 2010 through December 2010. I will also compare these results to the targets established prior to the beginning of the period.

Q. Have you prepared an exhibit to support your testimony?

A. Yes, I prepared Exhibit No. _____ (BSB-1), consisting of two documents. Document No. 1, entitled "Tampa Electric Company, Generating Performance Incentive Factor, January 2010 - December 2010 True-up" is consistent with the GPIF Implementation Manual previously approved by the Commission. Document No. 2 provides the company's Actual Unit Performance Data for the 2010 period.

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Four of the company's coal-fired units, one integrated gasification combined cycle unit and two natural gas combined cycle units are included. These are Big Bend Units 1 through 4, Polk Unit 1 and Bayside Units 1 and 2, respectively.

Q. Have you calculated the results of Tampa Electric's performance under the GPIF during the January 2010 through December 2010 period?

A. Yes, I have. This is calculated in Document No. 1, page 4 of 32. Based upon 2.722 Generating Performance Incentive Points ("GPIP"), the result is a reward amount of $2,054,696 for the period.

Q. Please proceed with your review of the actual results for the January 2010 through December 2010 period.

A. In Document No. 1, page 3 of 32, the actual average common equity for the period is shown on line 14 as $1,875,266,538. This produces the maximum penalty or reward amount of $7,547,230 as shown on line 21.

Q. Will you please explain how you arrived at the actual equivalent availability results for the seven units included within the GPIF?

A. Yes. Operating data for each of the units is filed monthly with the Commission on the Actual Unit Performance Data form. Additionally, outage information is reported to the Commission on a monthly basis. A summary of this data for the 12 months provides the basis for the GPIF.

Q. Are the actual equivalent availability results shown on Document No. 1, page 6 of 32, directly applicable to the GPIF table?

A. No. Adjustments to actual equivalent availability may be required as noted in section 4.3.3 of the GPIF Manual. The actual equivalent availability including the required adjustment is shown in Document No. 1, page 6 of 32. The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the Commission's Staff. The adjustments for each unit are as follows:

Big Bend Unit No. 1

On this unit, 2351.0 planned outage hours were originally scheduled for 2010. Actual outage activities required 2143.4 planned outage hours. Consequently, the actual equivalent availability of 60.5 percent is adjusted to 58.6 percent as shown on Document No. 1, page 7 of 32.

Big Bend Unit No. 2

On this unit, 384.0 planned outage hours were originally scheduled for 2010. Actual outage activities required 479.5 planned outage hours. Consequently, the actual equivalent availability of 68.4 percent is adjusted to 69.2 percent as shown on Document No. 1, page 8 of 32.

Big Bend Unit No. 3

On this unit, 744.0 planned outage hours were originally scheduled for 2010. Actual outage activities required 732.3 planned outage hours. Consequently, the actual equivalent availability of 79.8 percent is adjusted to 79.7 percent as shown on Document No. 1, page 9 of 32.

Big Bend Unit No. 4

On this unit, 1344.0 planned outage hours were originally scheduled for 2010. Actual outage activities required 1693.2 planned outage hours. Consequently, the actual equivalent availability of 66.5 percent is adjusted to 69.8 percent as shown on Document No. 1, page 10 of 32.

Polk Unit No. 1

On this unit, 336.0 planned outage hours were originally scheduled for 2010. Actual outage activities required 419.2 planned outage hours. Consequently, the actual equivalent availability of 90.0 percent is adjusted to 91.0 percent, as shown on Document No. 1, page 11 of 32.

Bayside Unit No. 1

On this unit, 336.0 planned outage hours were originally scheduled for 2010. Actual outage activities required 439.1 planned outage hours. Consequently, the actual equivalent availability of 93.9 percent is adjusted to 95.1 percent, as shown on Document No. 1, page 12 of 32.

Bayside Unit No. 2

On this unit, 336.0 planned outage hours were originally scheduled for 2010. Actual outage activities required 760.7 planned outage hours. Consequently, the actual equivalent availability of 89.5 percent is adjusted to 94.3 percent, as shown on Document No. 1, page 13 of 32.

Q. How did you arrive at the applicable equivalent availability points for each unit?

A. The final adjusted equivalent availabilities for each unit are shown on Document No. 1, page 6 of 32. This number is entered into the respective GPIP table for each particular unit, shown on pages 7 of 32 through 13 of 32. Page 4 of 32 summarizes the weighted equivalent availability points to be awarded or penalized.

Q. Will you please explain the heat rate results relative to the GPIF?

A. The actual heat rate and adjusted actual heat rate for Tampa Electric's seven GPIF units are shown on Document No. 1, page 6 of 32. The adjustment was developed based on the guidelines of section 4.3.16 of the GPIF Manual. This procedure is further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the FPSC Staff. The final adjusted actual heat rates are also shown on page 5 of 32. The heat rate value is entered into the respective GPIP table for the particular unit, shown on pages 14 through 20 of 32. Page 4 of 32 summarizes the weighted heat rate points to be awarded or penalized.

Q. What is the overall GPIP for Tampa Electric for the January 2010 through December 2010 period?

A. This is shown on Document No. 1, page 2 of 32. Essentially, the weighting factors shown on page 4 of 32, plus the equivalent availability points and the heat rate points shown on page 4 of 32, are substituted within the equation found on page 32 of 32. The resulting value, 2.722, is then entered into the GPIF table on page 2 of 32. Using linear interpolation, the reward amount is $2,054,696.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 110001-EI
FILED: 9/1/2010
REVISED: 4/11/2011

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

Q. Please state your name, business address, occupation and employer.

A. My name is Brian S. Buckley. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Operations Planning.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Mechanical Engineering in 1997 from the Georgia Institute of Technology and a Master of Business Administration from the University of South Florida in 2003. I began my career with Tampa Electric in 1999 as an Engineer in Plant Technical Services. I have held a number of different engineering positions at Tampa Electric's power generating stations including operations, instrumentation and controls, performance planning and asset management. In October 2008, I was promoted to Manager, Operations Planning, where I am currently responsible for unit commitment and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. My testimony describes Tampa Electric's maintenance planning processes and presents Tampa Electric's methodology for determining the various factors required to compute the Generating Performance Incentive Factor ("GPIF") as ordered by the Commission.

Q. Have you prepared any exhibits to support your testimony?

A. Yes, Exhibit No. ____ (BSB-2), consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2011 period.

Q. Which generating units on Tampa Electric's system are included in the determination of the GPIF?

A. Four of the company's coal-fired units, one integrated gasification combined cycle unit and two natural gas combined cycle units are included. These are Big Bend Units 1 through 4, Polk Unit 1 and Bayside Units 1 and 2.

Q. Do the exhibits you prepared comply with Commission-approved GPIF methodology?

A. Yes, the documents are consistent with the GPIF Implementation Manual previously approved by the Commission. To account for the concerns presented in the testimony of Commission Staff witness Sidney W. Matlock during the 2005 fuel hearing, Tampa Electric removes outliers from the calculation of the GPIF targets. Section 3.3 of the GPIF Implementation Manual allows for removal of outliers, and the methodology was approved by the Commission in Order No. PSC-06-1057-FOF-EI issued in Docket No. 060001-EI on December 22, 2006.

Q. Did Tampa Electric identify any outages as outliers?

A. Yes. One outage from Big Bend Unit 1, one outage from Big Bend Unit 2, one outage from Big Bend Unit 3 and one outage from Polk Unit 1 were identified as outlying outages; therefore, the associated forced outage hours were removed from the study.

Q. Please describe how Tampa Electric developed the various factors associated with the GPIF.

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2011 period. A range of potential improvements and degradations were determined for each of these metrics.

Q. How were the target values for unit availability determined?

A. The Planned Outage Factor ("POF") and the Equivalent Unplanned Outage Factor ("EUOF") were subtracted from 100 percent to determine the target Equivalent Availability Factor ("EAF"). The factors for each of the seven units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2011 period, the projected EUOF for Big Bend Unit 3 is 9.9 percent, and the POF is 6.6 percent. Therefore, the target EAF for Big Bend Unit 3 equals 83.5 percent or:

$$100\% - (9.9\% + 6.6\%) = 83.5\%$$

This is shown on page 4, column 3 of Document No. 1.

Q. How was the potential for unit availability improvement determined?

A. Maximum equivalent availability is derived by using the following formula:

$$EAF_{MAX} = 1 - [0.8 \ (EUOF_T) + 0.95 \ (POF_T)]$$

The factors included in the above equations are the same factors that determine the target equivalent availability. To determine the maximum incentive points, a 20 percent reduction in EUOF and Equivalent Maintenance Outage Factor ("EMOF"), plus a five percent reduction in the POF are necessary. Continuing with the Big Bend Unit 3 example:

$$EAF_{MAX} = 1 - [0.8 \ (9.9\%) + 0.95 \ (6.6\%)] = 85.8\%$$

This is shown on page 4, column 4 of Document No. 1.

Q. How was the potential for unit availability degradation determined?

A. The potential for unit availability degradation is significantly greater than the potential for unit availability improvement. This concept was discussed extensively during the development of the incentive. To incorporate this biased effect into the unit availability tables, Tampa Electric uses a potential degradation range equal to twice the potential improvement. Consequently, minimum equivalent availability is calculated using the following formula:

$$EAF_{MIN} = 1 - [1.40 \ (EUOF_T) + 1.10 \ (POF_T)]$$

Again, continuing with the Big Bend Unit 3 example,

$$EAF_{MIN} = 1 - [1.40 \ (9.9\%) + 1.10 \ (6.6\%)] = 78.9\%$$

The equivalent availability maximum and minimum for the other six units are computed in a similar manner.

Q. How did Tampa Electric determine the Planned Outage, Maintenance Outage, and Forced Outage Factors?

A. The company's planned outages for January through December 2011 are shown on page 21 of Document No. 1. Two GPIF units have a major outage of 28 days or greater in 2011; therefore, two Critical Path Method diagrams are provided. Planned Outage Factors are calculated for each unit. For example, Big Bend Unit 2 is scheduled for a planned outage from February 20, 2011 to March 1, 2011 and September 3, 2011 to November 18, 2011. There are 2,089 planned outage hours scheduled for the 2011 period, and a total of 8,760 hours during this 12-month period. Consequently, the POF for Big Bend Unit 2 is 23.8 percent or:

$$\frac{2,089}{8,760} \times 100\% = 23.8\%$$

The factor for each unit is shown on pages 5 and 14 through 20 of Document No. 1. Big Bend Unit 1 has a POF of 5.8 percent. Big Bend Unit 2 has a POF of 23.8 percent. Big Bend Unit 3 has a POF of 6.6 percent. Big Bend Unit 4 has a POF of 6.6 percent. Polk Unit 1 has a POF of 6.0 percent. Bayside Unit 1 has a POF of 21.1 percent, and Bayside Unit 2 has a POF of 3.8 percent.

Q. How did you determine the Forced Outage and Maintenance Outage Factors for each unit?

A. For each unit the most current 12-month ending value, June 2011, was used as a basis for the projection. All projected factors are based upon historical unit performance unless adjusted for outlying forced outages. These target factors are additive and result in a EUOF of 9.9 percent for Big Bend Unit 3. The EUOF for Big Bend Unit 3 is verified by the data shown on page 16, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

$$EUOF = \frac{(EFOH + EMOH)}{PH} \times 100\%$$

Or

$$EUOF = \frac{(722 + 142)}{8,760} \times 100\% = 9.9\%$$

Relative to Big Bend Unit 3, the EUOF of 9.9 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Big Bend Unit 1

The projected EUOF for this unit is 26.3 percent. The unit will have a planned outage in 2011, and the POF is 5.8 percent. Therefore, the target equivalent availability for this unit is 67.9 percent.

Big Bend Unit 2

The projected EUOF for this unit is 13.8 percent. The unit will have a planned outage in 2011, and the POF is 23.8 percent. Therefore, the target equivalent availability for this unit is 62.4 percent.

Big Bend Unit 3

The projected EUOF for this unit is 9.9 percent. The unit will have a planned outage in 2011, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 83.5 percent.

Big Bend Unit 4

The projected EUOF for this unit is 15.5 percent. The unit will have a planned outage in 2011, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 77.9 percent.

Polk Unit 1

The projected EUOF for this unit is 5.3 percent. The unit will have a planned outage in 2011, and the POF is 6.0 percent. Therefore, the target equivalent availability for this unit is 88.6 percent.

Bayside Unit 1

The projected EUOF for this unit is 0.7 percent. The unit will have a planned outage in 2011, and the POF is 21.1 percent. Therefore, the target equivalent availability for this unit is 78.2 percent.

Bayside Unit 2

The projected EUOF for this unit is 1.8 percent. The unit will have a planned outage in 2011, and the POF is 3.8 percent. Therefore, the target equivalent availability for this unit is 94.4 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 74.5 percent is shown on Page 5 of Document No. 1. This target is greater than the 2007, 2008 and 2009 January through December actual performances.

Q. Why are Forced and Maintenance Outage Factors adjusted for planned outage hours?

A. The adjustment makes the factors more accurate and comparable. A unit in a planned outage stage or reserve shutdown stage will not incur a forced or maintenance outage. To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor for Big Bend Unit 3 on page 16 of Document No. 1. Except for the months of March, April, October and November, the Equivalent Unplanned Outage Rate and the EUOF are equal. This is because no planned outages are scheduled during these months. During the months of March, April, October and November, the Equivalent Unplanned Outage Rate exceeds the EUOF due to scheduled planned outages. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

Q. Does this mean that both rate and factor data are used in calculated data?

A. Yes. Rates provide a proper and accurate method of determining the unit metrics, which are subsequently converted to factors. Therefore,

$$EFOF + EMOF + POF + EAF = 100\%$$

Since factors are additive, they are easier to work with and to understand.

Q. Has Tampa Electric prepared the necessary heat rate data required for the determination of the GPIF?

A. Yes. Target heat rates and ranges of potential operation have been developed as required and have been adjusted to reflect the aforementioned agreed upon GPIF methodology.

Q. How were these targets determined?

A. Net heat rate data for the three most recent July through June annual periods formed the basis of the target development. The historical data and the target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or equipment modifications having material effect on heat rate can be taken into consideration.

Q. How were the ranges of heat rate improvement and heat rate degradation determined?

A. The ranges were determined through analysis of historical net heat rate and net output factor data. This is the same data from which the net heat rate versus net output factor curves have been developed for each unit. This information is shown on pages 31 through 37 of Document No. 1.

Q. Please elaborate on the analysis used in the determination of the ranges.

A. The net heat rate versus net output factor curves are the result of a first order curve fit to historical data. The standard error of the estimate of this data was determined, and a factor was applied to produce a band of potential improvement and degradation. Both the curve fit and the standard error of the estimate were performed by computer program for each unit. These curves are also used in post-period adjustments to actual heat rates to account for unanticipated changes in unit dispatch.

Q. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2011 period.

A. The heat rate target for Big Bend Unit 1 is 10,649 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±474 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,379 Btu/Net kWh with a range of ±354 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,602 Btu/Net kWh, with a range of ±337 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,599 Btu/Net kWh with a range of ±312 Btu/Net kWh. The heat rate target for Polk Unit 1 is 9,820 Btu/Net kWh with a range of ±703 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,212 Btu/Net kWh with a range of ±93 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,311 Btu/Net kWh with a range of ±89 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within the range for each target. This is shown on page 4, and pages 7 through 13 of Document No. 1.

Q. Do the heat rate targets and ranges in Tampa Electric's projection meet the criteria of the GPIF and the philosophy of the Commission?

A. Yes.

Q. After determining the target values and ranges for average net operating heat rate and equivalent availability, what is the next step in the GPIF?

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown on pages 7 through 13. The baseline production costing analysis was performed to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $872,944,300 is shown on page 6, column 2. Multiple production cost simulations were performed to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6, column 4 of Document No. 1.

After all of the individual savings are calculated, column 4 totals $28,353,900 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing individual savings by the total. For Big Bend Unit 3, the weighting factor for equivalent availability is 6.47 percent as shown in the right-hand column on page 6. Pages 7 through 13 of Document No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, on Big Bend Unit 3, page 9, if the unit operates at 85.8 percent equivalent availability, fuel savings would equal $1,833,900, and 10 equivalent availability points would be awarded.

The GPIF Reward/Penalty table on page 2 is a summary of the tables on pages 7 through 13. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, or $28,353,900. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How was the maximum allowed incentive determined?

