BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR. — DOCKET NO. 060001-EI

PETITION TO RECOVER NATURAL GAS STORAGE PROJECT COSTS THROUGH FUEL COST RECOVERY CLAUSE, BY FLORIDA POWER & LIGHT COMPANY. — DOCKET NO. 060362-EI

PETITION FOR AUTHORITY TO RECOVER PRUDENTLY INCURRED STORM RESTORATION COSTS RELATED TO 2004 STORM SEASON THAT EXCEED STORM RESERVE BALANCE, BY FLORIDA POWER & LIGHT COMPANY. — DOCKET NO. 041291-EI

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VOLUME 3

Pages 407 through 561

PROCEEDINGS: HEARING

BEFORE: CHAIRMAN LISA POLAK EDGAR
COMMISSIONER J. TERRY DEASON
COMMISSIONER ISILIO ARRIAGA
COMMISSIONER MATTHEW M. CARTER, II
COMMISSIONER KATRINA J. TEW

DATE: Tuesday, November 7, 2006

TIME: Commenced at 9:35 a.m.

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

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

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
30	JP-1T	413	480
31	JP-2T	413	480
32	JP-3T	413	480
33	JP-1R	413	480
34	JP-1P	413	480
35	PRM-1	482	482
36	PRM-2	482	482
37	PRM-1T	482	482
38	PRM-2T	482	482
39	JM-1P	482	482
40	RMO-1T	499	499
49	JTW-1	505	547
56	JTW-2	505	547

P R O C E E D I N G S

(Transcript follows in sequence from Volume 2.)

CHAIRMAN EDGAR: Good morning. We will go back on the record and begin our work again this morning.

Ms. Bennett, any preliminary matters before we move into calling the next witness?

MS. BENNETT: I believe Doc Horton has a preliminary matter.

CHAIRMAN EDGAR: Mr. Horton.

MR. HORTON: Yes. Madam Chairman, just for some clarification, with respect to Issue 8, the fuel cost recovery factors for the rate classifications, on Page 15 of the prehearing order Florida Public Utilities' factors are shown.

The factors for Fernandina Beach were revised as a result of the revised exhibit that was sponsored by Ms. Martin yesterday afternoon and entered into the record as Exhibit 22. So the correct factors for Fernandina Beach are reflected in that revised exhibit. I just wanted to make sure that was clear. Thank you.

CHAIRMAN EDGAR: Okay. Thank you for that clarification for the record.

Ms. Bennett, any other matters?

MS. BENNETT: I believe we're ready for the next witness.

CHAIRMAN EDGAR: Okay. Mr. Burnett.

MR. BURNETT: Thank you. Good morning, Commissioners. We would call Javier Portuondo.

May I proceed, Madam Chairman? Thank you.

JAVIER PORTUONDO

was called as a witness on behalf of Progress Energy Florida and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BURNETT:

Q Good morning, sir. Will you please introduce yourself to the Commission and provide your business address.

A My name is Javier Portuondo. My business address is 410 South Wilmington Street, Raleigh, North Carolina.

Q Mr. Portuondo, have you already been sworn as a witness?

A Yes, I have.

Q And who do you work for, sir, and what is your position?

A My position is Director of Regulatory Planning, and I work for Progress Energy Service Company.

Q Mr. Portuondo, have you filed prefiled direct testimony and exhibits in this proceeding?

A Yes, I have.

Q And do you have that in front of you now?

A Yes, I do.

Q Do you have any changes to make to your prefiled testimony and exhibits?

A No, I do not.

Q If I asked you the same questions in your prefiled testimony today, would you give the same answers that you -- that are in your prefiled testimony?

A Yes, I would.

MR. BURNETT: Madam Chairman, at this time may I note that, for the record that Mr. Portuondo's exhibits have been marked as Exhibits 30 through 34 for identification.

CHAIRMAN EDGAR: So noted.

(Exhibits 30 through 34 marked for identification.)

MR. BURNETT: Madam Chairman, at this time we request that the prefiled testimony of Mr. Portuondo and the exhibits be entered into the record as if it were read today.

CHAIRMAN EDGAR: The prefiled testimony will be entered into the record as though read.

MR. BURNETT: Thank you. We tender Mr. Portuondo for cross-examination.

PROGRESS ENERGY FLORIDA

DOCKET NO. 060001-EI

Fuel and Capacity Cost Recovery
Final True-Up for the Period
January through December, 2005

DIRECT TESTIMONY OF
JAVIER PORTUONDO

March 1, 2006

Q. Please state your name and business address.

A. My name is Javier Portuondo. My business address is P.O. Box 14042, St. Petersburg, Florida 33733.

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

A. I am employed by Progress Energy Service Company, LLC as Director of Regulatory Planning.

Q. Have your duties and responsibilities changed since you last testified in this proceeding?

A. Yes. I am now responsible for regulatory planning, cost recovery and pricing functions for both Progress Energy Florida (PEF or Company) and Progress Energy Carolinas.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe PEF's Fuel Adjustment Clause final true-up amount for the period of January through December 2005, and

PEF's Capacity Cost Recovery Clause final true-up amount for the same period.

Q. Have you prepared exhibits to your testimony?

A. Yes, I have prepared and attached to my true-up testimony as Exhibit No. __ (JP-1T), a Fuel Adjustment Clause true-up calculation and related schedules, Exhibit No. __ (JP-2T), a Capacity Cost Recovery Clause true-up calculation and related schedules, and Exhibit No. __(JP3-T), Schedules A1 through A9 and A12 for December 2005, year-to-date.

Q. What is the source of the data that you will present by way of testimony or exhibits in this proceeding?

A. Unless otherwise indicated, the actual data is taken from the books and records of the Company. 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. Would you please summarize your testimony?

A. Per Order No. PSC-05-1252-FOF-EI, the projected 2005 fuel adjustment true-up amount was an under-recovery of $315,692,056. The actual under-recovery for 2005 was $316,077,111 resulting in a final fuel adjustment true-up under-recovery amount of $385,055 (Exhibit No. __ (JP-1T)).

The projected 2005 capacity cost recovery true-up amount was an under-recovery of $11,616,464. The actual amount for 2005 was an under-recovery of $12,197,740 resulting in a final capacity true-up under-recovery amount of $581,276 (Exhibit No. __ (JP-2T)).

FUEL COST RECOVERY

Q. What is PEF's jurisdictional ending balance as of December 31, 2005 for fuel cost recovery?

A. The actual ending balance as of December 31, 2005 for true-up purposes is an under-recovery of $316,077,111.

Q. How does this amount compare to PEF's estimated 2005 ending balance included in the Company's projections for the calendar year 2005?

A. The actual true-up attributable to the January - December 2005 period is an under-recovery of $316,077,111 which is $385,055 higher than the re-projected year end under-recovery balance of $315,692,056.

Q. How was the final true-up ending balance determined?

A. The amount was determined in the manner set forth on Schedule A2 of the Commission's standard forms previously submitted by the Company on a monthly basis.

Q. What factors contributed to the period-ending jurisdictional under-recovery of $316,077,111 shown on your Exhibit No. __ (JP-1T)?

A. The factors contributing to the under-recovery are summarized on Exhibit No. __ (JP-1T), sheet 1 of 7. Net jurisdictional fuel revenues fell below the forecast by $62.8 million, while jurisdictional fuel and purchased power expense increased $169.1 million. This $169.1 million unfavorable variance is primarily attributable to escalating fuel costs throughout the year which not only impacted PEF's generation expenses but also the cost of power purchases. The $316.1 million also includes the deferral of $79.2 million of 2004 under-recovery approved in Order No. PSC-04-1276-FOF-EI. By combining the differences in jurisdictional revenues and jurisdictional fuel expenses, and the 2004 deferral, the net result is an under-recovery of $311.1 million related to the January through December 2005 true-up period. When interest of $5.0 million is included, the actual ending under-recovery balance is $316.1 million as of December 31, 2005.

Q. Please explain the components shown on Exhibit No. __ (JP-1T), sheet 4 of 7 which produced the $208.4 million unfavorable system

variance from the projected cost of fuel and net purchased power transactions.

A. Sheet 4 of 7 is an analysis of the system variance for each energy source in terms of three interrelated components; (1) changes in the amount (MWH's) of energy required; (2) changes in the heat rate, or efficiency, of generated energy (BTU's per KWH); and (3) changes in the unit price of either fuel consumed for generation ($ per million BTU) or energy purchases and sales (cents per KWH).

Q. What effect did these components have on the system fuel and net power variance for the true-up period?

A. As shown on sheet 4 of 7, the dollar variance due to MWHs generated and purchased produced a cost decrease of $11.6 million. The primary reason for this favorable variance was lower system requirements.

The unfavorable heat rate variance (column C) of $11.7 million is primarily due to generation mix.

The unfavorable price variance of $208.3 million (column D) was caused by price increases of most system resources. Coal prices were higher than estimated mainly due to higher commodity prices and rail freight costs in 2005 contracts. Actual natural gas and light oil prices continue to surge over projections due to limited excess production and refining capacity. To mitigate some of this price risk and volatility, PEF entered into hedging contracts. Increases in fuel prices also contributed to higher amounts paid for power purchases. In addition, escalating coal prices resulted in higher energy payments to qualifying facilities (QF) since nearly all the contracts are tied to coal unit pricing.

Q. Does this period ending true-up balance include any noteworthy adjustments to fuel expense?

A. Yes. Noteworthy adjustments are shown on Exhibit No. __ (JP-3T) in the footnote to line 6b on page 1 of 2, Schedule A2. These adjustments include interest associated with inadvertent overpayments to QFs and a FERC Compliance Audit refund. A deduction for principal associated with the overpayments to QFs is reflected in the year-to-date under-recovery reported on line 11, page 2 of 2, of Schedule A1 (Exhibit No. __ (JP-3T). Also included in the footnote to line 6b on page 1 of 2, Schedule A2, is depreciation and return associated with Hines Unit 2 as authorized in Order No. PSC-02-0655-AS-EI.

Q. What was the total amount of overpayments made to PEF's Qualifying Facilities?

A: PEF inadvertently overpaid $6.1 million to QF's from August 2003 through August 2004. This amount does not include $143,518 of cumulative interest from August 2003 to May 2005 due retail ratepayers for the overpayments.

Q: When was this amount refunded to PEF's retail ratepayers?

A: PEF deducted the $6.1 million principal and $143,518 cumulative interest amount from its retail fuel cost under-recovery in May 2005. This reduction is reflected in the $316.1 under-recovered fuel balance at year-end 2005.

Q. What was the total amount of the FERC Compliance Audit refund and how was this amount allocated between Progress Energy Carolinas and PEF?

A. The total refund resulting from the FERC Compliance Audit was $5.5 million. This amount was allocated based on 2004 MWH sales. This methodology resulted in $2.4, $.5 and $2.6 million allocated to North Carolina, South Carolina and Florida, respectively.

Q. When did PEF refund the $2.6 million to its retail ratepayers?

A. PEF deducted $2.6 million from its retail fuel cost under-recovery in May 2005. This amount is reflected in the $316.1 million under-recovered fuel balance at year-end 2005.