A. Referring to page 3, line 14, the estimated average common equity for the period January through December 2011 is $1,902,870,049. This produces the maximum allowed jurisdictional incentive of $7,711,175 shown on line 21.

Q. Are there any other constraints set forth by the Commission regarding the magnitude of incentive dollars?

A. Yes. Incentive dollars are not to exceed 50 percent of fuel savings. Page 2 of Document No. 1 demonstrates that this constraint is met.

Q. Please summarize your testimony.

A. Tampa Electric has complied with the Commission's directions, philosophy, and methodology in its determination of the GPIF. The GPIF is determined by the following formula for calculating Generating Performance Incentive Points (GPIP):

$$
\begin{aligned}
GPIP: = (\ & 0.0479\ EAP_{BB1} + 0.0623\ EAP_{BB2} \\
& + 0.0647\ EAP_{BB3} + 0.0825\ EAP_{BB4} \\
& + 0.0070\ EAP_{PK1} + 0.0140\ EAP_{BAY1} \\
& + 0.0033\ EAP_{BAY2} + 0.1309\ HRP_{BB1} \\
& + 0.0871\ HRP_{BB2} + 0.1013\ HRP_{BB3} \\
& + 0.1062\ HRP_{BB4} + 0.1631\ HRP_{PK1} \\
& + 0.0515\ HRP_{BAY1} + 0.0782\ HRP_{BAY2})
\end{aligned}
$$

Where:

GPIP = Generating Performance Incentive Points.

EAP = Equivalent Availability Points awarded/deducted for Big Bend Units 1, 2, 3, and 4, Polk Unit 1 and Bayside Units 1 and 2.

HRP = Average Net Heat Rate Points awarded/deducted for Big Bend Units 1, 2, 3, and 4, Polk Unit 1 and Bayside Units 1 and 2.

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2011 period?

A. Yes. Document No. 2 entitled "Summary of GPIF Targets" provides the availability and heat rate targets for each unit.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH II

Q. Please state your name, address, occupation and employer.

A. My name is Benjamin F. Smith II. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the Wholesale Marketing group within the Fuels Management Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Science degree in Electric Engineering in 1991 from the University of South Florida in Tampa, Florida and am a registered Professional Engineer within the State of Florida. I joined Tampa Electric in 1990 as a cooperative education student. During my years with the company, I have worked in the areas of transmission engineering, distribution engineering, resource planning, retail marketing, and wholesale power marketing. I am currently the Manager of

Energy Products and Structures in the Wholesale Marketing group. My responsibilities are to evaluate short and long-term purchase and sale opportunities within the wholesale power market, assist in wholesale contract structure and help evaluate the processes used to value wholesale power opportunities. In this capacity, I interact with wholesale power market participants such as utilities, municipalities, electric cooperatives, power marketers and other wholesale generators.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I have submitted written testimony in the annual fuel docket since 2003, and I testified before this Commission in Docket Nos. 030001-EI, 040001-EI, and 080001-EI regarding the appropriateness and prudence of Tampa Electric's wholesale purchases and sales.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my testimony is to provide a description of Tampa Electric's purchased power agreements that the company has entered into and for which it is seeking cost recovery through the Fuel and Purchased Power Cost Recovery Clause ("fuel clause") and the Capacity Cost Recovery Clause. I also describe Tampa Electric's purchased power strategy for mitigating price and supply-side risk, while providing customers with a reliable supply of economically priced purchased power.

Q. Please describe the efforts Tampa Electric makes to ensure that its wholesale purchases and sales activities are conducted in a reasonable and prudent manner.

A. Tampa Electric evaluates potential purchased power needs and sale opportunities by analyzing the expected available amounts of generation and the power required to meet the projected demand and energy of its customers. Purchases are made to achieve reserve margin requirements, meet customers' demand and energy needs, supplement generation during unit outages, and for economical purposes. When there is a purchased power need, the company aggressively polls the marketplace for wholesale capacity or energy, searching for reliable supplies at the best possible price from creditworthy counterparties.

Conversely, when there is a sales opportunity, the company offers profitable wholesale capacity or energy products to creditworthy counterparties. The company has wholesale power purchase and sale transaction enabling agreements with numerous counterparties. This process helps to ensure that the company's wholesale purchase and sale activities are conducted in a reasonable and prudent manner.

Q. Has Tampa Electric reasonably managed its wholesale power purchases and sales for the benefit of its retail customers?

A. Yes, it has. Tampa Electric has fully complied with, and continues to fully comply with, the Commission's March 11, 1997 Order, No. PSC-97-0262-FOF-EI, issued in Docket No. 970001-EI, which governs the treatment of separated and non-separated wholesale sales. The company's wholesale purchase and sale activities and transactions are also reviewed and audited on a recurring basis by the Commission.

In addition, Tampa Electric actively manages its wholesale purchases and sales with the goal of capitalizing on opportunities to reduce customer costs. The company monitors its contractual rights with purchased power suppliers as well as with entities to which wholesale power is sold to detect and prevent any breach of the company's contractual rights. Also, Tampa Electric continually strives to improve its knowledge of wholesale power markets and the available opportunities within the marketplace. The company uses this knowledge to minimize the costs of purchased power and to maximize the savings the company provides retail customers by making wholesale sales when excess power is available on Tampa Electric's system and market conditions allow.

Q. Please describe Tampa Electric's 2011 wholesale energy purchases.

A. Tampa Electric assessed the wholesale power market and entered into short and long-term purchases based on price and availability of supply. Approximately 7 percent of the expected energy needs for 2011 will be met using purchased power. This purchased power energy includes economy purchases and existing firm purchased power agreements with Hardee Power Partners, Calpine, RRI Energy Services (formally known as Reliant), Pasco Cogen, and qualifying facilities. The testimony in previous years describes each existing firm purchased power agreement, which were subsequently approved by the

Commission as being cost-effective for Tampa Electric customers. All of the aforementioned purchases provide supply reliability and help reduce fuel price volatility.

Q. Has Tampa Electric entered into any other wholesale energy purchases for 2011?

A. Yes. The term of the original 170 MW Calpine purchase was May 2006 through April 2011. Tampa Electric extended the contract for 117 MW through September 2011 to support Tampa Electric's system during a major unit planned outage. The Calpine extension capacity pricing is 65 percent less than the original contract. This reduced capacity price, along with fuel benefits, results in a small forecasted savings to customers. Additionally, the Calpine extension has already provided coverage for unplanned unit outages and additional purchased power price protection throughout the summer.

Also, in May 2011, Tampa Electric issued a solicitation for proposals (i.e., request to purchase power) to the marketplace. The purpose of the solicitation was to evaluate firm power purchase options capable of filling the company's 2013-2015 reserve margin needs, as shown in its 2011 Ten Year Site Plan. Currently, the company is in discussions with the short listed bidders to determine if a purchase (or combination of purchases) is in the best interest for Tampa Electric customers. In addition to the solicitation, Tampa Electric will continue to evaluate economic combinations of forward and spot market energy purchases during its spring and fall generation maintenance periods and peak periods. This purchasing strategy provides a reasonable and diversified approach to serving customers.

Q. Has Tampa Electric entered into any other wholesale energy purchases for 2012 and beyond?

A. In 2012, the Tampa Electric expects purchased power to meet approximately 5 percent of its energy needs. Excluding the discussions with short listed bidders from the previously described May 2011 solicitation for proposals which could result in a cost-effective purchase, the company has no additional plans to purchase long-term capacity and energy at this time. Tampa Electric, however, will continue to evaluate the short-term purchased power market as part of its purchasing strategy.

Q. Does Tampa Electric engage in physical or financial hedging of its wholesale energy transactions to mitigate wholesale energy price volatility?

A. Physical and financial hedges can provide measurable market price volatility protection. Tampa Electric purchases physical wholesale power products. The company has not engaged in financial hedging for wholesale transactions because the availability of financial instruments within the Florida market is limited. The Florida wholesale power market currently operates through bilateral contracts between various counterparties, and there is not a Florida trading hub where standard financial transactions can occur with enough volume to create a liquid market. Due to this lack of liquidity, the appropriate financial instruments to meet the company's needs do not currently exist. Tampa Electric has not purchased any wholesale energy derivatives; however, the company employs a diversified power supply strategy, which includes self-generation, short and long-term capacity and energy purchases. This strategy provides the company the opportunity to take advantage of favorable spot market pricing while maintaining reliable service to its customers.

Q. Does Tampa Electric's risk management strategy for power transactions adequately mitigate price risk for purchased power for 2011?

A. Yes, Tampa Electric expects its physical wholesale purchases to continue to reduce its customers' purchased power price risk. For example, the 170 MW (and subsequent 117 MW) Calpine purchase and the 158 MW purchase from RRI Energy Services in 2011 are reliable, cost-based call options for peaking power. These purchases serve as both a physical hedge and reliable source of economic power in 2011. The availability of these purchases is high, and their price structures provide some protection from rising market prices, which are largely influenced by supply and the volatility of natural gas prices.

Mitigating price risk is a dynamic process, and Tampa Electric continually evaluates its options in light of changing circumstances and new opportunities. Tampa Electric also strives to maintain an optimum level and mix of short- and long-term capacity and energy purchases to augment the company's own generation for the year 2011 and beyond.

Q. How does Tampa Electric mitigate the risk of disruptions to its purchased power supplies during major weather related events such as hurricanes?

A. During hurricane season, Tampa Electric continues to utilize a purchased power risk management strategy to minimize potential power supply disruptions during major weather related events. The strategy includes monitoring storm activity; evaluating the impact of storms on the wholesale power market; purchasing power on the forward market for reliability and economics; evaluating transmission availability and the geographic location of electric resources; reviewing the seller's fuel sources and dual-fuel capabilities; and focusing on fuel-diversified purchases. Notably, both the RRI Energy Services and Pasco Cogen purchases are dual-fuel resources. This allows these resources to run on either natural gas or oil, which enhances supply reliability during a potential hurricane-related disruption in natural gas supply. Absent the threat of a hurricane, and for all other months of the year, the company continues its strategy of evaluating economic combinations of short- and long-term purchase opportunities identified in the marketplace.

Q. Please describe Tampa Electric's wholesale energy sales for 2011 and 2012.

A. Tampa Electric entered into various non-separated wholesale sales in 2011, and the company anticipates making additional non-separated sales during the balance of 2011 and in 2012. In accordance with Order No. PSC-01-2371-FOF-EI, issued on December 7, 2001 in Docket No. 010283-EI, all gains from non-separated sales are returned to customers through the fuel clause, up to the three-year rolling average threshold. For all gains above the three-year rolling average threshold, customers receive 80 percent and the company retains the remaining 20 percent. In 2011, Tampa Electric anticipates its gains from non-separated wholesale sales to be $965,313 of which 100 percent would flow back to customers since they are less than the three-year rolling average threshold of $2,719,531. Similarly, in 2012, the company's projected gains from non-separated wholesale sales are $737,492 of which 100 percent would flow back to customers since they are less than the projected 2012 three-year rolling average threshold of $2,160,817.

Q. Please summarize your testimony.

A. Tampa Electric monitors and assesses the wholesale power market to identify and take advantage of opportunities in the marketplace, and these efforts benefit the company's customers. Tampa Electric's energy supply strategy includes self-generation and short- and long-term power purchases. The company purchases in both the physical forward and spot wholesale power markets to provide customers with a reliable supply at the lowest possible cost. It also enters into wholesale sales that benefit customers. Tampa Electric does not purchase wholesale energy derivatives in the Florida wholesale power market due to a lack of financial instruments appropriate for the company's operations. It does, however, employ a diversified power supply strategy to mitigate price and supply risks.

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 110001-EI
FILED: 04/01/2011

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRENT CALDWELL

Q. Please state your name, address, occupation and employer.

A. My name is Brent Caldwell. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Origination & Market Services.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor Degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science in Electrical Engineering in 1988. I have over 15 years of utility experience with an emphasis in state and federal regulatory matters, natural gas procurement and transportation, fuel logistics and cost reporting, and business systems and analysis. In October 2010 I assumed the long-term fuel origination responsibilities of Joann Wehle who was the previous witness in the fuel docket.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present, for the Florida Public Service Commission's ("FPSC" or "Commission") review, information regarding the 2010 results of Tampa Electric's risk management activities, as required by the terms of the stipulation entered into by the parties to Docket No. 011605-EI and approved by the Commission in Order No. PSC-02-1484-FOF-EI.

Q. Do you wish to sponsor an exhibit in support of your testimony?

A. Yes. Exhibit No. ___ (BC-1), entitled Tampa Electric Company's 2010 Fuel Procurement Risk Management Report, was prepared under my direction and supervision. This report explains the company's risk management activities and results for the calendar year 2010.

Q. What is the source of the data you present in your testimony in this proceeding?

A. Unless otherwise indicated, the source of the data is the books and records of Tampa Electric. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by this Commission.

Q. What were the results of Tampa Electric's risk management activities in 2010?

A. As outlined in Tampa Electric's 2010 Fuel Procurement Risk Management Plan, filed concurrently with this testimony on April 1, 2011 in Docket No. 110001-EI, the company follows a non-speculative risk management strategy to reduce fuel price volatility while maintaining a reliable supply of fuel. In particular, Tampa Electric established a financial hedging program to limit its exposure to spikes in the price of natural gas. Over time, this program has been enhanced as Tampa Electric's gas needs have evolved and grown. All enhancements have been reviewed and approved by the company's Risk Authorization Committee.

The report indicates that Tampa Electric's 2010 hedging activities resulted in a net loss of approximately $68 million. Tampa Electric followed the plan objective of reducing price volatility while maintaining a reliable fuel supply. A decrease in natural gas prices began in the middle of 2008 due to lower demand as a result of the recession as well as from increased supply from non-conventional, shale gas, production. Natural gas prices continue to stay at a low price due to this supply surplus.

Q. Does Tampa Electric implement physical hedges for natural gas?

A. Yes. In addition to financial hedging, Tampa Electric uses physical hedging for natural gas. Using a variety of sources such as delivery methods, inventory locations and contractual terms enhances the company's supply reliability and flexibility to cost-effectively meet changing operational needs.

Tampa Electric continually pursues new creditworthy counterparties and maintains contracts for gas supplies from various regions and on different pipelines. The company also contracts for pipeline capacity to access non-conventional shale gas production which is less sensitive to interruption by hurricanes. Tampa Electric also has storage capacity with Bay Gas Storage near

Mobile, Alabama. All of these actions enhance the effectiveness of Tampa Electric's gas supply portfolio.

Q. Does Tampa Electric use a hedging information system?

A. Yes, Tampa Electric continues to use Sungard's Nucleus Risk Management System ("Nucleus"). Nucleus supports sound hedging practices with its contract management, separation of duties, credit tracking, transaction limits, deal confirmation and business report generation functions. The Nucleus system records all financial natural gas hedging transactions, and the system calculates risk management reports. Nucleus is also used for contract, credit management and risk exposure analysis.

Q. What were the results of the company's incremental hedging activities in 2010?

A. The net result of natural gas hedging activity in 2010 was a loss of approximately $68 million when the instrument prices were compared to market prices on settled positions.

Q. Did the company use financial hedges for other commodities in 2010?

A. No. Tampa Electric did not use financial hedges for other commodities.

Tampa Electric's generation is comprised mostly of coal and natural gas. Although the price of coal has increased, it is relatively stable compared to the prices of oil and natural gas. In addition, there is not an organized and liquid market for financial hedging instruments for the high sulfur Illinois Basin coal that Tampa Electric uses at Big Bend Station, its largest coal-fired generation facility.

Tampa Electric consumes a small amount of oil, however, its low and erratic usage pattern makes price hedging impractical.

The company did not use financial hedges for wholesale energy transactions because a liquid, published market does not exist for power in Florida.

Q. Did Tampa Electric use physical hedges for other commodities?

A. Yes, Tampa Electric used physical hedges to enhance the reliability of its coal and oil supply.

For coal, the company entered into a portfolio of contracts with differing terms and various suppliers to obtain the types of coal used on its system. Additionally in 2010, Tampa Electric added rail delivery capability for coal to Big Bend Station. The addition of rail to the already existing waterborne transportation enhances Tampa Electric's access to coal supply and increases the reliability.

For oil, Tampa Electric fills its oil tanks prior to entering hurricane season to reduce exposure to supply or price issues that may arise during hurricane season.

Q. What is the basis for your request to recover the commodity and transaction costs described above?

A. Tampa Electric requests cost recovery pursuant to the Commission Order No. PSC-02-1484-FOF-EI, in Docket No. 011605-EI that states:

> "Each investor-owned electric utility shall be authorized to charge/credit to the fuel and purchased power cost recovery clause its non-speculative, prudently-incurred commodity costs and gains and losses associated with financial and/or physical hedging transactions for natural gas,

residual oil, and purchased power contracts tied to the price of natural gas."

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

Q. Please state your name, business address, occupation and employer.

A. My name is J. Brent Caldwell. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Origination & Market Services.

Q. Are you the same J. Brent Caldwell who previously filed direct testimony on behalf of Tampa Electric Company in this docket?

A. Yes, I am.

Q. What is the purpose of your current testimony?

A. The purpose of my testimony is to sponsor and describe my Exhibit No. (JBC-3), entitled Tampa Electric Natural Gas Risk Management Activities, January - July 2011.

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes, it was.

Q. Please describe this exhibit.

A. My Exhibit __ (JBC-3) shows details of Tampa Electric's hedging activities for natural gas for the seven month period January through July 2011.

Q. Does his conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

Q. Please state your name, business address, occupation and employer.

A. My name is J. Brent Caldwell. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Origination & Market Services.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor Degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science in Electrical Engineering from University of South Florida in 1988. I have over 15 years of utility experience with an emphasis in state and federal regulatory matters, natural gas procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October 2010, I assumed the long-term fuel origination responsibilities of Joann Wehle who was the previous witness in the fuel docket.

Q. Are you the same J. Brent Caldwell who previously filed direct testimony on behalf of Tampa Electric Company in this docket?

A. Yes, I am.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor and describe Exhibit No. ____ (JBC-2), entitled Tampa Electric Company's Fuel Procurement and Wholesale Power Purchases Risk Management Plan 2012.

Q. Was this exhibit prepared by you or under your direction and supervision?

A. Yes, it was.

Q. Please describe this exhibit.

A. My exhibit, No. ____ (JBC-2) sets forth all of the various details of Tampa Electric's overall plan for mitigating risk in the company's procurement of generation fuel and purchased power during 2012.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

Q. Please state your name, address, occupation and employer.

A. My name is J. Brent Caldwell. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director of Origination & Market Services.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor Degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science in Electrical Engineering in 1988. I have over 15 years of utility experience with an emphasis in state and federal regulatory matters, natural gas procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October 2010, I assumed the long-term fuel origination responsibilities of Joann Wehle who was the previous witness in the fuel docket.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to discuss Tampa Electric's fuel mix, fuel price forecasts, potential impacts to fuel prices, and the company's fuel procurement strategies. I will address steps Tampa Electric takes to manage fuel supply reliability and price volatility and describe projected hedging activities. I also sponsor Tampa Electric's 2012 Risk Management Plan and Hedging Report submitted on August 1, and August 15, 2011 in this docket.

Q. Have you previously submitted testimony to this Commission?

A. Yes. I have filed testimony before this Commission in this docket on April 1, 2011, August 1, 2011 and August 15, 2011.

2012 Fuel Mix and Procurement Strategies

Q. What fuels will Tampa Electric's generating stations use in 2012?

A. In 2012, coal-fired generation is expected to be approximately 60 percent and natural-gas fired generation

40 percent of total generation. Generation from oil is expected to be less than one percent of the total expected generation.

Q. Please describe Tampa Electric's fuel supply procurement strategy.

A. Tampa Electric emphasizes flexibility and options in its fuel procurement strategy for all of its fuel needs. The company strives to maintain a large number of creditworthy and viable suppliers. Tampa Electric also attempts to diversify the location from which its supply is sourced. Similarly, the company attempts to maintain multiple delivery paths wherever possible. Tampa Electric believes that increasing the number of fuel supply options provides increased reliability and lower costs for customers.

Coal Supply Strategy

Q. Please describe Tampa Electric's coal usage and procurement strategy.

A. Tampa Electric uses coal as the sole fuel for the four pulverized-coal steam turbine units at Big Bend Station and as the primary fuel for the integrated-gasification combine cycle Unit One at Polk Station. The coal-fired units at Big Bend Station are all fully scrubbed for sulfur-dioxide and nitrogen-oxides and are designed to burn high-sulfur Illinois Basin coal. Polk Unit One currently burns a mix of petroleum coke and low sulfur coal. Each plant has varying operational and environmental restrictions and requires fuel with custom quality characteristics such as ash content, fusion temperature, sulfur content, heat content and chlorine content. Since coal is not a homogenous product, fuel selection is based on these unique characteristics, price, availability, deliverability and creditworthiness of the supplier.

To minimize cost, maintain operational flexibility, and ensure reliable supply, Tampa Electric maintains a portfolio of bilateral coal supply contracts with varying term lengths: long, intermediate, and short. Tampa Electric monitors the market to obtain the most favorable prices from sources that meet the needs of the generating stations. The use of daily and weekly publications, independent research analyses from industry experts, discussions with suppliers, and coal solicitations aid the company in monitoring the coal market and shaping the company's coal procurement strategy to reflect current market conditions. This allows for stable supply of reliable sources while still providing flexibility to take advantage of favorable spot market opportunities.

Q. Please summarize Tampa Electric's solid fuel, coal and petroleum coke, supply for 2011.

A. Tampa Electric supplied Big Bend's coal needs through a combination of two "base" coal supply agreements that continue through 2014 and a collection of shorter term contracts and spot purchases. These shorter term purchases allowed the supply to adjust for changing coal quality and quantity needs, operational changes and pricing opportunities.

Q. Has Tampa Electric entered into coal supply transactions for 2012 delivery?

A. Yes, Tampa Electric has contracted over two-thirds of its 2012 expected coal needs through bilateral agreements with coal suppliers to mitigate price volatility and ensure reliability of supply. In addition to the two "base" supply agreements for Big Bend Station, Tampa Electric has contracted for a portion of its needs through several shorter term purchases. Tampa Electric anticipates the remaining solid fuel purchases for Big Bend Station and Polk Unit One will be procured through spot market purchases during the fourth quarter of 2011 and in 2012.

Coal Transportation

Q. Please describe Tampa Electric's solid fuel transportation arrangements?

A. Tampa Electric can receive coal at its Big Bend Station via both waterborne delivery and rail delivery. Once delivered to Big Bend, Polk Unit 1's solid fuel is re-delivered to Polk Station via trucks from Big Bend Station.

Q. Why does the company maintain multiple coal transportation options in its portfolio?

A. Bimodal solid fuel transportation to Big Bend Station affords the company and its customers 1) access to more potential coal suppliers providing a more competitive, overall delivered cost, 2) the flexibility to switch to either water or rail in the event of a transportation breakdown or interruption on the other mode, and 3) competition for solid fuel transportation contracts for future periods.

Q. Did the bimodal solid fuel transportation prove useful in 2011?

A. Yes. Spring rains were particularly severe in the Midwest this year. Those rainfall quantities caused severe flooding for an extended period of time along the Mississippi River and many of its associated feeder rivers. The availability of rail as well as an adequate supply of inventory allowed Tampa Electric to mitigate any price impacts and avoid any supply interruptions.

Q. Will Tampa Electric continue to receive coal deliveries via rail in 2011 and 2012?

A. Yes. Tampa Electric expects to receive 1.8 million tons in 2011 and up to 2.1 million tons of coal in 2012 for use at Big Bend through the Big Bend rail facility.

As part of the CSX transportation agreement, Tampa Electric receives a per ton reimbursement for each ton of coal delivered, all of which is flowed through to customers through the fuel and purchased power cost recovery clause pursuant to the company's most recent rate case final order.

Q. Please describe Tampa Electric's expectations regarding waterborne coal deliveries?

A. Tampa Electric expects to receive the balance of its solid fuel supply needs as waterborne deliveries to its unloading facilities at Big Bend Station. These deliveries may come through United Bulk Terminal, from other terminals along the Gulf Coast, or from foreign sources. The ultimate source is dependent upon quality, operational needs, and lowest overall delivered cost.

Natural Gas Supply Strategy

Q. How does Tampa Electric's natural gas procurement and transportation strategy achieve competitive natural gas purchase prices for long and short term deliveries?

A. Similar to its coal strategy, Tampa Electric uses a portfolio approach to natural gas procurement. This approach consists of a blend of pre-arranged base, intermediate and swing natural gas supply contracts complemented with shorter term spot purchases. The contracts have various time lengths to help secure needed supply at competitive prices and maintain the ability to take advantage of favorable natural gas price movements. Tampa Electric purchases its physical natural gas supply from approved counterparties, enhancing the liquidity and diversification of its natural gas supply portfolio. The natural gas prices are based on monthly and daily price indices, further increasing pricing diversification.

Tampa Electric has improved the reliability and cost effectiveness of the physical delivery of natural gas to its power plants by diversifying its pipeline transportation assets, including receipt points, and utilizing pipeline and storage tools to enhance access to natural gas supply during hurricanes or other events that constrain supply. On a daily basis, Tampa Electric strives to obtain reliable supplies of natural gas at favorable prices in order to mitigate costs to its customers. Additionally, Tampa Electric's risk management activities reduce natural gas price volatility.

Q. Please describe Tampa Electric's diversified natural gas transportation arrangements.

A. Tampa Electric receives natural gas via the Florida Gas Transmission ("FGT") and Gulfstream Natural Gas System, LLC ("Gulfstream") pipelines. The ability to deliver natural gas directly from two pipelines enhances the fuel delivery reliability of the Bayside Power Station, comprised of two large natural gas combine-cycle units and four aero derivative combustion turbines. Natural gas can also be delivered to Big Bend Station directly from Gulfstream to support the new aero derivative combustion turbine and to Polk Station from FGT to support the four natural gas combustion turbines at that station.

Q. Are there any changes to Tampa Electric's pipeline capacity for the balance of 2011 or 2012?

A. Yes. Florida Gas Transmission's Phase VIII upgrade went into service April 1, 2011. Tampa Electric contracted for a small portion of this Phase VIII capacity. Tampa Electric reserved 50,000 MMBtu of capacity beginning in April of 2011. The Phase VIII capacity provides enhanced reliability for delivery of gas supply and allows Tampa Electric to meet its peak system demands.

Q. What actions does Tampa Electric take to enhance the reliability of its natural gas supply?

A. Tampa Electric maintains natural gas storage capacity with Bay Gas Storage near Mobile, Alabama to provide operational flexibility and reliability of natural gas supply. Currently the company reserves 1,250,000 MMBtu of storage capacity.

In addition to storage, Tampa Electric maintains diversified natural gas supply receipt points in FGT Zones 1, 2 and 3. Diverse receipt points reduce the company's vulnerability to hurricane impacts and provide access to lower priced gas supply.

Tampa Electric also reserves capacity on the Southeast Supply Header ("SESH"). SESH connects the receipt points of FGT and other Mobile Bay area pipelines with natural gas supply in the mid-continent. Mid-continent natural gas production has grown and continues to increase through non-conventional shale gas and the Rockies Express. Thus, SESH gives Tampa Electric access to secure, competitively priced on-shore gas supply for a portion of its portfolio.

Q. Has Tampa Electric entered any natural gas supply transactions for 2012 delivery?

A. Yes, by the end of September 2011, over two-thirds of the company's expected natural gas requirements will be under contract.

Q. Has Tampa Electric reasonably managed its fuel procurement practices for the benefit of its retail customers?

A. Yes. Tampa Electric diligently manages its mix of long, intermediate, and short term purchases of fuel in a manner designed to reduce overall fuel costs while maintaining electric service reliability. The company's fuel activities and transactions are reviewed and audited on a recurring basis by the Commission. In addition, the company monitors its rights under contracts with fuel suppliers to detect and prevent any breach of those rights. Tampa Electric continually strives to improve its knowledge of fuel markets and to take advantage of opportunities to minimize the costs of fuel.

Projected 2012 Fuel Prices

Q. How does Tampa Electric project fuel prices?

A. Tampa Electric reviews fuel price forecasts from sources widely used in the industry, including the New York Mercantile Exchange ("NYMEX"), Wood Mackenzie, the Energy

Information Administration, and other energy market information sources. Futures prices for energy commodities as traded on the NYMEX form the basis of the natural gas and No. 2 oil market commodity price forecasts. The commodity price projections are then adjusted to incorporate expected transportation costs and location differences.

Coal prices and coal transportation prices are projected using contracted pricing and information from industry-recognized consultants and published indices and are specific to the particular quality and mined location of coal utilized by Tampa Electric's Big Bend Station and Polk Unit 1. Final as-burned prices are derived using expected commodity prices, associated transportation costs.

Q. How do the 2012 projected fuel prices compare to the fuel prices projected for 2011?

A. Projected fuel prices are expected to increase in 2012 compared to 2011 as the global economy is projected to improve and inventory surpluses diminish.

Q. What are the market drivers of the expected 2012 price of natural gas?

A. The current market forecasts are projecting a slight increase to natural gas pricing in 2012 as compared to 2011. An anticipated improvement to the economy and market adjustment to shale gas production is expected to raise the price slightly but not dramatically.

Q. What are the market drivers of the change in the price of coal?

A. International demand for coal and petroleum coke has increased the price of coal for several years, and particularly in 2011 for Illinois Basin coal as it found ways to be exported to Europe, South Africa and India. Additionally, the addition of FGD scrubbers on a number of coal plants has made the lower cost Illinois Basin coal viable in those units thus increasing the demand and price for Illinois Basin coal. Conversely, low natural gas prices caused higher cost coal-fired generation to be displaced by lower cost natural gas combined cycle units. These changes are expected to increase the price of Illinois Basin coal in 2012 and beyond. However, with the contract pricing of Tampa Electric's base agreements, the impact should be reduced through 2014.

Q. Did Tampa Electric consider the impact of higher than expected or lower than expected fuel prices?

A. Yes. Tampa Electric prepared a scenario in which the forecasted fuel prices were 35 percent higher for both natural gas and No. 2 oil. Similarly, Tampa Electric prepared a scenario in which the forecasted fuel prices were 35 percent lower for both natural gas and No. 2 oil. Due to Tampa Electric's generating mix as well as its Commission approved hedging strategy the impact the fuel cost under either scenario is mitigated.

Risk Management Activities

Q. Please describe Tampa Electric's risk management activities.

A. Tampa Electric complies with its risk management plan as approved by the company's Risk Authorizing Committee. Tampa Electric's plan is described in detail in the Risk Management plan filed August 1, 2011 in this docket.

Q. Has Tampa Electric used financial hedging in an effort to help mitigate the price volatility of its 2011 and 2012 natural gas requirements?

A. Yes. Tampa Electric hedged a significant portion of its 2011 natural gas supply needs and a portion of its expected 2012 natural gas supply needs in accordance with its plan. Tampa Electric will continue to take advantage of available natural gas hedging opportunities in an effort to benefit its customers, while complying with the company's approved Risk Management Plan. The current market position for natural gas hedges was provided in the Hedging Information Report submitted on August 15, 2011.

Q. Are the company's strategies adequate for mitigating price risk for Tampa Electric's 2011 and 2012 natural gas purchases?

A. Yes, the company's strategies are adequate for mitigating price risk for Tampa Electric's natural gas purchases. Tampa Electric's strategies balance the desire for reduced price volatility and reasonable cost with the uncertainty of natural gas volumes. These strategies are described in detail in Tampa Electric's Risk Management Plan filed August 1, 2011.

Q. How does Tampa Electric determine the volume of natural gas it plans to hedge?

A. Tampa Electric projects the quantity or volume of natural gas expected to be consumed in its power plants. The volume hedged is driven by the projected total natural gas consumption in its combined-cycle plants by month and the time until that natural gas is needed. Based on those two parameters, the amount hedged is maintained within a range authorized by the company's Risk Authorizing Committee and monitored by the Risk Management department. The market price of natural gas does not affect the percentage of natural gas requirements that the company hedges since the objective is price volatility reduction, not price speculation.

Q. Were Tampa Electric's efforts through July 31, 2011 to mitigate price volatility through its non-speculative hedging program prudent?

A. Yes. Tampa Electric has executed hedges according to the risk management plan filed with this Commission, which was approved by the company's Risk Authorizing Committee. On April 1, 2011, the company filed its 2010 hedging results as part of the final true-up process. Additionally, Commission Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, requires the utilities to file a Hedging Information Report showing the results of hedging activities from January through July of the current year. The Hedging Information Report facilitates prudence reviews through July 31 of the current year and allows for the Commission's prudence determination at the annual fuel hearing. Tampa Electric filed its Hedging Information Report showing the results of its prudent hedging activities from January through July 2011 in this docket on August 15, 2011.