Q. Did PEF's customers benefit during the true-up period from its investment in Hines Unit 2 previously approved by the Commission?

A. Yes. Actual 2005 system fuel savings for Hines Unit 2 was $131,515,173. Total system depreciation and return was $41,558,153. This results in a net system benefit to customers of $89,957,020 (Exhibit No. __ (JP-1T), sheet 7 of 7).

Q: What was the cumulative net system benefit to customers from PEF's investment in Hines Unit 2 from its in-service date through December 31, 2005?

A: Total system fuel savings for Hines Unit 2 from December 2003 through December 2005 was $181,575,260. Total system depreciation and return for this period was $83,723,818 resulting in a cumulative net system benefit to customers of $97,851,442 (Exhibit No. __ (JP-1T), sheet 7 of 7).

Q. Does the final true-up ending balance contain any incremental costs related to storm events during the 2005 hurricane season?

A. Yes. The final true-up ending balance includes $48,152,742 in incremental costs related to the 2005 storm season.

Approximately $1.1 million of incremental coal costs were incurred for diversions of both domestic barges and foreign vessels to alternate terminals as a result of limited operations and *force majeure* measures invoked by International Marine Terminal (IMT) due to Hurricanes Katrina and Rita. The diversions of coal barges and vessels spanned nearly 3 ½ months as IMT struggled to regain normal operations. PEF used Tampaplex, IC Rail Marine Terminals and Mobile River Terminals as alternate facilities to unload and reload foreign coal deliveries into gulf barges for delivery to Crystal River. PEF used Associated Terminals to perform midstream transfers of river barges to cross-gulf barges in order to maintain deliveries of domestic coal supplies. PEF believes that it prudently incurred the $1.1 million in incremental coal costs in order to maintain inventory levels and avoid disruptions in coal plant operations. No incremental fuel costs were incurred for rail shipments of coal to Crystal River as the hurricanes did not impact CSX operations.

Approximately $47.1 million of incremental costs were incurred for natural gas and No. 6 fuel oil. These incremental fuel costs are explained further in the direct testimony of Pamela R. Murphy.

Q. Has the three-year rolling average gain on economy sales included in the Company's filing for the November, 2005 hearings been updated to incorporate actual data for all of year 2005?

A. Yes. PEF has calculated its three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2003 through 2005, as follows:

Year	Actual Gain
2003	$ 9,844,761
2004	5,330,652
2005	1,703,378
Three-Year Average	$ 5,626,264

Q. Order No. PSC-02-1484-FOF-EI, issued in Docket No. 011605-EI, requires each utility to include in the final true-up each year all base year and recovery year operating and maintenance expenses associated with financial and physical hedging activities. What were the base year and recovery year O&M expenses associated with hedging?

A. There were no base O&M expenses associated with hedging activities; however, incremental O&M expenses incurred in 2005 attributable to net new personnel assigned to physical and financial hedging were $50,618 (Schedule A2, page 1 of 2, footnote to line 6b).

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 2005 for capacity cost recovery?

A. The actual ending balance as of December 31, 2005 for true-up purposes is an under-recovery of $12,197,740.

Q. How does this amount compare to the estimated 2005 ending balance included in the Company's projections for calendar year 2005?

A. When the estimated 2005 under-recovery of $11,616,464 is compared to the $12,197,740 actual under-recovery, the final net true-up attributable to the twelve month period ended December 2005 is an under-recovery of $581,276.

Q. Is this true-up calculation consistent with the true-up methodology used for the other cost recovery clauses?

A. Yes. The calculation of the final net true-up amount follows the procedures established by the Commission.

Q. What factors contributed to the actual period-end capacity under-recovery of $12.2 million?

A. Exhibit No. __ (JP-2T, sheet 1 of 3) compares actual results to the original projection for the period. Actual jurisdictional revenues were $11.5 million lower than projected revenues due to lower retail sales. Actual jurisdictional capacity expenses were $.5 million higher than projected for various reasons. A $1.4 million increase in capacity expenses resulted from CP&Lime purchases that were not included in the original forecast. A

$4.0 million increase in capacity expenses was due to additional Southern Company UPS costs specified in the contract. These increases were offset by a $5.7 million reduction in capacity expenses due to some QF's not meeting capacity commitments as specified in their contracts, and a $5.9 million reduction in capacity expenses that resulted from the cancellation of a summer peaking purchase due to transmission constraints. Offsetting the lower capacity payments were additional incremental security expenses of $3.8 million mainly due to carry over of 2004 Maritime Transportation Security Act projects to 2005, and, $1.8 million of lower transmission revenues due to lower economy sales. An interest provision of $.2 million also contributed to the total under-recovery of capacity expenses.

Q. Were there any items of note included in the current true-up period?

A. Yes. In Order No. PSC-02-1761-FOF-EI, issued in Docket No. 020001-EI, the Commission addressed the recovery of incremental security costs through the capacity cost recovery clause. Exhibit No. __ (JP-2T, sheet 2 of 3) includes incremental security costs of $6,124,772 (system).

OTHER ISSUES

Q. Has PEF confirmed the validity of the methodology used to determine the equity component of Progress Fuels Corporation's (PFC) capital structure for calendar years 2004 and 2005?

A. Progress Energy's Audit Services department reviewed the 2004 annual comparison of PFC's revenue requirements under full regulatory treatment to revenue requirements using an equity amount of 55% of net long-term assets (short cut method). The Commission issued Order 92-0347 which requires this comparison to be performed annually. The analysis showed that for 2004, the short cut method resulted in revenue requirements which were $86,047 or .026% higher than revenue requirements under the full regulatory calculation. This analysis confirms the appropriateness and continued validity of the short cut method. We believe the methodology used to determine the equity component of PFC's capital structure for 2005 has been properly applied; however, an audit to validate the calculation is not scheduled for completion by Audit Services until the end of the 1st quarter of 2006.

Q: How did PEF recover 2005 Waterborne Coal Transportation Services (WCTS) costs pending the Commission's review of the new WCTS contracts?

A: If new WCTS contracts were not approved by January 1, 2005, the Stipulation and Settlement in Docket No. 031057-EI specified continued use of the 2004 settlement rates until Commission approval of these contracts or market proxies. However, PFC billed PEF at actual WCTS rates, which were lower than the 2004 settlement rates. It was in the best interest of ratepayers for PEF to recover these lower costs pending Commission's review of the new WCTS contracts.

Q: Were any adjustments made to WCTS costs billed PEF?

A: Yes. PFC over-billed PEF $236,111 by inadvertently charging a FOB mine transportation rate for FOB barge coal. PFC issued a refund check to PEF for the total amount of the over-billing in November 2005. This amount was included as a reduction to the ending cost of coal inventory on PEF's November 2005 Schedule A-5.

Q: Have you provided Schedule A12 showing the actual monthly capacity payments by contract consistent with the Staff Workshop on January 12, 2005?

A: Yes. Schedule A12 is included in Exhibit No. __ (JP-3T)).

Q. Does this conclude your direct true-up testimony?

A. Yes

PROGRESS ENERGY FLORIDA

DOCKET NO. 060001-EI

Fuel and Capacity Cost Recovery
Estimated/Actual True-Up Amounts
January through December 2006

DIRECT TESTIMONY OF
JAVIER PORTUONDO

Q. Please state your name and business address.

A. My name is Javier Portuondo. My business address is 410 S. Wilmington Street Raleigh, NC 27601.

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

A. I am employed by Progress Energy Service Company, LLC as Director of Regulatory Planning.

Q. Have your duties and responsibilities remained the same since your testimony was last filed in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval Progress Energy Florida's (PEF or the Company) estimated/actual fuel and capacity cost recovery true-up amounts for the period of January through December 2006.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared an exhibit attached to my prepared testimony consisting of Commission Schedules E1-B through E9 which contain the calculation of the Company's true-up balances and the supporting data and Part A which contains the Company's reprojected capacity cost recovery true-up balance and supporting data.

FUEL COST RECOVERY

Q. How was the estimated true-up over-recovery of $29,814,992 shown on Schedule E1-B, Sheet 1, line 20, developed?

A. The estimated true-up calculation begins with the actual under-recovered balance of $152,254,407, taken from Schedule A2, page 2 of 2, for the month of June 2006. This balance plus the estimated July through December 2006 monthly true-up calculations comprise the estimated $29,814,992 over-recovered balance at year-end. The projected December 2006 true-up balance includes interest estimated at the June ending rate of 0.429% per month. The development of the actual/estimated true-up amount for the period ending December 2006 is shown on Schedule E1-B.

Q. What are the primary reasons for the projected December-ending 2006 over-recovery of $29.8 million?

A. The $29.8 million projected over-recovery is primarily attributable to two factors. First, natural gas prices have been lower than originally projected through June and are projected to be lower from July through December. Second, retail sales have been lower than projected through June due to mild weather, and this trend is also expected to continue through the remainder of the year. While these lower system requirements result in lower fuel revenues, they also result in greater reductions in fuel costs due to lower peaking generation which has a higher than system average fuel cost.

Q. Does Progress Energy Florida expect to exceed the three-year rolling average gain on Other Power Sales?

A. No, Progress Energy Florida estimates the total gain on non-separated sales during 2006 will be $2,527,390, which does not exceed the three-year rolling average for such sales of $5,626,264.

Q. How does the current fuel price forecast for July – December 2006 compare with the same period forecast used in the Company's September 2005 filing?

A. Coal prices remain essentially constant. Natural gas prices decrease an average of $.46/mmbtu or approximately 5.3%. Heavy oil prices increase an average of $.27/mmbtu or 3.6%, while light oil prices increase an average of $2.77/mmbtu or 16.9%.

Q. Were the prices that PEF paid to Progress Fuels Corporation for coal reasonable in amount? If not, what adjustment should be made?

A. Yes, the prices PEF paid to Progress Fuels Corporation for coal were reasonable in amount.

CAPACITY COST RECOVERY

Q. How was the estimated true-up under-recovery of $6,849,038 shown on Part A, Line 47, developed?

A. The estimated true-up calculation begins with the actual under-recovered balance of $20,272,884 for the month of June 2006. This balance plus the estimated July through December 2006 monthly true-up calculations comprise the estimated $6,849,038 under-recovered balance at year-end. The projected December 2006 true-up balance includes interest estimated at the June ending rate of 0.429% per month.

Q. What are the major changes between the original projection for the year 2006 and the actual/estimated reprojection?

A. The $6.8 million under-recovery is primarily attributable to sales being lower than originally projected.

OTHER MATTERS

Q. Does this conclude your estimated/actual true-up testimony?

A. Yes.

PROGRESS ENERGY FLORIDA

DOCKET NO. 060001-EI

Fuel and Capacity Cost Recovery Factors
January through December 2007

DIRECT TESTIMONY OF
JAVIER PORTUONDO

Q. Please state your name and business address.

A. My name is Javier Portuondo. My business address is 410 S. Wilmington Street Raleigh, NC 27601.

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

A. I am employed by Progress Energy Service Company, LLC, in the capacity of Director of Regulatory Planning.

Q. Have your duties and responsibilities remained the same since your testimony was last filed in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the levelized fuel and capacity cost factors of Progress Energy Florida (PEF or the Company) for the period of January through December 2007.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared an exhibit attached to my testimony consisting of Sections A through C. Section A contains our forecast assumptions on fuel price and cyber-security costs. Section B contains fuel cost recovery (FCR) schedules E1 through E10, H1 and the calculation of the inverted fuel rate. Section C contains capacity cost recovery (CCR) schedules.