Q. Does Tampa Electric expect its hedging program to provide fuel savings?

A. No. The primary objective of the company's hedging program is to reduce fuel price volatility as approved by the Commission. Tampa Electric employs a well-disciplined hedging program. This discipline requires consistent hedging based on expected needs and avoidance of speculative hedging strategies aimed at out-guessing the market. This discipline insures hedges will be in place should prices spike and also means hedges are in place when prices decline. Using this disciplined approach means that much of the volatility and uncertainty in natural gas prices are removed from the fuel cost used to generate electricity for our customers, but does not guarantee fuel savings.

Q. Does this conclude your testimony?

A. Yes, it does.

DIRECT TESTIMONY OF RONALD A. MAVRIDES

Q. Please state your name and business address.

A. My name is Ronald A. Mavrides and my business address is 4950 West Kennedy Blvd., Suite 310, Tampa, Florida 33609.

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

A. I am employed by the Florida Public Service Commission as a Professional Accountant in the Office of Auditing and Performance Analysis.

Q. How long have you been employed by the Commission?

A. I have been employed by the Florida Public Service Commission since October 2007.

Q. Briefly review your educational and professional background.

A. In 1990, I received a Bachelor of Science degree from the University of Central Florida with a major in accounting. I am also a Certified Government Auditing Professional and a Certified Management Accountant.

Q. Please describe your current responsibilities.

A. I perform conservation, environmental, hedging, and staff-assisted rate case audits. Also, I perform various other financial audits of electric, gas, and water and wastewater utilities.

Q. Have you previously presented testimony before this Commission?

A. Yes. I presented testimony in the Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor in Docket No. 090001-EI and Docket No. 100001-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Progress Energy Florida, Inc. (PEF, Company, or Utility) which addresses the Utility's August 1, 2010, through July 31, 2011, hedging activities. The audit report is filed with my testimony and is identified as Exhibit RAM-1.

Q. Was this audit prepared by you or under your direction?

A. Yes, it was prepared by me.

Q. Please describe the work performed in this audit.

A.

<u>Accounting Treatment</u>

We reviewed PEF's Prior Year Hedging Results as filed on April 1, 2011 and the Current Year Hedging Information filed on August 15, 2011. We examined the report for reasonableness and used it as a basis for our sample. We requested a listing of each futures, options, and swap contracts executed by PEF for the 12-month period covered by the Hedging Information Report. We requested the volumes of each fuel PEF actually hedged using a fixed contract or instrument. We tested 20 sample transactions, choosing an array of transaction types throughout the 12-month period for each hedged fuel type, including diesel fuel and transportation fuel surcharges that were included in the hedging programs by Commission Order PSC-02-1484-FOF-EI, issued October 30, 2002 in Docket No. 011605-EI and as clarified by FPSC Order No. PSC 08-0316-PAA-EI, issued May 14, 2008 and FPSC Order No. PSC-08-0667-PAA-EI, issued October 8, 2008 in Docket No.080001-EI. We traced these transactions to the general ledger and trade tickets, and then to the resulting wire transfers. We requested the names and actual signatures of the persons authorized to make wire transfers to the financial institutions handling the hedging transactions, and compared them to the signatures appearing on the wire transfers reviewed in our sampled transactions. The hedging transactions complied with the Risk Management Plan.

Gains and Losses

We recalculated 20 sample transactions selected from the Hedging Information Report and recalculated the gains/losses by multiplying the volume by the difference between the fixed price and the settlement price as represented on the third-party trading tickets. We then compared them to the recorded gains/losses per the general ledger. We determined they flowed through the fuel and purchased power cost recovery clause as either a charge or a credit as required in Order No. PSC-02-1484-FOF-EI. When there was existing inventory, the inventory account was adjusted, and when there was no existing inventory, the gains/losses flowed through the fuel expense account.

Hedged Volume and Limits

We obtained and reviewed PEF's Risk Management Plan. We compared the percentage limits of fuel hedged in the Risk Management Plan with the actual volumes of fuel hedged that were actually burned. The volumes of fuel hedged that were actually burned fall within the percentage limits delineated in the Risk Management Plan, with the single exception of heavy oil, which falls below the projected Risk Management Plan goal because of weather conditions in December 2010 and April 2011. A higher quantity of oil burned than planned resulted in a smaller percentage hedged.

Tolling Arrangements

We reviewed the existing tolling arrangements. We tested all transactions for one vendor for one month by tracing the vendor's invoices to the A-7 schedule, and reviewed the accompanying master contract with this vendor. PEF had three outstanding tolling arrangements, with one more pending. The treatment of the tolling arrangements appears proper.

Q. Please review the audit findings in this audit report, RAM-1, which addresses the hedging activities of PEF from August 1, 2010 through July 31, 2011.

A. There were no audit findings in the audit report.

Q. Does this conclude your testimony?

A. Yes.

DIRECT TESTIMONY OF KATHY L. WELCH

Q. Please state your name and business address.

A. My name is Kathy L. Welch, and my business address is 3625 N.W. 82nd Ave., Suite 400, Miami, Florida, 33166.

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

A. I am employed by the Florida Public Service Commission as a Public Utilities Supervisor in the Office of Auditing and Performance Analysis.

Q. How long have you been employed by the Commission?

A. I have been employed by the Florida Public Service Commission since June, 1979.

Q. Briefly review your educational and professional background.

A. I have a Bachelor of Business Administration degree with a major in accounting from Florida Atlantic University and a Masters of Adult Education and Human Resource Development from Florida International University. I have a Certified Public Manager certificate from Florida State University. I am also a Certified Public Accountant licensed in the State of Florida, and I am a member of the American and Florida Institutes of Certified Public Accountants. I was hired as a Public Utilities Analyst I by the Florida Public Service Commission in June of 1979. I was promoted to Public Utilities Supervisor on June 1, 2001.

Q. Please describe your current responsibilities.

A. Currently, I am a Public Utilities Supervisor with the responsibilities of administering the District Office and reviewing work load and allocating resources to complete field work and issue audit reports when due. I also supervise, plan, and conduct utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you presented testimony before this Commission or any other

regulatory agency?

A. Yes. I have testified in several cases before the Florida Public Service Commission. Exhibit KLW-1 lists these cases.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Florida Power & Light Company (FPL or Utility) which addresses the Utility's filing in Docket No. 110001-EI Fuel and purchased power cost recovery clause for costs associated with its hedging activities. We issued an audit report in this docket for the hedging activities on September 15, 2011. This audit report is filed with my testimony and is identified as Exhibit KLW-2.

Q. Was this audit prepared by you or under your direction?

A. Yes, it was prepared under my direction.

Q. Please describe the work you performed in these audits.

A. Accounting Treatment

We obtained a summary schedule of all financial futures, options and swaps that were executed by the utility for the 12-month period ended July 31, 2011. We reconciled the monthly gain or loss to the company's filing. We traced these gains and losses to the calculation of the average unit cost of gas and oil and to FPL's books and records. FPL's accounting treatment of hedging gains and losses was verified to be in compliance with Commission Order PSC-02-1484-FOF-EI, issued October 30, 2002 in Docket No. 011605-EI and as clarified by FPSC Order No. PSC 08-0316-PAA-EI, issued May 14, 2008 and FPSC Order No. PSC-08-0667-PAA-EI, issued October 8, 2008 in Docket No.080001-EI.

We obtained the monthly level of hedging gains/losses and verified that they are consistent with the requirements of Commission Order in Docket No. 011605-EI and

FPL's Hedging Plans. We also reviewed the company's external auditor's reports and workpapers on derivative activity for the 12-month period ended July 31, 2011.

Contracts

We sampled two contracts, one for natural gas and one for heavy oil, and reviewed the contracts to ensure that they were in compliance with the Company's hedging plans.

Gains and Losses

We traced the monthly hedging gains and losses to the supporting documents that were used to prepare FPL's filing. FPL provided the "Derivative Settlements-All Instruments" report that shows the calculation of all gains and losses by deal options and swaps made by each counter party. This report was traced to the filing. A sample of the October 2010 natural gas and September 2010 heavy oil transactions were selected for testing. The deals sampled were traced to confirmation letters, bank invoices, deal forms, and purchase statements. In addition, the settle price was traced to Platt's and NYMEX market data. In order to trace the September and October 2010 gains and losses to the general ledger, account 151 Fuel Inventory, we first reconciled the gain and losses to the "Monthly Gas Closing Report" and "Allocation of Oil Financing Instrument" report, which, in turn, were reconciled to the general ledger.

Quantity of Gas and Residual Oil

We obtained the 2010 Risk Management Plan and the Planned Position Strategy (PPS) procedures, which show the hedged targets by months. The natural gas and the heavy oil actual percentage hedged were compared to the target hedged and verified to the specified tolerance bands. If the actual percent hedged of a particular month was not within the tolerance band, then a rebalance would be required. The rebalancing was implemented by either purchasing or selling the swaps to meet the established targets. We verified and recalculated the percent of hedge amounts and the rebalancing by month.

No exceptions were noted.

Value At Risk (VaR)

We verified that the Value At Risk (VaR) Activities were within the transaction limits and authorization as stated in the Risk Management Plans.

Segregation of Duties

We reviewed the procedures for separating duties and had no exceptions.

Q. Please review the audit findings in this audit report, Exhibit KLW-2.

A. There were no findings in this audit related to hedging activities.

Q. Does that conclude your testimony?

A. Yes.

DIRECT TESTIMONY OF DONNA D. BROWN

Q. Please state your name and business address.

A. My name is Donna D. Brown, and my business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida, 32399.

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

A. I am employed by the Florida Public Service Commission as a Professional Accountant in the Office of Auditing and Performance Analysis.

Q. How long have you been employed by the Commission?

A. I have been employed by the Commission since February 2008.

Q. Briefly review your educational and professional background.

A. I graduated from Florida A&M University's School of Business & Industry in 2006 with a Bachelor of Arts degree in accounting.

Q. Please describe your current responsibilities.

A. Currently, I am a Professional Accountant with the responsibilities of managing regulated utility financial audits. I am also responsible for creating audit work papers and programs to meet the specific purpose of each audit.

Q. Have you presented testimony before this Commission?

A. Yes,

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Gulf Power Company (Company or Utility) which addresses the Utility's filing in Docket No. 110001-EI Fuel and purchased power cost recovery clause for costs associated with its hedging activities. We issued an audit report in this Docket for the hedging activities on September 30, 2011. This audit report is filed with my testimony and is identified as Exhibit DDB-1.

Q. Was this audit prepared by you or under your direction?

A. Yes, it was prepared by me and other audit staff under my direction,

Q. Please describe the work you performed in this audit.

A.

Hedging Transaction and Information Report Verification

We reviewed Gulf Power Company's 2010 and 2011 Risk Management Plans for Fuel Procurement filed in Docket No. 090001-EI and Docket No. 100001-EI respectively. We compared pricing strategy included in the plan to the Hedging Reports for the 12 months ended July 31, 2011 as filed by Gulf Power Company on April 1, 2011 and August 15, 2011.

Accounting Treatments for Financial Contracts

We obtained Gulf Power Company's supporting detail of the hedging settlements for the 12 months ended July 31, 2011. The support documentation was traced to the general ledger transaction detail. We reviewed the compliance of the hedging settlements to the Risk Management Plan and verified that the accounting treatment for the hedging transactions and any transaction costs, were consistent with Commission Order PSC-02-1484-FOF-EI, issued October 30, 2002 in Docket No. 011605-EI and as clarified by FPSC Order No. PSC 08-0316-PAA-EI, issued May 14, 2008 and FPSC Order No. PSC-08-0667-PAA-EI, issued October 8, 2008 in Docket No.080001-EI.

Risk Management Plan

We reviewed the quantity limits, individual and group transaction limits and authorizations, as well as the procedures for separating duties related to the hedging program as set forth in the Risk Management Plan. We also obtained Gulf Power Company's analysis of the monthly percent of fuel hedged in relation to fuel burned, the applicable average price of the financial transactions settled, and the average costs of natural gas purchased for the 12 months ended July 31, 2011 and reviewed for reasonableness. The hedging transactions complied with the Risk Management Plan.

Q. Does the staff audit report of Gulf Power Company which addresses the Utility's annual Hedging Information Report and marked as Exhibit DDB-1 contain any findings noting any errors or exceptions taken by staff?

A. No it does not.

Q. Does this conclude your testimony?

A. Yes it does.

DIRECT TESTIMONY OF TOMER KOPELOVICH

Q. Please state your name and business address.

A. My name is Tomer Kopelovich and my business address is 4950 West Kennedy Blvd., Suite 310, Tampa, Florida 33609.

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

A. I am employed by the Florida Public Service Commission as a Regulatory Analyst II in the Office of Auditing and Performance Analysis.

Q. How long have you been employed by the Commission?

A. I have been employed by the Florida Public Service Commission since October 2002.

Q. Briefly review your educational and professional background.

A. I have a Bachelor of Business Administration Degree with a major in finance from the University of South Florida. I am a Certified Public Accountant licensed in the State of Florida. I was hired as a Professional Accountant by the Florida Public Service Commission in October 2002. I am currently a Regulatory Analyst II.

Q. Please describe your current responsibilities.

A. I plan and conduct utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you previously presented testimony before this Commission?

A. Yes. I presented testimony in Docket No. 090001 Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive factor on behalf of Commission staff.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Tampa Electric Company (TEC, Company, or Utility) which addresses the Utility's August 1, 2010, through July 31, 2011, hedging activities. The audit report is filed with my testimony and is identified as Exhibit TK-1.

Q. Was this audit prepared by you or under your direction?

A. Yes, it was prepared by me.

Q. Please describe the work performed in this audit.

A.

General

We reviewed the information presented in the Utility's Hedging Information Reports that were filed on April 1, 2011, and August 15, 2011.

Swap Transactions

We checked the swap transaction price against the market future prices as of the date the Utility entered the swap and found that the prices were the same.

Accounting Treatment

We obtained a schedule of all financial futures, options, and swap contracts that were executed by the Utility from August 1, 2010, through July 31, 2011 and verified that the accounting treatment for the hedging transactions and any transaction costs for consistency with Commission Order PSC-02-1484-FOF-EI, issued October 30, 2002 in Docket No. 011605-EI and as clarified by FPSC Order No. PSC 08-0316-PAA-EI, issued May 14, 2008 and FPSC Order No. PSC-08-0667-PAA-EI, issued October 8, 2008 in Docket No.080001-EI. In addition, we reviewed the volumes of each fuel the Utility actually hedged using a fixed price contract or instrument. We also requested the types of hedging instrument the Utility used and the average period for all hedges, options premiums, futures gains and losses and swap settlements. We reviewed the listing and a sample of contracts.

<u>Gains and Losses</u>

We reviewed a sample of gains and losses. We recalculated the gains and losses by multiplying the traded volume by the difference between fixed price and settlement price (NYMEX price). We reconciled the calculated monthly gains and losses to the Utility's general ledger. We traced general ledger numbers to the Mark to Market Report and supporting journal entries. We reconciled the general ledger amounts and the Mark to Market Report to the Utility's filing.

<u>Hedged Volume and Limits</u>

We reviewed the TEC Risk Management Plans for 2010 and 2011. We compared the actual percentage fuel hedged on a monthly basis to the allowable minimum and maximum limits prescribed by the Risk Management Plan.

<u>Tolling Arrangements</u>

We reviewed the existing tolling arrangements. We tested all transactions for one vendor for one month by tracing the vendor's invoices to the A-7 schedule, and reviewed the accompanying master contract with this vendor. TEC has three outstanding tolling arrangements. The treatment of the tolling arrangements appears proper.

<u>Separation of Offices</u>

We reviewed the Risk Management Plan and work papers for the internal audit related to front, middle, and back offices. We requested the Utility to answer a series of questions regarding the front, middle, and back offices. We determined that there are separation of duties between the front office, middle offices, and back offices.

Q. Please review the audit findings in this audit report, RAM-1, which addresses the hedging activities of PEF from August 1, 2010 through July 31, 2011.

A. There were no audit findings in the audit report.

Q. Does this conclude your testimony?

A. Yes.

CHAIRMAN GRAHAM: Okay.

MS. BENNETT: And, Mr. Chairman, there are exhibits associated with these witnesses that we would also ask be moved into the record. But prior to that, Staff will ask that you mark and move the Comprehensive Exhibit List into the record, and the list itself is Exhibit 1.

CHAIRMAN GRAHAM: We will move the Comprehensive Exhibit List into the record.

MS. BENNETT: And then we would ask that the prefiled exhibit, exhibits of the excused witnesses be moved into the record. And these exhibits are Numbers 2 through 16 for Florida Power & Light, 23 through 24 for Progress Witness McCallister, 28 through 29 for FPUC, 31 through 40 for Gulf, and 41 through 49 for TECO, and 50 through 54 for Staff's audit witnesses. We ask that those be moved into the record at this time.

CHAIRMAN GRAHAM: We will move all those exhibits that were just read by Staff into the record.

(Exhibits 1 through 85 marked for identification.)

(Exhibits 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 23, 24, 28, 29, 31, 32, 33, 34, 35, 36, 37, 38, 39, 40, 41, 42, 43, 44, 45, 46, 47, 48, 49, 50, 51, 52, 53 and 54 admitted into the record.)

MS. BENNETT: And finally, Staff has sponsored Exhibits 55 through 85, and we believe that all of the parties, except for FIPUG, agree to the entrance of all of those Staff exhibits into the record. I think FIPUG may want to talk to you about some related to Progress Energy of Staff's exhibits. So before you enter Staff's exhibits, perhaps you would like to confer with FIPUG as to any objections that he might have.

CHAIRMAN GRAHAM: Mr. Moyle.

MR. MOYLE: A couple of concerns and objections that FIPUG would have. One relates to a deposition that is proposed to be entered of a Progress witness.

First, as sort of a philosophical point, we've kind of gone round and round about depositions being entered when you have witnesses here. We think it's better to have the witnesses take the stand and say what they're going to say rather than dumping a deposition in that doesn't give you all the benefit of hearing their testimony and it's a cold record. That's a policy piece.

But specifically with respect to the portion of the depo that we object to, it's found on page 45, lines 10 through 15. And I can probably tell you what it relates to by also telling you we object to the introduction of documents that are found in production request number 19 and number 20. And for the record, these are identified as Bate stamp numbers PEF-11FL-00474 through PEF-11FL-00478. Those are documents responsive to a production request number 19. And also production request number 20, the documents that Staff is trying to enter in are PEF-11FL-00479 through PEF-11FL-00559.

And what are these? These are a whole bunch of reports from rating agencies that Staff said "Give us rating agency reports that are out there," and they gave them a whole bunch of rating agency reports. There's also -- the person who signed the affidavit read the agency, the rating agency reports and then put forth information in an interrogatory answer based on his reading of these agency reports. So, you know, it's double hearsay. You got the, you got the documents itself being offered and there's nobody here to authenticate them. There's nobody from Standard & Poor's to say, "I authored this and I'm here to answer questions about it." It's just an attempt to dump this into the record.

So we would object on the grounds of hearsay and authenticity to those, those documents coming in and anything related to what's contained in those documents.

And the portion of the depo that I described is just four or five lines, but when the witness referenced these documents. So we, we're trying to keep a clean record in this case that anything rating agencies say, you know, if they want to say it, you know -- we've got a lot of good, smart lawyers here. They can figure out how to prefile testimony, come in, and say it. But to just take these reports and dump them in, we would object strenuously to, to that coming in.

MS. BENNETT: Mr. Chairman, may I make a suggestion? The -- at this point in the proceeding, if we could just enter everything except the two exhibits that Mr. Moyle has objections to into the record, and then we can address those during the cross-examination of the witnesses for Progress, that might be the more appropriate time to -- I know Mr. Moyle just did a good job of arguing his points, but it would be more appropriate if we could address it with Progress's witnesses when they're on the stand.

CHAIRMAN GRAHAM: All right. The question I have is so we're going to address the objections that Mr. Moyle had when we have the witnesses on the stand?

MS. BENNETT: Yes, sir.

MR. BURNETT: Mr. Chairman, if I may.

CHAIRMAN GRAHAM: Yes.

MR. BURNETT: I do have some concern about that just because I don't intend to offer these exhibits. These are Staff exhibits going in the composite. I don't know if Staff intends to ask questions on this, but I think the legal argument may be more appropriate now as the witness certainly can't opine on the legal issues. And since Mr. Moyle has made his brief response, I would ask that perhaps we would be able to do so as well at this time, and even if we do proceed, without just leaving Mr. Moyle's comments unresponded to.

CHAIRMAN GRAHAM: Actually what I would like to do right now is move the exhibits in that Mr. Moyle didn't have an objection to, the Staff exhibits, and we'll hold off on the ones that he did have objection to so the Commissioners up here can pull that stuff and look it over. And then we'll move forward with whatever Staff recommendation is. So let's take about a 15-minute break. Well, first of all, let's move the exhibits in -- Ms. Bennett, for the record, which exhibits are we now moving in?

MS. BENNETT: We're moving in all of Staff's exhibits, 55 through 85, with the exception and, Mr. Moyle will help me make sure I'm correct, with the exception of 56 and 77.

MR. MOYLE: Yeah. And I think we might have a little bit of a disconnect with respect to how we identified them. I identified them as certain productions, PODs that, that were provided, and I have POD 19 and 20. And interrogatory answer 108, there's an interrogatory answer and then there's two PODs that address this issue. And then at lines 10, I'm sorry, page 45, line 10 through 15, of, of a deposition. And they all address the same issue, but, I'm sorry, I don't know exactly where they are in your exhibit list.

CHAIRMAN GRAHAM: This is what we'll do. We'll just hold off, we'll take a 15-minute break so we can identify with the numbers that we have in front of us what's being pulled and what's not being pulled, and also gives us time to pull these things out and read them over.

MS. BENNETT: Okay.

CHAIRMAN GRAHAM: So we will take a break until about a quarter after 10:00.

(Recess taken.)

CHAIRMAN GRAHAM: All right. I think Staff has got hard copies for us, in front of us. I guess the first question is, Mr. Moyle, are these -- are we talking about the same issues?

MR. MOYLE: Yes, sir. And I think it might help because when the deposition was sent electronically, somehow the pagination was a little, little different. So I thought maybe that I could just read into the record the brief paragraph to which FIPUG has its objection so there's no ambiguity or lack of clarity on that piece.

CHAIRMAN GRAHAM: Sure.

MR. MOYLE: And on the exhibit that your Staff just passed out, it's found on page 45, starting at line 9.

CHAIRMAN GRAHAM: It's Exhibit Number 56. At the top of the page it says "45," at the bottom of the page it says "101."

MR. MOYLE: That's right. And, and the answer that, that we seek to not have included is, quote, Yes, the company would still pay for those fuel costs. I think we have expressed in our response to Staff interrogatory 108 the concerns that we have seen by the credit rating agencies, you know, the concern about the regulatory environment in Florida, and so costs to borrow in the future would be hampered by a deferral of our fuel costs today.

That is the only portion of the deposition, notwithstanding the philosophical objection on the depos coming in, you know, that we maintain the objection on hearsay grounds and authenticity as it related to that comment that I just read.

CHAIRMAN GRAHAM: Let's focus on that one and get a resolution to this one before we move on to the next one.

Staff.

MS. BENNETT: Before we start, I think Progress Energy wanted to take a position also.

MR. BURNETT: Certainly. Mr. Chairman, would you just like to hear the response on just this deposition section --

CHAIRMAN GRAHAM: Sure. Yes.

MR. BURNETT: -- at issue now or the total response to all the arguments Mr. Moyle has made about the PODs? I can do them all together or do them one off, however you like.

CHAIRMAN GRAHAM: Whichever way you think I'd understand it the best.

MR. BURNETT: All right. I'll do them all together then.

As to the deposition section that was just read, and I think this will go nicely if I get to the legal arguments behind it too, this is a witness testifying. There is a characterization, and she mentions that the credit rating agency concerns were the same as the company. So this is a company witness saying if you look to this, we have similar concerns based on something. So there's no hearsay there. The witness is actually testifying to what her perception and the company's view is. So I think it's completely inapplicable with respect to the deposition.

As to the underlying documents, Mr. Moyle raised two concerns. First one, authenticity. Second one, hearsay.

Authenticity. First of all, I would say that if this is not directly on, it's in the spirit of Section 90.901(b) as a self-authenticating document. This is likened to a periodical or a newspaper just like the *Wall Street Journal*. If you look at these, you go to www.fitch.com, moodys.com, standardandpoors.com, this is something that can easily be pulled up off the internet. I don't believe Mr. Moyle is actually suggesting that these copies are inaccurate, that they've somehow been altered or we've filled in new words or anything, so these are easily verifiable just like a periodical.

Secondly, think of the implication of that in a regulatory proceeding. So anything that comes in in a rate case, all the massive amounts of documents that are going to come in, we're going to have a record custodian from each one of those agencies come in and testify if we do a record custodian deposition or have affidavits sent in. In an administrative proceeding that just doesn't make sense, given the amount of volume of paper and the things you guys deal with and that we deal with in these proceedings. So it just doesn't make good sense from an administrative perspective.

As to the hearsay, first of all, Section 120.57(1)(c) says that you can rely on hearsay, again so long as it's supplementing or explaining evidence and it's not the sole basis on which you rely.

Next, we assert that this is probably not hearsay at all. It's not offered to prove the truth of the matter asserted and has independent legal significance. So under 90.801 and 02, this is not hearsay at all. It's just to show that investment agencies are watching Florida, they're watching what's going on here, and they're making public statements. Frankly, I don't care if the statements there are true or false or not. It's that people are watching and they have perceptions. So that's the independent legal significance of this, not the truth of the matter asserted.

Third, Section 90.803(17) says that market reports, commercial publications are exempt from the hearsay rule. So there's a specific hearsay exception for this documentation as well.

MR. MOYLE: Can I have a rebuttal opportunity at some point?

CHAIRMAN GRAHAM: Yes.

MS. BARRERA: Yes. In response to the objections that Mr. Moyle has, first of all, I'm going to reiterate that hearsay is allowed under 120.57(1)(c) where it shall be used for the purpose of supplementing or explaining other evidence, but it shall not be sufficient in itself to support a finding unless it would be admissible over objections in civil actions.

Under -- even if it was hearsay, which, you know, we don't believe it is, there's a hearsay exception under Evidence Code 90.803(6)(a) of records of regularly conducted business activity, which I would assume that since the witness relied on these records, that that -- those reports are, in fact, records that the business of the utility relies on to project and to work on their projections and on, and for planning purposes.

Also, they are market reports, which under 90.803(17) are available to the public and are used upon by the public as well as the utility.

The second issue that I have is regarding the deposition question. It's a question relied upon by an expert, which Marcia Olivier is. First of all, it's the answer to a question that Mr. Moyle asked. Staff didn't ask that question. But at the same time, it is the answer to a question that an expert relied upon using these Standard & Poor's and these reports. Therefore, under 90.702 the testimony is admissible.

If I may cite a case, *Vega vs. State Farm Mutual Auto*, 5th DCA, 45 So.3d 43, where the court, the court found that an expert may rely even upon hearsay in arriving at an opinion, provided that the hearsay is of the type reasonably relied upon by experts in the field. So the argument is it's not, it's not hearsay. Even if it was hearsay, it is admissible under 120.57(1)(c). It's also admissible under Florida Rules of Civil Procedure and the Florida Evidence Code, as well as by case law.

CHAIRMAN GRAHAM: Mr. Moyle.

MR. MOYLE: There's a lot, a lot to cover after the arguments by counsel for Progress and Staff.

First, let me suggest that the argument that it's relied on by an expert is not a sound argument by the own admission of Progress's witness. If you look at the exhibit that was provided to you -- let me -- I asked her the question whether she was an expert and she couldn't answer it. This is, on your exhibit, page 67. I asked her on line 10, "Hypothetically, are you an expert? Are you being tendered as an expert witness? Do you know?" And her answer was, quote, I'm not sure. I'm the witness on the cost that's been included in the fuel factors for recovery. So I guess when you say expert, expert on what?

And I went on and said, "On your fuel recovery." And she said, "I'm not sure."

So even if she, even if there is an expert, she's talking about being expert in, in fuel recovery. Expertise that would be relied on by a witness that could use this would be somebody who's up here talking about financial implications of a decision, an economist or somebody like that. So the whole notion that, that it comes in as an exception based on expertise, she hasn't even, can't even answer the question that she is an expert.

A couple of other points. The self-authentication, you know, I don't think just because you can pull a document off the Internet that, you know, therefore it becomes self-authenticating. There's pretty strict rules on that.

I think if you all asked your agency clerk to say there's a document that needs to be introduced in a court case, we need it to be authenticated, they would have to go through and sign an affidavit or indicate that it's kept in the regular course of business, that this is a true and correct copy. So the notion that somehow the *Miami Herald*, the *Wall Street Journal*, that those are self-authenticating I think is, you know, is off base.

Counsel for Progress said, well, we're not even offering it to prove the truth of the matter asserted, you know, which brings up the question, well, then why is it even relevant? You know, I mean, we, we are working hard to keep this out because there's no other evidence out there that suggests that, you know, what may or may not happen based on a decision. And your counsel is right with respect to hearsay evidence being allowed to the extent it supplements, you know, factual information that comes in through another witness. But there's no other witness here who says, hi, I'm an expert in Wall Street and rating agencies and here's what's going to happen.

You know, what is trying to be done is a backdoor effort to try to get this stuff in and then try to rely on it. We, we are concerned about relying on it as a basis for a finding of fact. And Chapter 120 says you can't do that, you can't rely on hearsay as the sole basis for a finding of fact. You know, we don't think there's anything else in the record relating to these Wall Street rating agency statements, and that's part of the reason why we're working, working hard to try to keep it out because we don't think any finding is appropriately made because there's nobody here to answer questions about these documents, nobody here to authenticate the documents. And, you know, and those are -- while they may be somewhat inconvenient -- I mean, we haven't gone through all these exhibits, these are the only ones we're raising the objections to, and it is what the law requires. So to the extent that there is a bit of an inconvenience and a burden, you know, that inconvenience and burden happens every day in courts of law and at Division of Administrative Hearings proceedings, and it should, I would argue, be addressed here as well to, you know, to apply the rules of evidence and to, you know, handle proceedings in accordance with that.

The point about, about market reports, that somehow it comes in as an exception under market reports, I think that is, to the extent it's a rain gauge and it's a governmental entity that measures the rain gauge every day, the National Weather Service, what's the temperature, it's matters that are regularly and routinely measured and conducted that have reliability because it's, it's done.

I think to the extent that they were trying to get in evidence about what did the Dow Jones close at on this particular day, that would be more akin to market data that would come in under an exception, but that's not what these documents are. That's not what this response to interrogatory is. These are people's opinions where they're saying I think, I think this, I think that; if, if this, then that. And that is not regularly and routinely collected information and is not the kind of, of market data that would fall within the exception. So we don't think any of those apply, and we think the correct ruling is to keep it out based on the hearsay and the authenticity objections.

MR. BREW: Mr. Chairman.

CHAIRMAN GRAHAM: Yes.

MR. BREW: Could I be heard on this?

CHAIRMAN GRAHAM: Sure.

MR. BREW: This discussion represents in the first instance, and I discussed this with Staff, while PCS is generally opposed to simply putting a deposition in when the witness is here to answer questions, this is a case where you have a witness that can speak to whether she can vouch for the accuracy, content, or context of any of those Wall Street reports. And so that's my basic problem with simply putting the deposition for -- that's been marked as Exhibit 56 simply in the record.

The record will be much clearer if Ms. Olivier can speak to how or what she took those into account in any of her testimony. So I'd strongly support FIPUG in that regard.

Secondly, I believe I heard Mr. Burnett say that the company pointed to the fact that these documents exist and that Wall Street, in fact, pays attention to these proceedings. If we simply wanted to stipulate to those facts, that would be fine. But since there's nobody that can actually -- Mr. Moyle is absolutely correct, that the statements that were offered go to opinions as to the significance of these proceedings to the rating agencies when there's nobody here to speak to that. And that's my concern.

And to the extent that we have a witness that's available that can respond to questions, we should take that up rather than simply mark these documents as exhibits. Thank you.

CHAIRMAN GRAHAM: Mr. Burnett.

MR. BURNETT: Mr. Chairman, thank you. Mr. Brew said something intriguing to me. This is, this -- I think we should ground ourselves of what we're talking about here. This, all this goes to the legal policy issue that we're going to have legal argument on and, if you wish it, legal briefing on, although we don't believe that's required.