FUEL COST RECOVERY CLAUSE

Q. Please describe the fuel cost factors calculated by the Company for the projection period.

A. Schedule E1 shows the calculation of the Company's basic levelized fuel cost factor of 5.451 ¢/kWh. This factor consists of a fuel cost for the projection period of 5.52345 ¢/kWh (adjusted for jurisdictional losses), a GPIF penalty of 0.00379 ¢/kWh, and an estimated prior period over recovery true-up of 0.07302 ¢/kWh. Utilizing this basic factor, Schedule E1-D shows the calculation and supporting data for the Company's final levelized fuel cost factors for service taken at secondary, primary, and transmission metering voltage levels. To perform this calculation, effective jurisdictional sales at the secondary level are calculated by applying 1% and 2% metering reduction factors to primary and transmission sales, respectively (forecasted at meter level). This is consistent with the methodology used in the development of the capacity cost recovery factors. The final levelized fuel cost factor for residential service is 5.459 ¢/kWh. Schedule E1-D shows the Company's proposed tiered rates of 5.118 ¢/kWh for the first 1,000 kWh and 6.118 ¢/kWh above 1,000 kWh. These rates are developed in the "Calculation of Inverted Residential Fuel Rate" schedule in Section B.

Schedule E1-E develops the Time of Use (TOU) multipliers of 1.419 On-peak and 0.807 Off-peak. The multipliers are then applied to the levelized fuel cost factors for each metering voltage level which results in the final TOU fuel factors to be applied to customer bills during the projection period.

Q. What is the amount of the 2006 net true-up that PEF has included in the fuel cost recovery factor for 2007?

A. PEF has included a projected over-recovery of $29,814,992. This amount includes a projected actual/estimated over-recovery for 2006 of $30,200,047 less the final true-up under-recovery of $385,055 for 2005 that was filed on March 1, 2006.

Q. What is the change in the levelized residential fuel factor for the projection period from the fuel factor currently in effect?

A. The projected levelized residential fuel factor for 2007 of 5.459 ¢/kWh is an increase of .13 ¢/kWh or 2.4% from the 2006 levelized fuel factor of 5.329 ¢/kWh.

Q. Please explain the reasons for the increase in the levelized fuel factor.

A. The increase in the levelized fuel factor between 2006 and 2007 is mainly driven by escalating fuel costs. Increases in 2007 projected costs per unit compared to 2006 projections are as follows: Coal 5%, heavy oil 36%, light oil 23% and natural gas 12%. The fuel price increases for both oil and natural gas continue to be driven by the worldwide supply and refining capacity limitations coupled with increased global demand and geopolitical uncertainty. As discussed in more detail in the Direct Testimony of Joseph McCallister, the Company has entered into hedging contracts to mitigate the price volatility risk of natural gas and oil.

Q. Why is PEF proposing to continue use of the tiered rate structure approved for use in 2006?

A. In light of continually increasing fuel costs, the Company is proposing to continue use of the inverted rate design for residential fuel factors to encourage energy efficiency and conservation. Specifically, the Company proposes to continue a two-tiered fuel charge whereby the charge for a customer's monthly usage in excess of 1,000 kWh (second tier) is priced one cent per kWh more than the charge for the customer's usage up to 1,000 kWh (first tier). The 1,000 kWh price change breakpoint is reasonable in that approximately 2/3 of all residential energy is consumed in the first tier and 1/3 of all energy is consumed in the second tier. The Company believes the one cent higher per unit price, targeted at 1/3 of the residential class's energy consumption, will promote energy efficiency and conservation. This type of inverted rate design was incorporated in the Company's base rates approved in Order No. 02-0655-AS-EI.

Q. How was the inverted fuel rate calculated?

A. I have included a page in Section B of my exhibit that shows the calculation of the levelized fuel cost factors for the two tiers of residential customers. The two factors are calculated on a revenue neutral basis so that the Company will recover the same fuel costs as it would under the traditional levelized approach. The two-tiered factors are determined by first calculating the amount of revenues that would be generated by the overall levelized residential factor of 5.459¢/kWh shown on Schedule E1-D. The two factors are then calculated by allocating the total revenues to the two tiers for residential customers based on the total annual energy usage for each tier.

Q. What is included in Schedule E1, line 3, "Coal Car Investment"?

A: The $2.8 million on Line 3 represents depreciation expense and return on average investment in rail cars used to transport coal to Crystal River.

Q. What is included in Schedule E1, line 4, "Adjustments to Fuel Cost"?

A. The $39.9 million on Line 4 includes $36.6 million depreciation and return associated with Hines 2 and $3.3 million return on coal inventory in transit. Both of these items were calculated and included in accordance with the Stipulation and Settlement Agreement in Docket 050078-EI.

Q. How do PEF's projected gains on non-separated wholesale energy sales for 2007 compare to the incentive benchmark?

A. The total gain on non-separated sales for 2007 is estimated to be $2,108,443 which is below the benchmark of $3,187,140 by $1,078,697. Therefore, 100% of gains will be distributed to customers based on the sharing mechanism approved by the Commission in Order No. PSC-00-1744-PAA-EI. The benchmark of $3,187,140 was calculated based on the average of actual gains for 2004 and 2005 and estimated gains for 2006 in accordance with Order No. PSC-00-1744-PAA-EI.

Q. Please explain the entry on Schedule E1, line 17, "Fuel Cost of Stratified Sales."

A. PEF has several wholesale contracts with SECI. One contract provides for the sale of supplemental energy to supply the portion of their load in excess of SECI's own resources. The fuel costs charged to SECI for supplemental sales are calculated on a "stratified" basis in a manner which recovers the higher cost of intermediate/peaking generation used to provide the energy. There are other SECI contracts for fixed amounts of base, intermediate and peaking capacity. PEF is crediting average fuel cost of the appropriate strata in accordance with Order No. PSC-97-0262-FOF-EI. The fuel costs of wholesale sales are normally included in the total cost of fuel and net power transactions used to calculate the average system cost per kWh for fuel adjustment purposes. However, since the fuel costs of the stratified sales are not recovered on an average system cost basis, an adjustment has been made to remove these costs and the related kWh sales from the fuel adjustment calculation in the same manner that interchange sales are removed from the calculation. This adjustment is necessary to avoid an over-recovery by the Company which would result from the treatment of these fuel costs on an average system cost basis in this proceeding, while actually recovering the costs from these customers on a higher, stratified cost basis. Line 17 also includes the fuel cost of sales made to the City of Tallahassee in accordance with Order No. PSC-99-1741-PAA-EI, as well as sales to TECO, Reedy Creek and the City of Homestead.

Q. Please give a brief overview of the procedure used in developing the projected fuel cost data from which the Company's basic fuel cost recovery factor was calculated.

A. The process begins with a fuel price forecast and a system sales forecast. These forecasts are input into the Company's production cost simulation model, GenTrader, along with purchased power information, generating unit operating characteristics, maintenance schedules, and other pertinent data. GenTrader then computes system fuel consumption and fuel costs and purchased power. This information is the basis for the calculation of the Company's levelized fuel cost factors and supporting schedules.

Q. What is the source of the system sales forecast?

A. The system sales forecast is made by Corporate Planning using normal weather conditions, population projections from the Bureau of Economic and Business Research at the University of Florida and economic assumptions from Economy.Com.

Q. Is the methodology used to prepare the sales forecast for this projection period the same as previously used by the Company?

A. Yes. The methodology employed to produce the forecast for the projection period is consistent with the Company's most recent filings and was developed with an econometric forecasting model.

Q. What is the source of the Company's fuel price forecast?

A. The fuel price forecasts for natural gas and fuel oil (residual #6 and distillate #2) come from observable market data in the industry and are prepared jointly by the Company's Enterprise Risk Management Department and Regulated Fuels Department. The coal price forecast, calculated by the Regulated Fuels Department, is based on projected deliveries to Crystal River. Market prices and forecast assumptions are provided in Section A of my exhibit.

CAPACITY COST RECOVERY

Q. How was the Capacity Cost Recovery factor developed?

A. The calculation of the capacity cost recovery (CCR) factor is shown in Section C of my exhibit. The factor allocates capacity costs to rate classes in the same manner that they would be allocated if they were recovered in base rates.

Q. Please provide a brief explanation of Section C to your exhibit.

A. <u>Page 1, Projected Capacity Payments,</u> provides system capacity payments to qualifying facilities and other power suppliers. The retail portion of the capacity payments is calculated using separation factors as agreed to in the Stipulation and Settlement Agreement under Docket 050078 as detailed in the Rebuttal Testimony of William C. Slusser Jr.

Page 2, Estimated/Actual True-Up, which was also included in the exhibit to my direct testimony in the 2006 estimated/actual true-up filing, calculates the estimated true-up balance for calendar year 2006 of $6.8 million. This balance is carried forward to Page 1 to be collected during January through December 2007.

Page 3, Capacity Contracts, provides dates and MW associated with the various contracts.

Pages 4 and 5, Calculation of Capacity Clause Recovery Factor, provide the calculation of the capacity cost recovery factor for each rate class based on average 12 CP and annual average demand. The CCR factor for each secondary delivery rate class in cents per kWh is the product of total jurisdictional capacity costs (including revenue taxes) from Page 1, multiplied by the class demand allocation factor, divided by projected effective sales at the secondary level. The CCR factors for primary and transmission rate classes reflect the application of metering reduction factors of 1% and 2% from the secondary CCR factor.

Q. Please explain the increase in the CCR factor for the projection period compared to the CCR factor currently in effect.

A. The projected average retail CCR factor of .959 ¢/kWh is 9% higher than the 2006 factor of 0.879 ¢/kWh. The increase is primarily due to two new firm purchase power contracts. One is with Shady Hills beginning in April of 2007 and ending in 2014. This contract was previously approved in Order No. PSC-04-1276-FOF-EI. The other contract is a purchase from Reliant Energy Florida, LLC, with a term of June 2006 through September 2009. These contracts are listed on page 3 of Section C in my exhibit.

Q. Has PEF included incremental security charges in the 2007 projected capacity amount?

A. Yes. PEF has included $4.6 million of estimated incremental security costs for 2007 in accordance with the Stipulation and Settlement Agreement in Docket 050078-EI. Of this amount, $1.1 million is associated with North American Electric Reliability Council (NERC) Cyber Security Standards CIP-002-1 through CIP-009-1, effective June 1, 2006. The purpose of these standards is to reduce risks to the reliability of bulk electric systems from a compromise of critical cyber assets (computers, software and communication networks) that support those systems. NERC has developed an implementation schedule with a timeframe of 2007 through 2010. These standards can be found at www.nerc.com. In Section A of my exhibit, I have included two pages related to Cyber Security, one is a document that provides a description of each standard and the other is a schedule of costs that PEF projects to expend to comply with these standards. On the second page, only incremental costs will be recovered through the Capacity Clause.