I'm happy to accept a stipulation that says that the rating agencies and investment communities watch this Commission closely and write profusely on your actions. That's, that's all that I care about. It's a factor that you guys consider when you're making decisions on deferring anything or taking, setting regulatory policy, or interpreting your past actions. I'm fine with that. Staff asked for these reports in discovery, and I think that's what they were getting at. It's part of the factors that you apply.

So, you know, I think it is distracting to have a mini trial on this. Ms. Olivier will say I have no idea, this is not part of my testimony, I didn't ask for this. She was asked a question by Mr. Moyle in her depo. She did the best she could. But this is not part of what we're here for on substance. I'll take Mr. Brew's stipulation, if it's on the table.

CHAIRMAN GRAHAM: Does that stipulation -- to Mr. Moyle, does that stipulation address your concern?

MR. MOYLE: No, not really.

CHAIRMAN GRAHAM: Why so?

MR. MOYLE: Well, I mean, it's kind of like he just sort of made it up and said, okay, you know. I don't know. I mean, do they watch it? Do they not watch it? I mean, you know, I -- there's no evidence, there's no anything related to it. So, you know, you know, I -- you know, and this is an issue that I'm not sure it's unique to today, and so I would like a ruling on it respectfully.

Because, because here's, and, you know, here's, here's why I think it's important. Not only is it important with respect to what you're doing today, but there may be rate cases in the future and there's this practice to say, well, here's what the rating agencies, you know, will say, will do. And it's not fair, I would maintain it's not fair for people to say, well, here's what the rating -- well, how do you know? Well, I talked to somebody, or I read this report. And, you know, I think it's a fundamental issue and a fundamental problem. I don't think it's proper. If they want to have somebody in that comes in and says I authored this report and here's my concern, you know, have at it. I can ask them questions on cross-examination. But to just take, take this stuff and dump it in is bad practice and not supported by law, we would argue.

CHAIRMAN GRAHAM: Mr. Rehwinkel.

MR. REHWINKEL: Mr. Chairman, Public Counsel intended to try to stay out of this so we could get into the hearing in chief, and I had informed Staff that I had no objections to their exhibits, especially -- particularly these two. And I have to say I, I fully agree with Mr. Moyle and Mr. Brew with respect to their objections.

With respect to the issue or the question posed about stipulation, I have been reviewing Order PSC-100734 that was issued last year on an issue that is very close to what we're talking about today. And while I agree with the objections that my colleagues have raised, I believe that the rating agency information is beside the point and not what the Commission considers when deciding whether to allow some, all, or none of underrecoveries where you have an ongoing prudence determination, what, what you're really going to get to when you see the briefs in this, in this case. So I really saw it as beside the point and not part of the issue before the Commission in a legal sense, so that's why the Public Counsel had tried to stay out of this. But I wanted to say that I support what they say. I don't see a need to stipulate with respect to rating agencies for purposes of what's before the Commission today. Thank you.

CHAIRMAN GRAHAM: Mr. Brew.

MR. BREW: Part of the other concern I had was, was the selected quotes that show up in the interrogatory response. You know, whether the rating agencies understand the distinction between cost recovery and deferral subject to future action is something that also is a distinction that would need to be addressed and it goes to the core legal issue that we'll debate later. So that gets back to my initial objection: Because there's nobody here to explain these types of comments that are in the exhibit that Mr. Moyle referenced to explain either the intended accuracy, the content or the context, I don't think it's information that should be allowed into the record.

CHAIRMAN GRAHAM: Mr. Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman. And I'd like to make a few comments on both of these issues that are interrelated.

I think that this Commission in the past has had evidence entered into the record with objections from a party. And I think that in the past we have determined that we would note the objections and give that information the weight that it deserves.

And as far as this particular issue and to Mr. Moyle's comment on the testimony on Page 45, just looking at, at the testimony, you know, the fact that the witness states, "And so costs to borrow in the future could be hampered by a deferral of our fuel cost today," you know, I think adequately frames the previous statement.

But, again, I think that entering that testimony into the record with the noted objection, we can still move forward and give it the weight that it deserves.

And as far as the information that's included in the response, a request for the production of documents, I certainly, I certainly don't need dozens of articles to let me know that the rating agencies watch what we do. So either, I could go either way on that. But, again, I think the safest bet would be just to enter this information into the record, noting the objections, and this Commission to give it the weight that this and all evidence deserves.

MS. HELTON: Mr. Chairman.

CHAIRMAN GRAHAM: Hold on a second. I have a question for Staff. Progress said earlier when they were talking about hearsay evidence that you could use it when it's supplemental to something that's already been put into the record. Mr. Moyle noted that nowhere else has this come into the record.

MS. BARRERA: Well, this is the issue of why we wanted to have the witness present and have the objections at that point in time. I think the evidence that, which Staff tried to put into the record as a result of the deposition and the questions that we asked really went into whether or not the utility had looked at the effect of a deferral on, and the effect of deferral not only on their credit rating but also on consumers. It's really relevant to this, these proceedings. It's something that we believe the utility relies upon. If we have the witness, we can ask the witness whether or not the utility relies upon these reports. We can even ask the Commission to take judicial recognition of these reports since they exist, you know, on the internet and they're available in general to the public. Whether or not the Commission then decides to give it any weight, that would be up to the Commission, you know, as far as looking into the evidence when it's time to deliberate on the issue.

CHAIRMAN GRAHAM: Do we have this witness?

MS. BARRERA: Yes. Marcia Olivier, she will be one of the witnesses that were not, was not stipulated to. Also, Mr. Garrett was not stipulated to.

So these witnesses are going to be here, they're going to be available. They will be speaking to these issues. Mr. Moyle can cross-examine at that point in time, so can the other Intervenors. And, you know, Staff has a few questions, if they're not asked by anybody else.

So in that frame, I think that once the Commission listens to all the evidence that's being presented, they can then, you can then go ahead and make the determination whether or not to reserve the objection, whether or not to, to accept the testimony and the documents into -- as exhibits, and then give it the weight that the Commission feels is prudent.

CHAIRMAN GRAHAM: Mr. Moyle, I'm going to hold off on making a ruling on your objection and see what we can get, what we can flush out with the witness, and then at that time we'll address it again.

MR. MOYLE: Okay. I appreciate that. I guess the only, the only issue that maybe I need to think about a little bit just as we're kind of going through this, because Staff -- at some point, probably before the witness takes the stand, I need to understand what the ruling is. Because if it's out, then I won't ask any questions about it, and if it's in, then I will, so.

CHAIRMAN GRAHAM: Well, I think what I'm trying to get to, and the other Commissioners can add in, if they want, what I'm trying to get to is making sure that Staff has got what they needed into the record, onto the record; that you have a comfort level on if the witness is an expert or is not an expert or what is she testifying on and what is she not; what is hearsay? And then at that time we can give it the rate -- we can give it the weight that it, that it deserves.

MR. MOYLE: Sure. Maybe we can -- if she's -- we can voir dire her as to her expertise, if that makes sense, and I can ask her about her expertise and whether she has any independent knowledge.

I mean, in her deposition, as Mr. Burnett said, when I asked her the follow-up, "Why do you say that," she goes, "Well, that was what was in our answer to interrogatory 108." So, you know, it's not like, well, I have some independent expertise on that. But we can get that, if we want to do it through voir dire. But I guess just for my planning purposes, at some point I'll need to know are they in or are they out, but however you want to deal with that.

CHAIRMAN GRAHAM: I'm sure there will be a whole lot of rulings between now and the end of that person's testimony.

MR. MOYLE: I appreciate also the opportunity to have this discussion and the time that you've been afforded in allowing us to make the arguments. So thank you for that.

CHAIRMAN GRAHAM: All right, Staff. So let's move, let's move into the record the exhibits 55 through 85, everything except 56 and 77. Those are two that Mr. Moyle objected to.

MS. BENNETT: Yes. Thank you.

CHAIRMAN GRAHAM: So that is now into the record.

(Exhibits 55, 57, 58, 59, 60, 61, 62, 63, 64, 65, 66, 67, 68, 69, 70, 71, 72, 73, 74, 75, 76, 78, 79, 80, 81, 82, 83, 84, and 85 admitted into the record.)

MS. BENNETT: And we will address that, come back and address that when Progress witnesses are on the stand.

CHAIRMAN GRAHAM: We will definitely come back and deal with that so we can make an official ruling on the objection that's on the table.

Okay. So now we're at decisions on proposed stipulations.

MS. BENNETT: The Commission can make a bench decision on the stipulated issues found in the Prehearing Order on pages 31 through 57. Staff has also prepared a chart showing the stipulated issues and another chart showing the non-stipulated issues. And staff is available to answer any questions regarding the proposed stipulations.

CHAIRMAN GRAHAM: Any Commissioners have any questions to Staff for the proposed stipulations?

Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

I do not at this time have a question about a specific stipulation, but I am thinking that it might be helpful to use the chart that the Staff has prepared or the two charts and possibly to go ahead and mark them and enter them into the record. And that might be a way to help us more easily and clearly go through the stipulations, or the issues, those that are stipulated and those that are non-stipulated. So I would pose that, Mr. Chairman, to you or to our Staff.

MS. BENNETT: That would be -- if we could identify the stipulated issues checklist that we provided to all of the parties and to the Commissioners as Exhibit 86, and then the non-stipulated issues checklist could be 87.

COMMISSIONER EDGAR: And so, Mr. Chairman, if you're comfortable with marking those as Staff has suggested, 86 as the stipulated issues checklist, 87 as the non-stipulated issues checklist, then after any questions are addressed, I would be comfortable making a motion referring to Exhibit 86.

CHAIRMAN GRAHAM: Okay. So the stipulated issues checklist is in our script pages 7 and 8, and the non-stipulated issues checklist is page number 6. And that will be Exhibit 86 and 87 respectively.

MS. BENNETT: And if no party has an objection, I would ask that it be moved into the record at this time.

CHAIRMAN GRAHAM: Any parties have any objections? God, I like it when you guys are on one page. We will move those two into the record.

(Exhibits 86 and 87 marked for identification and admitted into the record.)

Okay. Any other Commissioners with questions of the different stipulations we have before us?

Commissioner Brown.

COMMISSIONER BROWN: Thank you. And this is a question for Staff with regard to Issue 34 that's stipulated regarding the effective date. I just want to make sure that the effective date is in uniformity with the other clause dockets in this 01 docket, because I know --

MS. BENNETT: It is not.

COMMISSIONER BROWN: Okay. Thanks.

CHAIRMAN GRAHAM: I didn't hear that. Did you get the answer to your question?

COMMISSIONER BROWN: Yes.

CHAIRMAN GRAHAM: Okay. Any other questions of Commissioners? Are there any other outstanding motions or petitions? No? Any additional preliminary -- Commissioner Edgar.

COMMISSIONER EDGAR: Then -- I didn't mean to jump ahead of you, Mr. Chairman. But if we are in order, then I would move that we adopt all of the stipulations as they are listed on Exhibit 86.

CHAIRMAN GRAHAM: It's been moved and seconded to adopt all the issues as stipulated in Exhibit 86. We're on page 7 and 8. Any further discussion? Seeing none, all in favor, say aye.

(Affirmative response.)

Any opposed?

(No response.)

By your action, you have approved the stipulated issues in Exhibit 86.

Staff, are we to any additional preliminary matters?

MR. BUTLER: Mr. Chairman.

CHAIRMAN GRAHAM: Yes, sir.

MR. BUTLER: I'm sorry. John Butler for

Florida Power & Light Company.

At this point FPL's witnesses have been excused. There are stipulations on all of FPL's issues in this 01 proceeding, and I'd ask that FPL be excused at this time.

CHAIRMAN GRAHAM: Is there any reason why we are not excusing FPL's witnesses? Mr. Moyle.

MR. MOYLE: No. I think, I think, maybe with the exception of Ms. Brownless, I think all of us are geared toward Progress. And so to the extent -- I don't think there are any other issues pending related to any of the other utilities as far as I understand it.

CHAIRMAN GRAHAM: Poor Progress.

MR. BURNETT: I'm all alone.

(Laughter.)

CHAIRMAN GRAHAM: All right. So, all right, so, Staff, there's no reason to hold off on the Florida -- the FP&L witnesses?

MS. BENNETT: No reason.

CHAIRMAN GRAHAM: We can excuse those. And how about for Gulf and TECO?

MR. STONE: We would make similar requests on behalf of Gulf's witnesses and counsel.

MR. BEASLEY: As would we for Tampa Electric, Mr. Chairman.

CHAIRMAN GRAHAM: And nobody else has got any questions or concerns of those witnesses?

Staff?

MS. BENNETT: No objection to their being excused.

CHAIRMAN GRAHAM: You guys are all free to go.

MR. BUTLER: Thank you, Mr. Chairman.

CHAIRMAN GRAHAM: All right. Any other preliminary matters, Staff?

MS. BENNETT: Just one or two. I note that there are some outstanding motions and petitions that will be addressed by the Prehearing Officer on confidentiality, and that this docket does involve confidential information. And if there is confidential information that's presented for discussion, we need to be careful not to voice that information because it will be picked up on the, by the court reporter. So with that, we are finished with the preliminary matters.

CHAIRMAN GRAHAM: Okay.

MR. STONE: Chairman Graham.

CHAIRMAN GRAHAM: Yes.

MR. STONE: Jeff Stone on behalf of Gulf Power Company. Recognizing that you have excused us from the 01 docket, there are a number of stipulations in the 07 docket that I believe affect all the companies with the exception of Progress. And I realize that it would be slightly out of order, but it might be helpful to the smooth running of this proceeding if we could dispense with the 07 stipulated issues, and that would then leave you an orderly presentation of the issues that remain unstipulated in both dockets.

MR. BUTLER: FPL would join in that request.

CHAIRMAN GRAHAM: Imagine that.

MR. REHWINKEL: The Public Counsel would support that request. We also think it would allow us to just focus on Progress, and other employees to return to take care of other matters.

One suggestion I would offer is you could adjourn -- you could recess this docket, take up 07, and then come back into this one.

CHAIRMAN GRAHAM: Do you -- well, I guess the question I have of Staff, do we just lay this docket on the table and then go to 07 and come back?

MS. BROWN: I think that would probably be better. I'm worried about getting the records all mixed up together. I think it would be better to recess 01, go to 07, and then come back.

CHAIRMAN GRAHAM: All right. Now once again, I'm a dumb engineer, so lay it on the table. Recess? Tell me.

MS. BROWN: Yeah. Right.

CHAIRMAN GRAHAM: Which one? Or are they both the same?

MS. BROWN: Say again. I was teasing you.

CHAIRMAN GRAHAM: I don't understand legalese. Is laying it on the table, recessing, are those things all the same?

MS. BROWN: Yes. Yes.

CHAIRMAN GRAHAM: Okay. Then I understand laying it on the table.

Okay. So we will lay Docket 110001 on the table for the time being.

(Proceeding recessed.)

We laid 07 on the table, and we're taking 01 back off the table.

While we're waiting for everybody to clear out, let's take a five-minute recess.

(Recess taken.)

Let's get back to work. Now before we get started, I want to give everybody a heads up. I meant to do this at the beginning, but now will be as good as any. I plan on breaking for lunch around 12:00, or if we get to a nice little stopping spot either just before or just after, but as close to 12:00 as we can get. And probably breaking for an hour and 15 minutes, an hour and a half, and we'll come back. We plan on ending at 5:00. We have some -- some have other commitments, so we will be ending as close to 5:00 as we can, and we'll be starting tomorrow morning once again at 9:30. I just want to make sure everybody knows you can plan your day accordingly. And that all being said, Staff, where are we?

MS. BENNETT: I think we are ready to swear in the remaining witnesses.

CHAIRMAN GRAHAM: Okay. Are those witnesses here? If I can get you to stand, raise your land.

(Witnesses collectively sworn.)

Staff.

MS. BENNETT: At this point in time, the Prehearing Officer afforded each party five minutes for opening statements, with Progress Energy being permitted to go last, if the Chairman so orders, and perhaps to allow Progress additional time in the Chairman's discretion, if it's necessary.

CHAIRMAN GRAHAM: Actually I think what I'll do, not to step around the Prehearing Officer, thank you very much, is give Progress seven minutes. You can use as much as you want to open, as much as you want to close, but you have a total of seven.

MR. BURNETT: Thank you, sir. Would you like me to go first or last? I would like to defer, if it's your pleasure, but I'm happy to do whatever you'd like me to do.

CHAIRMAN GRAHAM: You can do whichever you wish for your seven minutes.

MR. BURNETT: I'll go last then. Thank you, sir.

CHAIRMAN GRAHAM: Okay.

MR. MOYLE: I -- we didn't -- we never had a discussion about who goes first and who goes last when we had the prehearing. I mean, it's their petition. They're the ones seeking the money. I think traditionally the person goes first who has the petition. I'd like to, I'd like to hear what they have to say because I may model some of my opening statement comments in response to theirs, but we never had the conversation.

CHAIRMAN GRAHAM: I was going to say he could just say, hi, I'm Progress, and then close.

(Laughter.)

Yes, ma'am.

MS. KEATING: Mr. Chairman, I'm here for FPUC, and we're on a completely different page, a different issue than these guys. So if I might suggest that perhaps we could go first, or after they have addressed the Progress issues. We'd just like a couple of minutes to address the FPUC issue.

CHAIRMAN GRAHAM: You know, I like the idea of clearing things out of the way, so let's do that.

MS. KEATING: All right. Thank you.

CHAIRMAN GRAHAM: Sure.

MS. KEATING: Mr. Chairman, Commissioners, we appreciate the opportunity to address you regarding FPUC's proposal to use a new demand allocation methodology. As you'll hear more from Ms. Martin later today, FPUC is proposing a demand allocation methodology that it believes better allocates demand costs across FPUC's rate classes because it is based on FPUC-specific information rather than data obtained from Gulf and FPL.

Over the years the prior methodology, which is known as the 12CP and 1/13th AD methodology, has served its purpose, but the reality is that FPUC is not by any stretch similarly situated to either FPL or Gulf, particularly when it comes to load data.

As Ms. Martin will explain, various circumstances over the past year prompted the company to Commission a study by a noted expert in the field to see if he could come up with a methodology that was specific to FPUC. Mr. Camfield was, in fact, able to develop such a methodology relying on information specific to

FPUC's system.

The company acknowledges that the new methodology isn't perfect but will show that it is the most appropriate methodology for FPUC because it better accounts for FPUC's unique geographic locations and customer demographics. The company believes and will demonstrate that this methodology is more appropriate, reasonable and prudent.

The company shouldn't be required to prove a negative; in other words, show that the prior methodology is not appropriate. In fact, the Commission has never determined that the former methodology is a perfect fit for FPUC, nor has the Commission compelled by past use to defer to that old methodology.

Moreover, this issue, as framed, doesn't ask that you make a specific determination as to whether the prior methodology is less accurate than the proposed methodology. Instead, Issue 3B asks you to determine whether FPUC's proposed methodology is appropriate for FPUC.

FPUC will meet its burden of proof on this issue. Again, neither of the methodologies is a perfect fit, but the use of FPUC-specific data inputs results in the more appropriate methodology being the new one proposed by FPUC. Thank you, Commissioners.

CHAIRMAN GRAHAM: Staff, I have a question. If we address Issues 3B and Issues 22, which are both FPUC, does that clear everything for FPUC?

MS. BENNETT: It does.

CHAIRMAN GRAHAM: Okay. Gentlemen, do you have any statements before we pull the FPUC witness?

MR. REHWINKEL: With respect to FPUC?

CHAIRMAN GRAHAM: Yes.

MR. REHWINKEL: No, sir.

CHAIRMAN GRAHAM: Okay. Ma'am, if you'd call your witness.

MS. KEATING: FPUC calls Cheryl Martin.

CHAIRMAN GRAHAM: I didn't mean to shock you.

Whereupon,

CHERYL M. MARTIN

was called as a witness on behalf Florida Public Utilities Company and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. KEATING:

Q Good morning, Ms. Martin.

A Good morning. Good morning, Commissioners.

Q Would you please state your full name for the record.

A Cheryl M. Martin.

Q And did you cause to be prepared and filed in this proceeding direct testimony on September 8th, 2011?

A Yes, I did.

Q Did you also cause to be prepared and filed Exhibit CMM-1, which has already been marked and included on the Stipulated Exhibit List as Exhibit 30?

A Yes, I did.

Q Do you have you any changes or corrections to your prefiled testimony or exhibit?

A No, I do not.

Q And if I asked you the questions included in your prefiled testimony, would you provide the same answers as you did then?

A Yes, I would.

MS. KEATING: Mr. Chairman, we'd ask that Ms. Martin's testimony be inserted into the record as though read, subject to cross.

CHAIRMAN GRAHAM: We will enter Ms. Martin's record -- prefiled testimony into the record as though read.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110001-EI
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

2012 Projection Testimony of
Cheryl Martin
On Behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. Cheryl Martin, 401 South Dixie Highway, West Palm Beach, FL 33401.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company (FPUC) as the Director of Regulatory Affairs for the Company.

Q. Can you please provide a brief overview of your educational and employment background?

A. I have been employed by FPUC since 1985 and performed numerous accounting and regulatory roles and functions including regulatory accounting (Fuel, PGA, conservation, rate proceedings, Surveillance reports, regulatory reporting), tax accounting, external reports, corporate accounting and Florida accounting. In August 2011 I was promoted to my current position of Director of Regulatory Affairs. I have been an expert witness for numerous proceedings before the Florida Public Service Commission (FPSC). I graduated from Florida State University in 1984 with a BS degree in Accounting. Also, I am a Certified Public Accountant in the state of Florida.

Q. Have you previously testified in this Docket?

A. Yes. I have provided testimony in this proceeding on behalf of Florida Public Utilities on numerous occasions in past years.

Q. What is the purpose of your testimony at this time?

A. I will briefly describe the basis for the computations that were made in the preparation of the various Schedules that we have submitted in support of the January 2012 - December 2012 fuel cost recovery adjustments for our two electric divisions. In addition, I will explain the projected differences between the revenues collected under the levelized fuel adjustment and the purchased power costs allowed in developing the levelized fuel adjustment for the period January 2011 – December 2011 and to establish a "true-up" amount to be collected or refunded during January 2012 - December 2012.

Q. Were the schedules filed by the Company completed under your direction or review?

A. Yes.

Q. Which of the Staff's set of schedules has your company completed and filed?

A. We have filed Schedules E1, E1A, E2, E7, and E10 for the Northwest Division and E1, E1A, E2, E7, E8, and E10 for the Northeast Division. Composite Prehearing Identification Number CMM-1 contains this information.

Q. Did you follow the same procedures that were used in the prior period filings in preparing the projected cost factors for January – December 2012 for both the Northwest and Northeast Divisions?

A. The Company has generally used the same methodology as in prior period filings; however, we have made two changes in the process. First, the Company had, in previous filings, utilized data for the Northeast Division that was obtained from a 2007 Florida Power and Light ("FP&L") Load Research Study to allocate demand costs to the various Northeast Division rate classifications. Similarly, the Company had utilized 2006 Load Research Study data obtained from Gulf Power to allocate demand costs to the various Northwest Division rate classifications. As is further explained herein, the Company has adopted a more representative method for allocating costs to the rate classifications for each Division. The second process change that the Company has incorporated into this filing is the inclusion of the unbilled fuel revenues into the calculation of total fuel revenues and the total true-up amount to be collected/refunded in 2012 for both the Northwest and Northeast Divisions.

<u>Northeast Division – Demand Allocation Method</u>

Q. Please explain the methodology that the Company has used to calculate the Northeast Division levelized fuel adjustment factor?

A. The Company's methodology to calculate the levelized fuel adjustment factor for the Northeast Division is generally the same as in previous filings. The Company obtains cost information from its purchased power supplier and utilizes this information to project the total purchased power costs (energy and demand costs) for 2012. The Company projects other fuel costs related to contract negotiations, fuel consulting work and legal representation outside of costs already embedded in the Company's base rates. The Company also projects the over- or under-recovered amount at the end of 2011. In addition, the Company projects its expected KWH sales to customers in 2012. Based on these projections, the Company has calculated the required levelized fuel adjustment for each rate class that recovers the expected purchased power costs in 2012, as shown in Composite Prehearing Identification Number CMM-1. As has historically occurred, the GSLD1 rate classification is directly assigned its expected purchased power costs.

Q Why does the Company directly assign the GSLD1 rate class purchased power costs?

A. The Company directly assigns the purchased power costs to the GSLD1 rate classification's only two customers because they both have the capability to generate their own power. Both customers only purchase power sporadically from the Company, generally when they have an outage of their power generation facilities. It is not feasible to produce a levelized fuel rate for this rate classification that appropriately allocates costs. Demand and other purchased power costs are assigned to the GSLD1 rate class directly based on their projected CP KW and KWH consumption. This procedure for the GSLD1 class has been in use for several years and has not been changed herein. Costs to be recovered from all other Northeast Division rate classifications are determined after deducting from total purchased power costs those costs directly assigned to GSLD1.

Q. Who does the Company purchase power from for the Northeast Division?

A. The Company purchases power from Jacksonville Electric Authority ("JEA") for the Northeast Division. Effective January 1, 2008, the Company executed an Amended and Restated Electric Service Contract with JEA (the "JEA Contract") which has a term of ten years.

Q. What impact has the JEA Contract had on the Company's levelized fuel rates and customer consumption?

A. Prior to 2008, the Northeast Division had some of the lowest rates in the state, well below the other IOU's in the state. However, the JEA Contract resulted in higher prices that more closely reflect the then-current market conditions and pricing. As a result of higher fuel rates and the down turn in the economy, the Company has experienced significant usage reductions from its customer base. As a result of demand activity unique to the Northeast Division, the Company believes that the previous method of allocating demand costs to rate classifications, which utilized FP&L's 2007 Load Research Data, is no longer the most accurate basis for this purpose.

Q. What basis has the Company used to allocate the JEA demand costs in this filing?

A. The Company has engaged Christensen Associates Energy Consulting ("CA") to develop a Company-based customer usage method on which to allocate demand costs to the various rate classifications. CA has completed this task and has provided a report to the Company. The Company's demand allocation method developed by CA has been utilized in our Projection filing and is shown on Schedule E1 of Composite Prehearing Identification Number CMM-1. The JEA Contract utilizes monthly coincident peaks as the basis for that months demand charge to the Company. Each month of the year has its unique monthly coincident peak which is used for billing purposes. The Company does not have any metering that provides customer-specific data regarding each rate classifications usage during the peak hour that JEA utilizes to determine the monthly demand charge. As such, the CA report concludes that the best indicator of each rate classifications contribution to the coincident peak demand that is currently available is the monthly total KWH usage of each rate classification as a percentage to the monthly total KWH usage for all rate classifications, excluding the GSLD1 rate classification. The Company has utilized the three previous years (2008 through 2010) average data to determine each rate classifications' demand cost allocator. Using a three-year average mitigates the effect of weather and/or other anomalies and provides for a reasonable basis to allocate projected demand costs. This data is more representative of the demand usage by the customers in the Northeast Division and is a better method to allocate the demand costs. All other costs of purchased power will be recovered by the use of the same levelized energy factor for each rate class. Thus the total factor for each rate classification will be the sum of the respective demand cost factor and the levelized energy factor for all other costs.

Q. Is there any additional calculation of cost that is included in the Northeast Division's demand cost recovery factor?

A. Yes. Consistent with the prior year the Company utilizes an allocation of a portion of the transmission demand cost to the Northeast Florida rate classifications. The Company continues to include this calculation in the demand cost recovery factor.

Q. Why is it appropriate to allocate a portion of the transmission costs to the Northeast Division rate classifications?

A. The distribution charge (associated with distribution substations in the Northwest Division) within the fuel charge should be allocated to both divisions in order to offset the disparity in substation related plant cost in the two divisions. This will allow all customers to contribute to the distribution charge within fuel just as all customers contribute to the substation plant related cost included in the base rates. Our Northwest

Division pays for a portion of distribution substations via a distribution charge through the fuel clause, where similar costs in the Northeast Division are paid through base rates since the Company owns the related plant and it is included in rate base. In the Northwest Division, Gulf Power Company owns the distribution substation with the exception of the distribution feeder bus. To allow for fair recovery of these costs the fuel portion should be allocated between the two divisions, similar to the rate base portion included for recovery in base rates. This allows for equitable cost distribution and recovery between all rate classifications.

Q. What is the appropriate total distribution charge allocated to the Northeast Division rate classifications for the 2012 calendar year?

A. The appropriate total distribution charge allocated to the Northeast Division rate classifications for the 2012 calendar year is $476,832.

Q. What was the basis of the allocation used to allocate a portion of the distribution charge to Northeast Division rate classifications?

A. One half of the distribution charge will be included within the Northeast Division demand cost recovery factor just as the substation plant cost was equally allocated to all rate classifications within base rates.

<u>Northwest Division – Demand Allocation Method</u>

Q. Please explain the methodology that the Company has used to calculate the Northwest Division levelized fuel adjustment factor?

A. The Company's methodology to calculate the levelized fuel adjustment factor for the Northwest Division is generally the same as in previous filings. The Company obtains cost information from its purchased power supplier and utilizes this information to project the total purchased power costs (energy and demand costs) for 2012. The Company also projects the over- or under-recovered amount at the end of 2011. The Company projects other fuel costs related to contract negotiations, fuel consulting work and legal representation outside of costs already embedded in the Company's base rates. In addition, the Company projects its expected KWH sales to customers in 2012. Based on these projections, the Company has calculated the required levelized fuel adjustment for each rate class that recovers the expected purchased power costs in 2012, as shown in Composite Prehearing Identification Number CMM-1.

Q. Who does the Company purchase power from for the Northwest Division?

A. The Company purchases power from Gulf Power Company ("Gulf Power") for the Northwest Division. Effective January 1, 2008, the Company executed an Agreement for Generation Services Between Gulf Power Company and Florida Public Utilities Company with Gulf Power (the "Gulf Power Contract") which has a term of ten years. On January 25, 2011, the Company entered into Amendment No. 1 to the Gulf Power Contract, which, among other things, extended the Gulf Power Contract for two additional years.

Q. What impact has the Gulf Power Contract had on the Company's levelized fuel rates and customer consumption?

A. Prior to 2008, the Northwest Division had some of the lowest rates in the state, well below the other IOU's in the state. However, the Gulf Power Contract resulted in higher prices that more closely reflect the then-current market conditions and pricing. As a result of higher fuel rates and the down turn in the economy, the Company has experienced significant usage reductions from its customer base. As a result of demand activity unique to the Northwest Division, the Company believes that the previous method of allocating demand costs to rate classifications, which utilized Gulf Power's 2006 Load Research Data, is no longer the most reasonable basis for this purpose.

Q. What basis has the Company used to allocate the Gulf Power demand costs in this filing?

A. The Company has engaged Christensen Associates Energy Consulting ("CA") to develop a Company-based customer usage method on which to allocate demand costs to the various rate classifications. CA has completed this task and has provided a report to the Company. The Company's demand allocation method developed by CA has been utilized in our Projection filing and is shown on Schedule E1 of Composite Prehearing Identification Number CMM-1. The Gulf Power Contract utilizes five summer months (May through September) to determine the maximum coincident peak used in the calculation of the following years' demand charge calculation. The Company does not have any metering that provides customer-specific data regarding each rate classifications usage during the maximum peak hour that Gulf Power determines during the May through September period. As such, the CA report concludes that the best indicator of each rate classifications contribution to the coincident peak demand that is currently available is the monthly total KWH usage for the May through September period of each rate classification as a percentage to the monthly total KWH usage for all rate classifications for the same five month period. The Company has utilized the three previous years (2008 through 2010) average data to determine each rate classifications' demand cost allocator. Using a three-year average mitigates the effect of weather and/or other anomalies and provides for a reasonable basis to allocate projected demand costs. This data is more representative of the demand usage by the customers in the Northwest Division and is a better method to allocate the demand costs. All other costs of purchased power will be recovered by the use of the same levelized energy factor for each rate classification. Thus the total factor for each rate classification will be the sum of the respective demand cost factor and the levelized energy factor for all other costs.

Q. Is there any additional calculation of cost that is included in the Northwest Division's demand cost recovery factor?

A. No.

Unbilled Fuel Revenues

Q. Has the Company, in previous filings, included unbilled fuel revenues in the levelized fuel adjustment calculation?

A. No. Prior to the merger with Chesapeake Utilities Company on October 29, 2009, the Company did not record an entry for unbilled revenues for fuel.

Q. Why did the Company include unbilled fuel revenues in the over- and under-recovery amounts for the 2011 Actual/Estimated True-Up to be refunded in 2012?