OTHER MATTERS

Q. Has PEF entered into any new contracts since the time of the last fuel filing?

A: Yes, the Company recently entered into a long-term contract with Reliant Energy Florida, LLC, for the purchase of energy and capacity. This contract has a term of June 2006 through February 2009. I am advised that this purchase is needed to maintain a 20% reserve margin for the period in question. PEF has also entered into a contract with Orlando Utilities Commission and is pursuing a contract with The Energy Authority for 2007 winter and summer peaking reserve requirements. The energy associated with these contracts is included on Schedule E7, the capacity is included in Section C, page 1, and the terms of the contract are included in Section C, page 3.

Q. Does this conclude your testimony?

A. Yes.

PROGRESS ENERGY FLORIDA

DOCKET NO. 060001-EI

Fuel and Capacity Cost Recovery
Estimated/Actual True-Up Amounts
January through December 2006
And Projection January through December 2007

SUPPLEMENTAL DIRECT TESTIMONY OF
JAVIER PORTUONDO

Q. Please state your name and business address.

A. My name is Javier Portuondo. My business address is 410 S. Wilmington Street Raleigh, NC 27601.

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

A. I am employed by Progress Energy Service Company, LLC, in the capacity of Director of Regulatory Planning.

Q. Have your duties and responsibilities remained the same since your testimony was last filed in this docket?

A. Yes

Q. What is the purpose of your supplemental direct testimony?

A. The purpose of my supplemental direct testimony is to update the Company's 2006 estimated/actual fuel and capacity calculations presented in my testimony and exhibit no. __(JP-1R) of August 8, 2006, and the Company's 2007 projected fuel and capacity factors presented in my testimony and exhibit no. __(JP-1P) of September 1, 2006. These revisions have been necessitated by significant decreases in fuel commodity prices since my original filings.

Q. Are you sponsoring an exhibit to your supplemental direct testimony?

A. Yes. I am sponsoring Exhibit No. __(JP-1S), which includes three sections. Section A contains revised 2007 fuel projection schedules, including a calculation of variance from my original projection filing, revised projected fuel market prices, Schedules E1 through E10, Schedule H1, and a calculation of the inverted rate. Section B contains revised 2006 estimated/actual schedules, including Schedules E1-B and E2 through E9. Section C contains revised capacity schedules for both 2006 and 2007.

Q. What significant updates have been made to the fuel and capacity cost recovery 2006 estimated/actual and 2007 projection filings since they were originally filed?

A. PEF has updated the commodity prices for all fuel sources used in generation and has re-dispatched the system for the period of October through December 2006 and all of 2007. In addition, PEF has updated its 2006 estimated/actual fuel and capacity schedules with actual data through September 2006. The updated commodity costs are based on forward curves as of October 5, 2006. These costs continue to be fair and reasonable as of the date of this supplemental filing. Given the changes in commodity prices, PEF has also updated its cost of purchased power and revenues from non-separated wholesale sales. The methodology used to dispatch the system in order to forecast generation and purchases is the same as that discussed in my direct testimony filed on September 1, 2006.

FUEL COST RECOVERY CLAUSE

Q. What are the appropriate estimated/actual fuel adjustment true-up amounts for the period January through December 2006?

A. $33,016,382 over-recovery.

Q. What are the appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2007 through December 2007?

A. $32,631,327 over-recovery.

Q. What are the appropriate projected net fuel and purchased power cost recovery amounts to be included in the recovery factor for the period January 2007 through December 2007?

A. $2,109,162,723

Q: What is the appropriate levelized fuel cost recovery factor for the period of January 2007 through December 2007?

A: 5.166 cents per kWh (adjusted for jurisdictional losses).

Q. What are the appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses?

A.

Metering Voltage	First Tier Factor Cents/Kwh	Second Tier Factor Cents/Kwh	Levelized Factors Cents/Kwh	Time of Use: On-Peak Multiplier 1.461	Time of Use: Off-Peak Multiplier 0.788
1. Distribution Secondary	4.832	5.832	5.173	7.558	4.076
2. Distribution Primary	–	–	5.121	7.482	4.035
3. Transmission	–	–	5.070	7.407	3.995
4. Lighting Service	–	–	4.727	–	–

Q. What is the appropriate estimated benchmark level for calendar year 2007 for gains on non-separated wholesale energy sales eligible for a shareholder incentive?

A. $3,005,206

CAPACITY COST RECOVERY CLAUSE

Q. What is the appropriate estimated/actual capacity cost recovery true-up amount for the period of January 2006 through December 2006?

A. $4,799,289 under-recovery

Q. What is the appropriate total capacity cost recovery true-up amount to be collected/refunded during the period January 2007 through December 2007?

A. $5,380,565 under-recovery

Q. What is the appropriate projected net purchased power capacity cost recovery amount to be included in the recovery factor for the period January 2007 through December 2007?

A. $393,207,153

Q. What are the appropriate capacity cost recovery factors for the period January 2007 through December 2007?

A. PEF:

Rate Class	CCR Factor
Residential	1.132 cents/kWh
General Service Non-Demand	0.958 cents/kWh
@ Primary Voltage	0.948 cents/kWh
@ Transmission Voltage	0.939 cents/kWh
General Service 100% Load Factor	0.656 cents/kWh
General Service Demand	0.808 cents/kWh
@ Primary Voltage	0.800 cents/kWh
@ Transmission Voltage	0.792 cents/kWh
Curtailable	0.583 cents/kWh
@ Primary Voltage	0.577 cents/kWh
@ Transmission Voltage	0.571 cents/kWh
Interruptible	0.692 cents/kWh
@ Primary Voltage	0.685 cents/kWh
@ Transmission Voltage	0.678 cents/kWh
Lighting	0.161 cents/kWh

Q. Have you made any changes in your projected capacity contracts for 2006 or 2007?

A. Yes. The 2006 and 2007 capacity schedules have been updated to reflect additional peaking contracts that are necessary to meet winter and summer reserve margin requirements.

Q. Have you made any changes in your incremental security estimates for 2006 or 2007?

A. Yes. We have updated our 2007 projection of incremental security costs. The revised projection is $3.2 million, a decrease of $1.4 million from our original projection of $4.6 million. This decrease is due mainly to more current cost projections as well as the removal of a capital expenditure on a project that is no longer expected to occur.

Q. What are the appropriate credits for transmission allowances for power sales for each investor-owned utility for the years 2005 through 2007?

A. $940,900

Q. Does this conclude your revised supplemental testimony?

A. Yes.

CHAIRMAN EDGAR: Ms. Christensen.

MS. CHRISTENSEN: Thank you.

CROSS EXAMINATION

BY MS. CHRISTENSEN:

Q Good morning, Mr. Portuondo.

A Good morning.

Q I have a few questions about the supplemental direct testimony that you filed on October 25th. Can you please tell us what caused you to file this supplemental testimony and what it contains?

A The -- let me see. Forgive me, but I can't remember the date of the order, but the Commission has a standing policy that the utilities are obligated to continue to monitor the projected costs that they have filed in September of each year. And to the extent that there are material changes that are expected to occur, and they gauge that materialness by using the plus or minus 10 percent, so something that would cause a midcourse correction, there's an obligation on the part of the utility to make the Commission aware of that as late as the day of the hearing so that the appropriate factors can be set going forward.

Having said that, we have a process in place that requires us to continually monitor the forward curves, monitor the market. And when we see that our forward prices are, are indicating that there will be a material change, we automatically set the wheels in motion to update our direct testimony and exhibits for the coming year.

Q Okay. And in this case that's what happened here is you were projecting a downward turn in the cost of fuel?

A That's what resulted with the change in the market.

Q Okay. And looking at Schedule E1, your amended Schedule E1, Line 20, it appears that the total cost for fuel is approximately $2.2 billion; is that correct?

A Yes, it is.

Q Okay. And you're proposing to collect from the retail customers approximately $2.1 billion; correct?

A Again, the numbers that you're looking at had a, a slight modification that took place in our amended -- let's see. Where is it? On October 31st we had a slight amendment to the, to the 25th filing. The total retail fuel costs changed slightly to -- instead of the 2.109 that you see there on the E1 schedule you referred me to.

Q Okay.

A Uh-huh. It changed to 2.095.

Q Okay. And can you explain the difference between the 2.2 billion in the fuel costs and the amended, amended number of 2.095?

A That was a, just a, an over -- an error in one of our spreadsheets. It actually assigned 100 percent of the fuel costs to customers in two months instead of their jurisdictional portion. So it was just an oversight.

Q Now the differential between the 2.2 billion and the 2.095, is that the wholesale revenues?

A It's the wholesale costs associated with fuel.

Q And originally in your testimony you calculated that fuel costs would be 2.3 billion, and that has been reduced to 2.2 billion; is that correct?

A Right. In the September 1st, yes.

Q Correct. Now on Line 4 you originally stated that you needed to recover an additional 2.9 -- or $29.8 million for true-up. Can you explain where that $29.8 million comes from?

A The, it comes from the reprojection of 2006. We, we take the actual experience through, at that point in the September filing it would have been through July, and a reprojection of the remaining months of the year based on the current view of the marketplace, changes in their sales forecast, changes in the purchased power market clearing price. So we incorporate all those changes and compare those changes to the revenue that's going to be collected based on the factor that was set by the Commission in the prior year, and the end result is either an over- or underrecovery that carries into 2007.

Q Okay. And I think we clarified earlier that the reason for the supplemental testimony was due to the reduction in fuel cost projections; is that correct?

A That is correct.

Q And is it my understanding that due to the decrease in the cost of fuel you now expect that the generation fuel expense to go down by approximately 1.9 billion; correct?

A Give or take, that's probably right.

Q Okay. Referring to Line 9 of the schedule, I believe it's Schedule JP-1S. If the purpose -- do you -- are you there?

A Not yet.

Q Okay.

A JP-1S, Line 9. I'm there.

Q Okay. If the purpose of the testimony was related to the reduction in the fuel costs, can you explain why the result in the total cost of the purchased power is going up by approximately 1.9 billion for 2007?

A Sure. The -- you have to understand that part of the process is, is to incorporate the fuel price change into the dispatch model so that the dispatch of the fleet will be different than it was in the original filing. So inherently the original decisions of when we purchased and at what point in time we purchased as compared to running our own plants will change and, as a result of that change, you're going to have a different set of purchase assumptions. And it could have been higher or lower, but it's, it's just going, it's going to free fall based on the dispatch.

Q Let me ask you this. Now on Line 10 you're showing the total cost of power sales dropping from approximately $245 million to approximately $187 million in your supplemental testimony; is that correct?

A Yes.

Q And is that drop because of the fact that you will be paying less for fuel?

A Correct. So, therefore, our sale is going to be at a lower price.

Q Okay. So when you look at JP-1S, it shows that the total cost of fuel has dropped by approximately $117 million in the supplemental testimony as opposed to the original testimony; correct?

A The net 117, yes.

Q And looking back on Line 9 where you say the cost of purchased power will go up in 2007 even though the costs are going down, we'll just make sure that's correct, that's what the testimony is here today, that the purchased power will go up rather than go down.

A That's correct.

Q Now looking at Line 8.

A Yes.

Q Does that show that you plan on spending $261.9 million for purchased power? Or, excuse me, that would be Line 9. Would that be correct?

A Line 9, the refiling says $478 million.

Q I'm looking -- I'm sorry. I have to refer you to a different schedule. It's Schedule E1.

A All right.

Q Line 9 -- or Line 8. I'm sorry. I'm looking --

A E1, which line?

Q I think I'm looking at Line 6. I apologize.

A Okay. Very good.

Q Okay. Does that show $261.9 million for purchased power?

A Yes, it does.

Q Okay. And then you show below that on Line 8, economic purchases; correct?

A That's correct.

Q Can you explain what the economic purchases reflect?

A Well, the economic purchases are those opportunities when the market price is lower than what we can generate that same power for. So it's, it's an opportunity to save the customers by purchasing from someone else rather than operating our own power plant at that time.

Q And on Line 8 you've identified approximately $57 million that you expect to collect for customers for these economic purchases in 2007; is that correct?

A This is -- yeah. The $56 million represents what we will pay for that power.

Q And you show on Line 8 that the cost per kilowatt hour for these economic purchases is almost double the price of the purchased power that you'll be buying for others; is that correct?

A I don't understand the question.

Q If you look at Line 8, the cents per kilowatt hour is 8.6 for the economic purchases.

A Correct. Correct.

Q And on Line 6 the costs or the cents per kilowatt hour for purchased power is 4.38; correct?

A That's correct.

Q And that's approximately double, the economic purchases is approximately double the purchase power; would that be a fair statement?

A That's correct. Yes.

Q Now looking at the fuel cost of the system net generation, that cost of cents per kilowatt hour is 4.9; correct?

A Yes.

Q And so purchased power is approximately a half a cent less than the cost for yourselves to generate the power. Would that be a fair statement?

A Yes. For those megawatts, that's, that's correct.

MS. CHRISTENSEN: Okay. I have no further questions.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Good morning, Mr. Portuondo.

A Good morning.

Q My name is John McWhirter, representing the industrial consumers. And I understand that you can answer questions about almost anything, including the things that Mr. McCallister has testified about. So if I ask you some of those questions, it would obviate the need for calling him as a witness. Is that accurate?

A I will do my best.

Q And so that's wonderful.

I did a slightly different calculation than Ms. Christensen, but as I understood it, on September 1st you anticipated your fuel costs would be 2,255,000,000 some odd dollars.

A $2,225,000,000, is that --

Q Right.

A Yes, sir.

Q And then on October 6th it went down to $2,141,000,000.

A Yes, sir.

Q And then on October 27th it went down to $2,095,000,000.

A That's correct, sir.

Q And my math may be off, but I calculate that to be

$160 million change from what you filed on September 1st to October 27th.

A Let me see. 205 --

Q I didn't have my calculator. I did it on the back of a napkin. So maybe it would help if I used a calculator.

A That's probably pretty close. I need to check. But, yeah, it's a reduction, significant reduction.

Q And presently if your anticipated fuel costs are $2,095,000,000, in order to justify a midcourse correction under the Commission's policies, your fuel costs would have to change $200 million?

A Correct.

Q And presently your fuel is 35 percent natural gas and about 50 percent heavy oil, and the balance is made up of coal, nuclear and light oil?

A Let me see. Yeah. Natural gas is about 26 percent.

Q 26?

A Yes. For 2007 it's about 26 percent.

Q And oil would be what?

A Combined oil is about 15, 16 percent.

Q That would be Schedule E3 that we would look at?

A Yes, sir.

Q So gas is 26 percent and combined oil is 15 percent, you said?

A 15.6, I believe, is what it comes out to. Yes, sir.

It's Page 2 of 2, Schedule E3, Lines 28 through 34.

Q Schedule H1 is a very interesting schedule. Can you refer to that schedule? Your pages aren't consecutively numbered, but it's JP-1 and JP-1S.

A Yes, sir. I'm there.

Q And the last three columns on that schedule show your changes in anticipated costs, and you showed that initially you anticipated that heavy oil would go up 36 percent and gas would go up 28 percent in 2007. And then -- and your supplemental file on October 6th, you anticipate that oil will go up 30 percent in 2007 and gas will go up 29.6 percent, which is you anticipate that gas will go up more than you originally thought it would back in September; is that correct?

A Hold on a second. I'm not -- you're looking at the cost per MMBtu change?

Q I was looking at, yes, the cost per MMBtu. Well, gas -- cost for MCF where you have fuel cost per unit.

A Okay.

Q I would presume that the two would be consistent.

A Uh-huh. That's correct, Mr. McWhirter. The fact is that it's a function of, of how much of a change occurred in reestimating 2006.

Q Uh-huh.

A As compared to how much of a change occurred in the reprojection of 2007. So we were projecting in the original filing that gas -- the change in gas year over year was about 28.7 percent. I believe that's the number you quoted, the original.

Q Right.

A And then in the revised the change year over year was 29.6 percent. But both the, both years changed because of the refiling, and they both changed -- the costs in both years went down.

Q The costs went down but the cost per unit went up.

A No, sir. The cost per unit in 2006 in the original filing was 8.13.

Q Uh-huh.

A And in the revised filing it's 7.56. So the cost per MCF went down.

Q Well, I won't delay it any further because I know we've got a lot to cover today.

If you go to Schedule E1, JP-1S, the projected market price for fuel type, in January of 2007 originally you projected that gas would be $11.94 per MMBtu and in JPS -- JP-1S you have dropped that clear down to $10.04. And it would appear that the reduction in gas price is fairly consistent throughout the remainder of the year; is that correct?

A That is correct.

Q And you haven't done an updated JP-1S that you filed with the Commission in connection with the filing you made last week, did you? Have you?

A These, these prices did not change as a result of that amendment to our supplemental testimony.

Q How do these prices compare to the NYMEX prices?

A These prices are higher.

Q Yes.

A Because these represent the spot price. And NYMEX does not represent the spot price; it's the financial contract. So you have to convert NYMEX to a spot price and then they're more comparable, or comparable.

Q What do you do -- what items of cost do you add to bring it to spot price?

A From what I understand, there's an EPRI formula that's applied to the NYMEX price in order to convert it from the financial contract, because that's what NYMEX represents, to a spot price, which would be the price that someone could actually physically buy it for in the prompt month.

Q Is this what you buy it for at Burner Tip or is this what you buy it for at Henry Hub or at the City Gate?

A I believe this would be Henry Hub.

Q So that price would be marked up by your transportation costs?

A Correct. A basis differential.

Q For -- I was perplexed by this. I thought the interstate pipelines were regulated. Is that not accurate?

A I haven't studied interstate pipeline regulations.

Q Well, your testimony says that interruptible transportation rates and availability are based on expected tariff rates and market conditions.

A Oh, yes.

Q I understand tariff rates, but I don't understand market conditions. What does that mean?

A Well, you could have force majeures, you could have -- since this is interruptible capacity, they could interrupt the transportation path for God knows what reasons under their tariff, and that could cause you not to be able to receive the gas.

I'm not an expert in the tariff itself and all the underlying optionality it may have.

Q But it's not a fixed price based on a tariff. If you're interrupted, that doesn't affect your price. It affects your ability to get the gas, doesn't it?

A That's true. The way I understand the -- you have a -- you can, you can either take the gas firm or you can take it nonfirm.

Q Uh-huh.

A So there's going to be a tariff price for each one. The nonfirm is subject to interruption.

Q Are the prices charged by Gulfstream different than the prices charged by FGT?

A I could not speak to that. I'm not sure.

Q You don't take gas from Gulfstream as well as FGT?

A I do, but I just don't know the, the rates between the two.

Q It's hard for the layman to visualize you going out the day before you need gas and buying it in the spot market. As I understand what happens is you enter into a long-term contract with a supplier that has a price that's based upon the spot market. So you have a secure supply of gas, it's just that the price for that gas is flexible. Is that what happens in the real world?

A It's an index-based contract, so it will track whatever the market, whatever the spot price is at the time that you're taking delivery of the gas.

Q But there's -- barring a force majeure, it's unlikely that your gas supply will, or the reliability of your gas supply will be interrupted. It's just a matter of what you pay for it. Is that the deal?

A Yeah. That's just the, the pricing terms --

Q Uh-huh.

A -- are variable rather than fixed.

Q So what happens with hedging is that you try to eliminate the volatility in that price by paying money in advance to get a fixed price for your fuel.

A You, I mean, you could do it in many ways. One way would be to enter into a fixed price contract with the provider of that commodity so, therefore, you're not subject to the volatility of the market. Of course, the counterparty that you're buying from is going to put in some sort of a little kicker into that fixed price in order to cover his risk. But it provides certainty and eliminates the volatility.

You can enter into other financial type contracts that previous witnesses have articulated such as swaps that are financial instruments to try and minimize that volatility. But, yes.

Q Okay. Well, if you entered into a fixed, a supply contract with a fixed price, would you classify that as a physical hedge as opposed to a financial hedge?

A Yes.

Q I see. And your testimony -- Mr. McCallister's testimony said you were, I believe, 67 percent hedged in 2006. It's kind of interesting to me, in his testimony he gave the hedging percentages, but in the risk management plan attached to it those were blanked out. And can you tell me why you put it in at one place and blank it out at another?

A The risk management report is forward looking, where his quote, other percentages were related to 2006 and they've already been executed.

Q I see. And so there's no trade secret in connection with telling what, what your hedge position was historically, but it is a trade secret to tell what your plan is for the future with respect to the percentage of the commodity that you're going to hedge?

A Yes.

MR. BURNETT: Commissioner, I'm sorry. If I could object to the extent he's using the term "trade secret." That has a legal, independent legal meaning. And I would ask to the extent he's asking this witness to give effect to that legal term -- I would object for cause as a, for a legal opinion.

CHAIRMAN EDGAR: Mr. McWhirter, can you restate?

MR. McWHIRTER: How about business secret? That isn't a --

MR. BURNETT: Confidential might work.

MR. McWHIRTER: Confidential. All right.

BY MR. McWHIRTER:

Q You keep that confidential. And why do you need to keep it confidential, Mr. Portuondo?

A We need to keep it confidential in order not to adversely influence the marketplace. We, we don't want our counterparties knowing how much we're going to be looking to, to hedge and, therefore, influence the price at which they will charge us for those hedges.

Q I would think that liquidity would be an important factor when you're hedging. If you have an open market where there are a lot of traders, there's greater liquidity. Would that be a fair statement?

A If you're in a market with more traders, there's more liquidity, yes.