A. The computation of those amounts in the 2011 Actual/Estimated True-Up filing, included the aforementioned unbilled fuel revenue components based on the balances that were computed on our books and footnoted within Schedule A-2, page 3 of our monthly Fuel schedule for July 2011 in the Northwest Division and for June 2011 in the Northeast Division. These amounts are also projected to remain the same as of December 2011. The Company estimates accumulated unbilled fuel revenues of $1,743,732 for the Northwest Division and $1,686,902 for the Northeast Division. These amounts are included as additional over-recoveries to our 2011 True-Up balances.

Q. Why is it appropriate to include unbilled fuel revenues in the over- and under-recovery?

A. The over- and under-recovery of fuel is based on actual fuel costs and fuel revenues. Fuel costs are normally based on a calendar month period, while fuel revenues are based on cycle billing and historically excluded the consumption of fuel revenues for the entire calendar month. Unbilled fuel revenues reflect the difference between what has been billed for that calendar month, and what remains to be billed through the calendar month end. This accounting treatment is appropriate for GAAP purposes and is included in the Company's accounting records. It is also appropriate to match the fuel costs with the applicable fuel revenues and the same period of time should be used for purposes of computing any over- and under-recovery of fuel costs.

Q. Will customers benefit from including unbilled fuel revenues in the over and under recovery of fuel costs in 2011?

A. Yes, If the unbilled fuel revenues is not recognized in the net over/under recovery, the Company will recognize a under recovery for the fuel revenues not yet billed (unbilled fuel revenues). The Company feels it is appropriate for the customers to receive the benefit for the fuel revenues embedded in unbilled revenues since they have been required to pay for the fuel costs for the entire month.

Q. What impact will this recognition of unbilled fuel revenues have on the net over/under recoveries in the current and future periods?

A. In the initial period that unbilled fuel revenues are recognized for the fuel clause, customers will obtain a benefit through a reduced under recovery. In future periods, without weather or significant growth, the change in unbilled fuel revenues will not be significant. The benefit is achieved primarily in the initial period of recognition, but this is a permanent savings to the customers.

Summary Rates

Q. What are the final remaining true-up amounts for the period January – December 2010 for both Divisions?

A. In the Northwest Division, the final remaining true-up amount was an over-recovery of $885,786. The final remaining amount for the Northeast Division was an over-recovery of $856,166.

Q. What are the estimated true-up amounts for the period of January – December 2011?

A. In the Northwest Division, there is an estimated over-recovery of $682,002. The Northeast Division has an estimated over-recovery of $2,292,856.

Q. Please address the calculation of the total true-up amount to be collected or refunded during the January - December 2012 year?

A. The Company has determined that at the end of December 2011 based on six months actual and six months estimated. We will have over-recovered $1,567,788 in purchased power costs in our Northwest Division. Based on estimated sales for the period January - December

2012, it will be necessary to subtract .48272¢ per KWH to refund this over-recovery. In our Northeast division we will have over-recovered $3,149,022 in purchased power costs. This amount will be refunded at .95005¢ per KWH during the January - December 2012 period (excludes GSLD1 customers). Page 3 and 10 of Composite Prehearing Identification Number CMM-1 provides detailed calculations of the respective true-up amounts.

Q. What will the total fuel adjustment factor, excluding demand cost recovery, be for both divisions for the period?

A. In the Northwest Division the total fuel adjustment factor as shown on Line 33, Schedule E-1 is 6.544¢ per KWH. In the Northeast Division the total fuel adjustment factor for "other classes", as shown on Line 43, Schedule E-1, is 5.961¢ per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January - December 2012 including base rates, conservation cost recovery factors, gross receipts tax and fuel adjustment factor and after application of a line loss multiplier.

A. As shown on Schedule E-10 in Composite Prehearing Identification Number CMM-1, a residential customer in the Northwest Division using 1,000 KWH will pay $133.19, a decrease of $4.34 from the previous period. In the Northeast Division a residential customer using 1,000 KWH will pay $125.10, a decrease of $7.23 from the previous period.

Q. Has the Company adjusted the TOU rates for the 2012 period?

A. Yes, the Company has filed updated TOU rates for the Northwest Division. As of August 2011, the Company has five residential customers and one general service demand customer on TOU rates. The Company has updated rates for this tariff based on the revised projections of fuel costs for the 2012 period. The TOU rates continue to provide benefit to other customers by reduced demand costs. The methodology to compute the TOU fuel rates remains consistent with the methodology for 2011 rates; but rates have been updated to reflect the most recent fuel costs to remaining customers in the Northwest division. See Schedule E1, page 2 for a summary of the revised TOU rates by rate class.

Q. Does this conclude your testimony?

A. Yes.

BY MS. KEATING:

Q And, Ms. Martin, have you also prepared a brief summary of your testimony?

A Yes, I have.

Q And if you would, please give it at this time.

A As you know, Florida Public Utilities has two separate divisions, one in Fernandina Beach and one in Marianna. My projection testimony addressed the computations and schedules that we used to develop the company's fuel cost recovery adjustments and the 2012 fuel factors for these two distinct operating divisions.

My summary, will, however, focus on one key aspect of my testimony that remains in dispute, that being the new demand cost allocation methodology that FPU wants to use. As you know, FPU's electric divisions are small and both are located in relatively non-urban areas of North Florida. FPU doesn't have its own generation, and thus purchases all of its power from other providers.

We also don't have the costly equipment installed that would enable the company to gather more detailed customer demand data. Likewise, because of our small size, the company does not have to file load research studies like other IOUs, as Staff has noted in its position.

Nonetheless, over the years FPUC has had to rely on demand data obtained from other utilities, namely FP&L and Gulf, to allocate demand. This year, however, after reviewing the demand activity across both divisions, including significant usage reductions in segments of the company's customer base, the company decided to engage Christensen and Associates, specifically Robert Camfield, to study whether it was possible to develop an FPUC-specific methodology to allocate demand costs, one that did not rely on demand information from other utility systems that are not really comparable to FPUC.

Mr. Camfield was, in fact, able to develop a methodology that the company believes allocates demand costs in a manner that better represents what actually occurs on FPU's system. The new methodology places greater emphasis on one of the factors that's also a component of the prior methodology, kWh usage on FPU's system. An added benefit of the new methodology is that FPUC's residential customers in both divisions will see lower rates under our proposed method versus using the load data of other utilities.

While I don't claim to be an expert in allocation methodology, based on my knowledge and experience in the industry and my 26 years with this company specifically, I believe that Mr. Camfield's recommendation that the company use class-specific energy sales to allocate demand makes sense.

I'll be the first to admit that there's not an exact correlation between usage and demand, and thus this methodology is by no means perfect, but kWh is a clear indicator of the changes in demand and, as I mentioned, it's a component of the prior methodology. Likewise, there is a correlation between energy sales and peak demand.

Also, as far as I'm aware, the Commission has never concluded that the prior methodology is a perfect fit for FPUC, particularly in this context, although it is the historical method used. An absence of load research data specific to the company, and in light of Mr. Camfield's expertise in this area, the company strongly believes that this new methodology is the best and most appropriate method for allocating demand costs among FPU's customer classes. It better recognizes the unique nature, both geographical and economically, of FPUC and its customer base. Thus, the company asks that the Commission allow the company to continue to use our proposed method. This concludes my summary.

MS. KEATING: Ms. Martin is available for cross.

CHAIRMAN GRAHAM: All right. Intervenors, who wants to be first?

MR. REHWINKEL: No questions.

MR. MOYLE: No questions.

CHAIRMAN GRAHAM: Staff?

CROSS EXAMINATION

BY MS. BARRERA:

Q Yes. Ms. Martin, I'm going to refer to the transcript of your deposition, which would be Exhibit 60.

A Okay.

Q On Page 12 of your deposition, Bate stamp 00243, you stated that the load data FPUC historically used was based on another company's load, and it is your opinion that it's not necessarily reflective of FPUC's customer load.

Have you done any studies or analysis to determine any differences in customer load between FPUC and FP&L or between FPUC and Gulf Power Company?

A No, we have not. However, just taking a look at FP&L and Gulf Power's load, a little bit of a unique situation is that those two companies do not have the same customer makeup, they don't have the same customer locations, the same makeup in terms of who might be incorporated into which class.

And I also took a look at using FPL or using Gulf's load data. If you used FPL's in the Marianna division, you would get different results. And so just taking a look at, at that type of data would, would put you -- you know, you would call into question why would it be appropriate to use another company's load data to try to mirror what your company's load data was?

Q You also stated that cities, and you just referred to it, that cities served by Gulf such as Destin and Panama City have a much different makeup in terms of customer and usage patterns than Marianna, which is a more rural type of town. Would you agree, however, that Gulf Power Company's service territory also covers rural areas?

A Well, first of all, I don't believe I specifically said that Destin or Panama City was in Gulf's territory. I was merely trying to point out that larger utility companies serve much different type of a customer mix than our small company where we're specifically -- primarily have customers that are in small rural towns.

FP&L and Gulf Power have a much larger customer base and are spread out much, over much more of the State of Florida, and they incorporate much larger cities, and cities like Destin or Panama City would have a much different makeup than a small town like Marianna. So I was trying to really explain that, you know, it was very hard to use companies that contain a much different makeup in terms of customer mix and economics than our small company that only is in rural type areas in Marianna.

Q Were you able to determine or differentiate between cities, the load in cities such as Panama City or Destin, the larger cities, and the load in the rural areas served by Gulf?

A No. We did not do any detailed research on their load data. We also are not able to provide any type of research by customer class of our demand or our load research data. We don't have the equipment that's necessary to be able to obtain that information.

I don't believe anybody has ever studied to see whether or not the Gulf Power or the FP&L load data would be applicable to FPUC, nothing that I'm ever aware of. But I do know that there are significant reasons why it would not be appropriate.

Q Did you compare FP&L and Gulf's tariff to FPUC's tariff to determine if there are any differences in the definition of a residential or GS or GSLD customer?

A No, I did not.

Q Do you have any analytical support to back the statement that there is a correlation between energy sales and the peak demand?

A Well, I believe that there is some supporting evidence with respect to taking a look at the kWh usage and how that has dropped over the years. So, indeed, there would be a correlation in the demand that was associated with the usage as well. I mean, many of our exhibits and many of our testimony support that analysis, so I'm not sure specifically what you're asking.

Q That's answered.

Referring to page 9 in your deposition, you stated that with the new contracts that were closer to market, FPUC's customers experienced a dramatic price increase, and as a result you believe customers experienced significant usage decreases. Have you looked into FP&L's or Gulf's historical consumption pattern to see if FP&L and/or Gulf experienced similar consumption trends as FPUC?

A No, I have not look into FP&L or Gulf's, but I have looked into the facts facing our company. And I know that from prior to 2008 both customers in the Gulf -- I mean, in Fernandina and Marianna had prices that were well below market price, and we offered supporting documents with respect to that information.

But if you take a look at the price increases that faced our customers, they had almost a two-fold increase in their fuel rates prior to 2008 and post-2008. That dramatic price increase that faced our customers definitely had an impact on their usage, and also, in our opinion, definitely impacted the demand and decreased the demand by our customers.

Q During your deposition we discussed how FPUC's proposed allocation methodology impacts the bills of the various rate classes, and you also provided rate comparisons in Exhibit 1 to the deposition, Bate stamp 00269.

How are the different customer classes impacted by the proposed allocation method when compared to using the load research data from FP&L and Gulf?

A In both our northwest and our northeast divisions, under the method that we filed and proposed, the residential customers would, would all have a lower fuel bill than under the method, the old method.

In our northwest division, the GS customers would also have a lower fuel bill than under the old method. In the northeast Florida, the general service would have a slightly higher fuel bill, as well as the remaining commercial and industrial classes.

MS. BARRERA: One second.

(Pause.)

BY MS. BARRERA:

Q Can you estimate for us today what a thousand-kilowatt residential bill under either method would look like for the consumers?

A Yes. I believe we provided that as an exhibit. Schedule E10 shows a residential typical bill with a thousand kWh. Under our proposed method, in the northwest division a residential bill would be $133.19 per thousand kWh. And in Fernandina Beach or the northeast division, the residential typical bill would be $125.10. And that was under FPUC proposed method.

Under the old methodology, a residential customer in our northwest division would have a typical bill of $139.28 per thousand kWh, and for northeast a residential customer would have a typical bill of 129.07 per 1,000 kWh.

MS. BARRERA: Thank you. I have no more questions.

CHAIRMAN GRAHAM: Commission, any questions of this witness?

Staff?

MS. BENNETT: FPUC asked that I hand out an exhibit while the witness was being cross-examined, and it would be Exhibit 88, I believe.

MS. KEATING: I think it will be marked at this point as Exhibit 88. But if, if I might have the liberty, Mr. Chairman, we have just a couple of real short redirect for Ms. Martin, if that's your will.

CHAIRMAN GRAHAM: Well, let's mark this exhibit as 88, since I have it sitting right here in front of me. And what's a short title for this thing?

MS. KEATING: FPUC's response to request for production of documents number 1.

(Exhibit 88 marked for identification.)

CHAIRMAN GRAHAM: Okay.

MS. KEATING: Thank you, Mr. Chairman.

CHAIRMAN GRAHAM: Yes.

REDIRECT EXAMINATION

BY MS. KEATING:

Q Ms. Martin, Staff asked you several questions as to whether you had done comparisons of FPL load data and Gulf load data. Let me ask you this, how many customers does FPUC have on its system in total?

A FPUC in total, the electric customers are 31,000.

Q And for the northwest division?

A 15,172.

Q And I believe you've mentioned Marianna as one of the municipalities in that northwest division. Can you name some of the other towns that are in that area, in that division?

A Bristol and --

Q How about the northeast division, how many customers are in that division?

A 15,829.

Q And what are some of the municipalities in that division?

A Fernandina Beach.

Q Could you -- do you have knowledge of the geographic areas that FPL serves in?

A I do not.

Q And would your answer be the same for Gulf?

A Correct.

Q Staff asked, also asked you a question about the impacts of this new methodology on the different rate classes. Do you believe -- is it your understanding this new methodology shifts costs to customers or rate classes unfairly such that classes that aren't creating demand are now responsible for costs they have not caused?

A No, I do not. I believe that the methodology that we propose is appropriate and is the most appropriate methodology that we have and most fairly allocates the cost to our customers and our customer classes.

MS. KEATING: Thank you, Mr. Chairman. That's all the redirect we have.

CHAIRMAN GRAHAM: All right. And this is your only witness; is that correct?

MS. KEATING: It is.

CHAIRMAN GRAHAM: Okay. Thank you, Ms. Martin.

THE WITNESS: Thank you, Commissioners.

MS. KEATING: And, Mr. Chairman, if it's appropriate at this time, we'd move entry into the record of Exhibit Number 30 and Number 88.

CHAIRMAN GRAHAM: If there's no objection, we're going to move Exhibits 30 and 88 into the record. Seeing none.

(Exhibits 30 and 88 admitted into the record.)

MS. KEATING: And, Mr. Chairman, may Ms. Martin be excused?

CHAIRMAN GRAHAM: Staff, any further questions for Ms. Martin?

MS. BENNETT: We have no further questions for Ms. Martin. The only thing remaining would be a bench decision by -- or a decision by the Commission, either bench decision or the briefing and agenda conference. I don't know if you want to do that now or at the end of the 01 docket.

CHAIRMAN GRAHAM: Commissioners?

MS. KEATING: Mr. Chairman, if I may.

CHAIRMAN GRAHAM: Yes.

MS. KEATING: We'd respectfully request the opportunity to either present closing statements on this issue, if you would like to take a bench decision on it, or we'd actually prefer to provide a post-hearing brief on this issue.

CHAIRMAN GRAHAM: Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

I would support that request and ask for the opportunity to review a post-hearing brief on the issue.

CHAIRMAN GRAHAM: Okay. Sounds good to me. So, Staff, that being the case, then we can just release this, this witness and we're done at this point with --

MS. BENNETT: That is correct. We would be done with FPUC's witness and counsel. The -- we're requesting daily transcripts. Briefs will be due on November the 8th. And we -- Staff will present a recommendation to you at your November 22nd agenda conference.

CHAIRMAN GRAHAM: Sounds good.

MS. KEATING: Thank you, Mr. Chairman, Commissioners.

CHAIRMAN GRAHAM: Thank you very much.

All right. We've got about a quarter 'til 12:00. I think this is just as good a time as any to break for lunch. Let's reconvene at quarter after 1:00.

(Recess taken.)

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

I, LINDA BOLES, RPR, CRR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

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

DATED THIS 2nd day of November, 2011.

Linda Boles

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