Q And from the testimony that we've heard so far from Mr. Yupp and Mr. Ball, they indicate that most of their transactions are over the counter as opposed to going to the NYMEX exchange. What is your company's policy? Do you trade on the NYMEX or do you go to over-the-counter transactions?

A We do not trade on the NYMEX. We enter into a contract with specific counterparties that meet our credit quality standards.

Q Can you tell me the reason that you don't go to the public exchange, the commodity exchange as opposed to one-on-one dealings?

A I personally can't. I need to defer that to Mr. McCallister. I believe there's a cost associated with the NYMEX, and there's probably other factors associated with that. But I'll have to defer that.

Q But wouldn't it enhance -- I would imagine now that electric companies are big in gas and all the recent power plants have been gas plants, that it would really enhance things if people would operate on exchange as opposed to one-on-one phone calls with bankers. Why is that philosophy incorrect?

A I could not tell you, sir.

Q I was perplexed by one other thing that I heard yesterday. And I'm handicapped in hearing, so I may have heard it wrong. But Mr. Yupp said that his company might pay as much as $100 million or lose as much as $100 million in risk premiums, and Mr. Ball said that his company didn't pay any risk premiums. And can you explain how it is with your company? Do you pay risk premiums?

MR. BUTLER: I'm going to object to the characterization of Mr. Yupp's testimony. It's referring to a loss concerning the risk premiums. I think the discussion was of simply paying those amounts.

MR. McWHIRTER: I would accept that correction and eliminate loss but just put premium.

BY MR. McWHIRTER:

Q What does your company do? Do you pay commissions and brokerage fees, transaction costs and risk premiums to your counterparties?

A We've been fortunate enough -- since we do bilateral contracts we haven't had transaction fees. But we have purchased some instruments that require a premium, and to date -- or the balance to date is only about, it's about $2.7 million.

Q $2.7 million is all you've paid in risk premiums for your transactions in 2006?

A Actually it's not for transactions in 2006. These transactions won't settle until 2009. But we've already paid them today in order to enter into that hedge.

Q As an accountant, what year do you book that?

A I actually don't book it until 2009 when the transaction settles.

Q And you're booking things now that occurred in 2003?

A No. It'll all depend on the period for which the hedge was put on. So I actually don't have any premiums that are clearing. This is the only one that we've had to pay a premium for thus far.

Q Under your risk management program how far out can you go with your hedges currently?

A Right now we are through 2010. So that's four years.

Q Why did you elect to go for four years as opposed to one year?

A Well, our guiding principle is to reduce price volatility. And I believe the review by the folks that are more knowledgeable in hedging felt that that was a fair and reasonable approach to systematically buy over that period, it could have been something more or less, but we just chose that period, and try to average the cost associated with those hedges. So it's dollar averaging.

Q Mr. McCallister indicated that through July your mark to market gains were, I think he said, something like $26 million ahead of the spot market cost. Is that -- it's on

Page 4 of his testimony. Well, it must not be.

He said, "The company's hedging activities" -- this is Page 4, unnumbered line. "The customers' savings produced of $87.7 million for the seven-month period ending July 2006." Can you tell me what it is through your most recently calculated period? Is that September or October?

A Through September we're now up to $123 million in savings.

Q How do you calculate those savings, Mr. Portuondo?

A It's the differential between the spot price and the hedged price.

Q And is that on transactions that are currently taking place, or you're booking transactions that may not close until 2010?

A No. These are, these are for the -- gosh, I can't remember.

I think this is, this -- what you're seeing here, the 123 represents what has actually settled. So it's those hedges that have expired, and that's the benefit customers have received based on that calculation of what the hedge price was that customers were charged versus what the spot price was at that same point in time that they would have paid in the absence of the hedge.

Q FASB 133, is that how you account for derivatives?

A Yes. But that's a bit different. I think that's what your original question was going towards is the mark to market. And that does -- when you do a mark to market, that does take into consideration those positions that have not yet settled. So like I mentioned that 2009 hedge. So it would take into consideration what was your hedge price and what does the market say 2009 will be? And then you do your mark to market and that will tell you where your gain or loss is at any point in time.

Q So for your company's hedging purposes, you don't follow that accounting standard. You follow some other standard?

A No. No. We follow that standard for accounting purposes. But I think your question and the genesis of our testimony is how much has been realized by customers.

Q Okay. Give me just -- I hate to take so much time on this, but it's fascinating.

A No. It's all right.

Q Give me just a quick capsule understanding of how you calculate that $123 million in savings.

A Okay. Let's say in July I had a hedge for five, for $5 for 10 MCFs and the price was $8 on the spot price, on the spot market. So I have a $3 difference; right?

Q Right.

A Times the number of MCFs. So that would be $30 in savings that the customer has realized because the company entered into that hedge for $5 and had the ability to not have to be subject to the volatility of the market.

Q Are most of your hedges on long-term contracts as opposed to short-term transactions?

A I'm not sure I understand that.

Q Well, common knowledge is that in a, in a time of falling prices if you've hedged at a higher price, you're going to lose money. And what we've seen in the last few months is falling prices. But it looks like your hedges, you're making money in a time of falling prices, which is, goes against what I would see as common understanding. And how does that come about?

MR. BURNETT: Object to that -- pardon me. I'll object to that question, given the fact that Mr. McWhirter's question assumes facts not in evidence.

BY MR. McWHIRTER:

Q Well, let me -- what is the common understanding as to what happens to hedging when prices fall as opposed to prices rising?

A I think that's a better question suited for Mr. McCallister.

Q Okay.

A But I can generally say -- and to the point I think you were going at, with our financial hedging, I mean, we're hedging particular months in the future, not, you know, we're not entering into an entire year at one time at one hedged price. So we're buying through the curve and we're trying to take advantage of those changes in projections in order to levelize over time the impact to customers. And that's just the strategy we elected to pursue, which is an averaging over time.

Q I understand that part. My question was when prices are falling and you've hedged based upon forecasts for prices that were higher than the current spot price, intuitively I would think that that would result in a loss. But it hasn't occurred in your situation.

A No. No. Because, because we're not putting all our eggs in one basket on that one hedge. We're buying increments through the curve.

Q Okay.

A So on an average we're what happens to be favorable on the average.

Q Does your current fuel expense include any cost for operating and maintenance of your hedging program?

A No, it does not.

Q Beg your pardon?

A No, it does not.

Q It does not.

And one mechanism for hedging is to diversify your generation. And you have good diversity: You have nuclear, you have oil, you have gas, and you have the opportunity to buy from other people. And Ms. Christensen pointed out that she thought it was kind of peculiar you were paying $96 for economy purchases and only $36 when you buy from qualifying facilities.

How come economy purchases were so much more expensive? Let's look at E1.

A One reason, Mr. McWhirter, is the majority, if not all, of the economy purchases are trying to offset peaking and your QF contracts are dispatched as baseload products. So you need to keep that into consideration is what type of generation are you trying to displace?

Q You have a good number of industrial consumers in your service area, as I understand it; is that correct?

A That is correct.

Q And industrial people can make electricity using waste heat; is that correct?

A I have no idea. I'm not in that area.

Q Okay. I won't pursue that further.

Well, I will. Do you know as a conservation measure whether your company attempts to encourage industrial people with waste heat to make electricity?

A I know that we have looked at purchasing, you know, renewable generation, but that's the extent of my expertise in that area.

Q If you were a regulator, Mr. Portuondo, and you were trying to evaluate whether a hedging program was reasonable or whether it was unreasonable, what standard would you -- how would you measure it to determine whether it had achieved the purposes that it should be designed to achieve?

MR. BURNETT: I would object to that question as to relevance. Unless Mr. Portuondo has a new job I don't know about, I'm not sure that's particularly relevant.

(Laughter.)

MR. McWHIRTER: Well, Mr. Portuondo moves around, as we've seen.

CHAIRMAN EDGAR: I don't see any empty seats.

MR. McWHIRTER: I can rephrase the question, Madam Chairman.

THE WITNESS: Can I be the sixth Commissioner?

MR. McWHIRTER: Election day is here today.

(Laughter.)

BY MR. McWHIRTER:

Q In any event, what -- how do you measure the success of a hedging program?

A Mr. McWhirter, our, our objective is to minimize price volatility. So I think as long as we are entering into prudent transaction and not speculative transaction, I think it's always successful because you're going out there trying to create some stability for the customers year over year.

And I think it, you know, I think it's inherently effective and successful just by virtue of, of pursuing a hedging program.

Q So you can't give us a quantitative measure of the program.

A I cannot.

Q If your company has experienced a significant increase in prices, how late in the year as a practical matter can you wait to ask for a midcourse correction? I don't think you'd ask for a midcourse correction from September on because it's so close to the end of the year, would you?

A That could occur. I mean, that could occur. You could elect to request a midcourse beginning in September, but choose to spread that impact over the remainder of that year plus the coming year just in order to, you know, minimize the rate shock to customers.

And actually I think that has occurred historically. There has been, I think, one instance where that has occurred.

Q My observation has been that they normally happen in the spring, and after July people don't do it much anymore. But is that inaccurate?

A No. No. No. I think that is predominantly how it has occurred is that we, if we do experience something late in the year that causes the 10 percent threshold to be reached, there is a tendency on the part of Progress to notify the Commission and indicate to them how much of an impact it would be if you attempted to recover that 10 percent over just that short period of time remaining in the year.

And in our, some of our filings we indicated to the Commission that we were willing to wait and just roll that into the one-one change in rates.

Q When you do a midcourse correction, are you necessarily locked in to the last five months if it goes in in July or the last three months if it goes in in September?

A Typically, I mean, that is the recovery that's contemplated. You're, again, trying to make sure that the cash flow is continuing to the company; you're trying to reduce the interest impact to customers on the underrecovery. So you're weighing all those factors in determining the period of time over which costs should be recovered.

You're also, you know, weighing the fact that, you know, intergenerational inequities, it's minor, but that would be something that you would just check off the list and support.

MR. McWHIRTER: Thank you very much, Mr. Portuondo.

I tender the witness, Madam Chairman.

CHAIRMAN EDGAR: Thank you, Mr. McWhirter.

No questions?

CAPTAIN WILLIAMS: No questions.

CHAIRMAN EDGAR: Questions for this witness on cross by any other party.

MR. STONE: If I may, Madam Chairman.

CHAIRMAN EDGAR: You may.

CROSS EXAMINATION

BY MR. STONE:

Q Mr. Portuondo, Mr. McWhirter asked you a question about your incremental O&M related to hedging costs. Do you recall that question?

A Yes, I do.

Q You indicated that this fuel cost projection does not include those incremental O&M costs for the hedging activities; is that correct?

A That is correct.

Q Is that because Florida Progress has rolled those incremental costs into its base rates as a result of the last rate case settlement?

A Yes, it is.

Q Were you an active participant on behalf of Florida Power Corp, now Progress Energy, in the review of electric utilities' risk management policies and procedures that was conducted by this Commission in Docket Number 011605-EI?

A Yes, I was.

Q Did you participate in Florida Power Corp's negotiation or consideration of the proposed resolution of issues that was approved by the Commission and attached to Order Number PSC-021484-FOF-EI as issued on October 30th, 1980 -- I'm sorry -- 2002?

A Yes, I was.

Q Were you here yesterday when Mr. McWhirter asked questions based on Paragraph 4 of Attachment A to that order?

A Yes, I was.

MR. STONE: Okay. With the Chair's permission, I'd like to give a copy of the order to Mr. Portuondo.

BY MR. STONE:

Q Turning to Page 6 of the order, which takes you and has Paragraph 4 of Attachment A, the language that was read yesterday, is it your opinion as a participant in the negotiation or consideration of this proposed resolution that that precludes fuel cost recovery of incremental O&M costs for hedging activities after 12/31/2006?

A No, it doesn't.

Q Okay. Noting about just beyond the halfway point of Paragraph Number 4 there is a sentence that starts out, "In September." Do you see that?

A Yes.

Q Would you mind reading that sentence in its entirety to the Commission?

A Certainly. "In September of each year from 2002 through 2006 as part of the projected fuel filing, each utility shall provide an itemization of the projected operating and maintenance expenses for the projected period by functional category for each fuel cost recovery, fuel cost recovery as requested, the incremental expense."

Q Based on that sentence then is it appropriate if a utility has not had the opportunity to roll the incremental costs into its base rates, is it appropriate for a utility to continue to request fuel cost recovery for those incremental O&M expenses related to hedging activities if it so desires?

A Yes.

MR. STONE: Thank you. I have no further questions.

CHAIRMAN EDGAR: Thank you, Mr. Stone. Any other parties with questions on cross for this witness? No.

Questions from staff.

MS. BENNETT: No questions right now. Thank you.

CHAIRMAN EDGAR: Thank you.

Commissioners, any questions for Mr. Portuondo? No.

Mr. Burnett.

MR. BURNETT: No redirect, Madam Chairman. And, if appropriate, I would move Mr. Portuondo's testimony and exhibits into the record, if they were not being done so in the comprehensive exhibit.

Madam Chairman, if I may also, this may be a ripe time to revisit the potential stipulated issues. I believe Ms. Bennett suggested a procedure by which after Mr. Portuondo testified and was cross-examined we could revisit Issues 2, 3, 6, 30, 31, 32 and 8. I believe Ms. Christensen was going to decide if she still had remaining problems or could stipulate.

MS. CHRISTENSEN: I think at this time we can remain with no position on those issues.

CHAIRMAN EDGAR: Okay. The position of no position is noted. And, Mr. Burnett, the exhibits will be entered into the record.

MR. BURNETT: Thank you.

(Exhibits 30 through 34 admitted into the record.)

CHAIRMAN EDGAR: Ms. Bennett, any other matters as regarding this witness?

MS. BENNETT: I have no other matters regarding this witness, and we can move those in as stipulated items for the vote.

CHAIRMAN EDGAR: Okay. Those issues will be moved as stipulated.

MR. BURNETT: Thank you.

CHAIRMAN EDGAR: Mr. Portuondo, you are excused. Thank you very much.

Mr. Burnett, your witness.

MR. BURNETT: Thank you. We would call Joseph McCallister.

MR. McWHIRTER: Madam Chairman, Mr. Portuondo answered everything I wanted to ask. Unless you have other things for McCallister or somebody else does, I don't need to hear him.

MR. BURNETT: Madam Chairman, we were simply calling him for any remaining questions on 15A. If no one else has questions, we can, we can have him step down. It's your pleasure.

CHAIRMAN EDGAR: Are there any parties that will have questions for Mr. McCallister on Issue 15A? And, Mr. McWhirter, you said no questions.

MR. McWHIRTER: No, ma'am.

CHAIRMAN EDGAR: Commissioners, any questions for Mr. McCallister?

I note here on the prehearing order that Witness McCallister was to adopt the prefiled testimony and exhibits of Witness Murphy. Ms. Bennett, what do we need to do on that point?

MS. BENNETT: Note for the record that -- if you will just note it for the record that Mr. McCallister has adopted the testimony of Pamela Murphy, that should be sufficient.

CHAIRMAN EDGAR: Okay. So noted for the record.

MR. BURNETT: Thank you.

CHAIRMAN EDGAR: Thank you.

Mr. McCallister, thank you very much. You are excused.

Okay. And on that efficient note, let's go ahead and take a ten-minute break, and then, Mr. Burnett, we will start back with you.

MR. BURNETT: Thank you.

(Recess taken.)

CHAIRMAN EDGAR: We will go back on the record. And Mr. Burnett.

MR. BURNETT: Thank you, Madam Chairman.

Before we took the break, I don't think that I formally moved in Mr. McCallister's testimony and his adopted testimony of Ms. Murphy, and Exhibits 35 through 39. So I would move those at this time.

CHAIRMAN EDGAR: The prefiled testimony as described and the exhibits will be moved into the record.

(Exhibits 35 through 39 marked for identification and admitted into the record.)

PROGRESS ENERGY FLORIDA

DOCKET NO. 060001-EI

Fuel and Capacity Cost Recovery
January through December 2007

DIRECT TESTIMONY OF JOSEPH MCCALLISTER

Q. Please state your name and business address.

A. My name is Joseph McCallister. My business address is 410 South Wilmington Street, Raleigh, North Carolina 27601.

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

A. I am employed by Progress Energy Carolinas in the capacity of Director, Gas & Oil Trading.

Q. Have you previously filed testimony before this Commission in this ongoing docket?

A. No, I have not. I was recently appointed the responsibilities for the procurement and trading of natural gas and oil on behalf of Progress Energy Florida (Progress Energy or the Company).

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

A. I obtained a Bachelor of Science in Business Administration majoring in Accounting from Ohio State University in 1987. I was recently appointed the Director, Gas and Oil Trading for Progress Energy Carolina's. I joined Progress Energy Service Company LLC in November 2003. Prior to my current position, I served as Director of Portfolio and Market Risk Assessment in the Enterprise Risk Management Group. Subsequent to my tenure with Progress Energy, I spent approximately 10 years in various positions at energy trading and asset generation based companies. Previous management experiences include gas and power scheduling, real time operations, gas storage asset management, integration and commercial optimization of generation, fuel and load portfolios, contract management, and corporate planning.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and address PEF's Risk Management Plan for fuel procurement in 2007. In addition, I will address the Company's actions to mitigate price volatility through its hedging strategies.

Q. Has PEF developed its Risk Management Plan for fuel procurement in 2007 in accordance with the Resolution of Issues proposed by Staff and approved by the Commission in Order No. PSC-02-1484-FOF-EI, Docket No. 011605-EI?

A. Yes. PEF's Risk Management Plan was prepared in accordance with the Resolution of Issues approved by the Commission and is attached to my prepared testimony as Exhibit No. ___ (JM-1P). Certain confidential information in the exhibit has been redacted, consistent with the Company's request for confidential classification of this information.

Q. What are the objectives of PEF's hedging plans for 2007?

A. The objectives of PEF's natural gas, heavy (No. 6 or residual) fuel oil, and light (No. 2 or distillate) fuel oil hedging plans are as follows:

1) Mitigate price risk and volatility, 2) provide price certainty to smooth out prices over time, 3) maintain a diverse portfolio of volumes and prices over time, and 4) where the potential exists and is consistent with our first three objectives, to provide ratepayer savings through lower natural gas and oil costs.

Q. Please describe the hedging activities Progress Energy plans for 2007 for its natural gas requirements.

A. PEF executes physical and financial natural gas hedging in accordance with the Company's approved natural gas hedging strategy. PEF has and will continue to utilize physical fixed price agreements and financial products, including fixed price swaps and options to hedge natural gas prices. As of July 31, 2006, the Company has hedged approximately 41% of its 2007 projected natural gas usage. The weighted average fixed priced paid for physical purchases and fixed priced financial swaps executed for 2007 is approximately $6.47/MMBtu.

Q. Please describe the hedging activities PEF plans for oil in 2007?

A. The Company has been and continues to use financial products including fixed price swaps and options to hedge its projected heavy oil requirements. As of July 31, 2006, the Company has hedged approximately 36.2% of its 2007 projected heavy oil usage at an equivalent fixed price of $7.56/MMBtu.

Q. What is PEF's time frame for hedging forward prices of natural gas and oil?

A. The Company's current hedging strategy now extends for a current plus 4 year period.

Q. What were the results of PEF's hedging activities during the January through July 2006 period?

A. The Company's hedging activities produced customer savings of approximately $87.7 million for natural gas and heavy oil. For the seven-month period from January through July 2006, PEF hedged approximately 69.4% of its natural gas consumption and approximately 68.5% of its heavy oil consumption.

Q. Does this conclude your testimony?

A. Yes, it does.

PROGRESS ENERGY FLORIDA

DOCKET NO. 060001-EI

Fuel and Capacity Cost Recovery
Final True-Up for the Period
January through December, 2005

DIRECT TESTIMONY OF
PAMELA R. MURPHY

March 1, 2006

Q. Please state your name and business address.

A. My name is Pamela R. Murphy. My business address is P. O. Box 1551, Raleigh, North Carolina 27602.

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

A. I am employed by Progress Energy Carolinas, Inc., as Director, Gas & Oil Trading.

Q: Have your duties and responsibilities remained the same since you last testified in this proceeding?

A: Yes

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the additional costs that Progress Energy Florida (PEF or Company) incurred for natural gas and No. 6 fuel oil due to storm events during the 2005 hurricane season. I will also describe the Company's efforts to mitigate the effect of natural gas and oil supply interruptions caused by those storms.

Q. Please summarize your testimony.

A. PEF's natural gas and fuel oil supplies were affected to different extents by the storm events of the 2005 hurricane season. Tropical Storm Cindy, Hurricane Dennis, Hurricane Katrina and Hurricane Rita interrupted natural gas production in the Gulf of Mexico causing PEF's contract ("term") suppliers to invoke *force majeure* provisions in their contracts. PEF used various means to mitigate the resulting impact on its natural gas supplies including replacement gas purchases on the spot market. Because the spot purchase prices were higher than term contract prices, PEF experienced higher total natural gas costs. This differential in prices caused PEF to incur $45,528,816 of incremental natural gas costs. The Company also incurred No. 6 oil barge transportation charges of $1,572,748 to provide supplemental supplies during the second half of October through the end of 2005. Thus, in total, PEF incurred $47,101,564 of incremental natural gas and No. 6 fuel oil costs as a result of the storm events of the 2005 hurricane season.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. I am sponsoring Exhibit No. ___ (PRM-1), a table showing the calculation of total incremental natural gas costs attributable to 2005 storm events and Exhibit No. __ (PRM-2), a report of the Mineral Management Service entitled the "Hurricane Katrina/Hurricane Rita Evacuation and Production Shut-in Statistics"

Q. Which storm events during the 2005 hurricane season affected PEF's term natural gas supplies?

A. During the 2005 hurricane season, four major storms affected term gas supplies for PEF: Tropical Storm Cindy affected term gas supplies from July 5th to the 7th; Hurricane Dennis affected term gas supplies from July 8th to the 13th; Hurricane Katrina affected term gas supplies from August 26th to September 19th; and Hurricane Katrina/Hurricane Rita affected term gas supplies from September 20th through October 17th. Hurricane Ophelia, Tropical Storm Tammy, and Hurricane Wilma affected the Florida area but PEF did not experience any gas supply interruptions during these storms.

Q. How did Tropical Storm Cindy, Hurricane Dennis, Hurricane Katrina and Hurricane Rita affect natural gas production in the Gulf of Mexico?

A. To different degrees, these storms caused natural gas production in the Gulf of Mexico to be "Shut-in." (Shut-in occurs when natural gas is no longer flowing from the production platforms; in this case because the platforms were evacuated and production was turned off at the well-head.) According to the "Hurricane Katrina/Hurricane Rita Evacuation and

Production Shut-in Statistics" provided by the Mineral Management Service, a bureau of the U.S. Department of Interior, the total cumulative Shut-in gas production through January 9, 2006 because of Hurricane Katrina and Hurricane Rita was 581.7 Bcf. This equates to approximately 15.9% of the yearly production of gas in the Gulf of Mexico. A copy of the Mineral Management Service's Report is provided as Exhibit No. __ (PRM-2).

Q. What effect did Tropical Storm Cindy, Hurricane Dennis, Hurricane Katrina and Hurricane Rita have on PEF's term gas supplies?

A. Due to the Shut-ins caused by the storms, PEF's term gas suppliers invoked *force majeure* clauses in their contracts. Under *force majeure*, these suppliers were not obligated to perform, and PEF was not obligated to pay under the contracts. Total term gas supply interruptions attributable to *force majeure* events caused by Tropical Storm Cindy were 30,160 decatherms (Dths) and 1.1 million Dths for Hurricane Dennis. For Hurricanes Katrina and Rita, total term gas supply interruptions caused by *force majeure* events were 6.5 million Dths. Exhibit No. __ (PRM-1) shows the daily volumes of term natural gas supplies that were not delivered due to the *force majeure* events associated with Tropical Storm Cindy, Hurricane Dennis, Hurricane Katrina and Hurricane Rita.

Q. Are PEF's term gas suppliers obligated to make up the deliveries by providing additional natural gas in the future?

A. No. Under the *force majeure* clauses in our supply contracts, suppliers are relieved of any obligation to perform for the period of the *force majeure* event and are not obligated to provide additional gas in the future.

Q. How did PEF mitigate term gas supply interruptions caused by Tropical Storm Cindy, Hurricane Dennis, Hurricane Katrina and Hurricane Rita?

A. During each storm and its aftermath, PEF mitigated gas supply interruptions by: (1) purchasing replacement gas supplies from the spot market; (2) purchasing gas supplies from third party storage accounts; (3) utilizing three different 10-day storage daily call options for July through October; (4) utilizing fuel oil to the extent necessary for reliability purposes; and (5) working with Gulfstream Natural Gas System and Florida Gas Transmission to use existing gas in the pipelines to the extent operationally feasible to meet load (Operational Balancing Account).

Q. How does PEF's Operational Balancing Account on Gulfstream Natural Gas System help mitigate gas supply interruptions?

A. PEF's Operational Balancing Account on Gulfstream Natural Gas System provides for a daily balancing mechanism to account for the difference in actual burns versus actual gas deliveries. When PEF has a positive imbalance in this account, we work with Gulfstream Natural Gas System to use this excess gas to supplement gas burns to the extent operationally feasible on Gulfstream Natural Gas System's pipeline. PEF utilized this account to help mitigate the natural gas interruptions caused by Tropical Storm Cindy, Hurricane Dennis, Hurricane Katrina and Hurricane Rita.

Q. How did the storms of the 2005 hurricane season affect PEF's fuel oil supplies and how did the Company respond?

A. During the 2005 hurricane season, the following storms affected fuel oil supplies for PEF: Tropical Storm Cindy affected fuel oil supplies from July 5th to the 7th; Hurricane Dennis affected fuel oil supplies from 8th to the 10th; Hurricane Katrina affected fuel oil supplies from August 25th to the 29th; Hurricane Rita affected fuel oil supplies from September 20th to the 24th; and Hurricane Wilma affected fuel oil supplies from October 20th to the 24th. Each of these storms caused interruptions of fuel oil deliveries to most of PEF's oil-fired plants and deliveries of petroleum products to Florida as a whole.

Hurricanes Katrina and Rita caused delays to barge deliveries of No. 6 fuel oil that resulted in PEF inventories to decline after these storms. Thus, PEF procured additional barge transportation to supplement its normal contract barge supplies. From October 14th through November 9th, six supplemental barges were received by PEF at an extra cost of $1,206,348. On November 10th, one of the barges that regularly delivers No. 6 fuel oil to PEF struck a submerged platform that was sunk by Hurricane Rita. This barge is no longer available for charter service. As a result, PEF spent $366,400 on supplemental barges from November 29th through year end 2005. A total of $1,572,748 of incremental No. 6 fuel oil transportation costs were incurred by PEF to supplement barge delivery capacity that was delayed or damaged as a result of the storms in 2005.

Q. How did you determine the incremental natural gas costs attributable to the 2005 storms?

A. Additional natural gas costs attributable to the 2005 storms consist of incremental costs of spot gas purchases made to replace cuts in term supplies resulting from *force majeure* events. As shown on Exhibit No. __ (PRM-1), incremental natural gas costs were derived by multiplying the daily gas cost difference by the daily spot volume purchased to replace cuts in term supplies. The daily gas cost difference was calculated by subtracting the average spot natural gas cost from the average term gas cost for each day affected by the storms. The sum of the daily incremental gas costs reflects the total incremental gas cost of $45,528,816 shown on Exhibit No. __ (PRM-1).

Q. Does this conclude your testimony?

A. Yes

PROGRESS ENERGY FLORIDA

DOCKET NO. 060001-EI

Fuel and Capacity Cost Recovery
Final True-Up for the Period
January through December, 2005

DIRECT TESTIMONY OF PAMELA R. MURPHY

April 1, 2006

Q. Please state your name and business address.

A. My name is Pamela R. Murphy. My business address is P. O. Box 1551, Raleigh, North Carolina 27602.

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

A. I am employed by Progress Energy Carolinas, Inc., as Director, Gas & Oil Trading.

Q. Have your duties and responsibilities remained the same since you last testified in this proceeding?

A. Yes, my responsibilities for the procurement and trading of natural gas and oil on behalf of Progress Energy Florida (PEF or the Company) have remained the same.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize the results of PEF's Risk Management Plan for 2005, and to provide the information required by Order No. PSC-02-1484-FOF-EI, which approved the resolution of the hedging-related issues pending before the Commission in Docket No. 011605-EI.

Q. Have you prepared exhibits to your testimony?

A. Yes, I have prepared Exhibit No. ___ (PRM-1T), a three-page summary of the results of the Company's Risk Management Plan for the true-up period, and Exhibit No. ___ (PRM-2T), a one-page listing of the hedging information required by the Commission-approved resolution of issues in Docket No. 011605-EI, both of which are attached to my prefiled testimony.

Q. Did PEF encounter any force majeure events in 2005?

A. Yes, PEF encountered four force majeure events. Tropical Storm Cindy, Hurricane Dennis, Hurricane Katrina and Hurricane Rita entered the Gulf of Mexico and disrupted a portion of our contracted natural gas supplies.

Q. What measures did PEF take during these force majeure events to maintain the load of its customers?

A. As discussed in my testimony of March 1, 2006 related to the 2005 storms, PEF took the following measures to mitigate natural gas supply interruptions during the storm-related force majeure events: 1) purchased replacement supplies, 2) purchased supplies from third party storage accounts, 3) utilized three different 10-day storage daily call options, 4) utilized No. 2 fuel oil to the extent necessary for reliability purposes, and 5) worked with Gulfstream Natural Gas (Gulfstream) and Florida Gas Transmission (FGT) to use excess gas in their pipelines to meet load.

Q. What measures did PEF undertake to minimize other risks identified in its Risk Management Plan?

A. PEF continued to perform its daily management activities outlined in the Plan to monitor and, to the extent possible, mitigate risks to its customers.

Q. Did PEF follow the processes and guidelines outlined in the Plan?

A. Yes, all processes and guidelines were followed.

Q. What hedging activities did PEF undertake for fuel and wholesale power?

A. PEF did not hedge wholesale power for 2005. With regard to coal prices, PEF did secure coal under fixed price term contracts for 2005. PEF did make economic purchases, as well as wholesale power sales to third parties that resulted in overall savings to customers of approximately $46 million. With respect to natural gas, PEF met all of its hedging strategy objectives to: 1) mitigate price risk and volatility, 2) provide gas price certainty, 3) maintain a diverse portfolio, and 4) provide potential for ratepayer savings. To that end, the following transactions were entered into by the Company:

1) PEF had several fixed price contracts that resulted in additional savings to customers of approximately $121.7 million. As of December 31, 2005, these fixed priced contracts had a favorable marked-to-market value through 2010 of approximately $519.7 million.

2) The Company used financial swaps to fix the price on a portion of the residual oil used in 2005 that resulted in a net savings to customers of approximately $70.3 million.

To summarize, PEF met its 2005 hedging objectives including the objective of providing a savings to ratepayers. A total savings to customers of approximately $192 million was attained in addition to approximately $46 million in economic power purchases and excess power generation sales.

Q. Please describe PEF's process for procuring natural gas at market prices.

A. PEF buys virtually all of its term natural gas at market index prices. It purchases most of its gas supply on either a short-term or long-term basis using a Request for Proposal process to identify suppliers that can meet the Company's needs. The resulting contracts identify market indices to establish daily or monthly gas prices. The Company also builds in price flexibility to be able to change a floating market index price to a fixed price for a certain amount of time to implement its phased hedging strategy to reduce price volatility for its ratepayers. Some supplies are purchased at a fixed price initially to hedge physical natural gas to execute PEF's hedging strategy mentioned above. For the most part, natural gas prices are determined by the market index at the location of the PEF's receipt points to its firm transportation capacity. For example, gas purchased at FGT Zone 3 is priced based on either Platts Inside FERC, Gas Market Report, first of the month posting for FGT Zone 3 or Platts Gas Daily, daily price survey midpoint for the day of flow for FGT Zone 3.

Q. Please describe PEF's process for procuring residual oil and distillate oil at market prices.

PEF purchases residual and distillate fuel oil primarily through term contracts. Some supplies are purchased in the spot market to supplement contract supply as needed. Fuel oil prices for the term contracts are generally based on the U.S. Gulf Coast or New York Harbor market index quotes for the particular grade of fuel oil. The delivered price includes charges for transport, handling, inspection and taxes. For spot supplies, the prices are based on either fixed delivered price, market index quotes or supplier rack postings plus transport, handling, inspection and taxes.

Q. Does this conclude your testimony?

A. Yes

MR. BURNETT: Madam Chairman, at this time Mr. Oliver is our only remaining witness. I believe that the only issues that he has that are not stipulated would be the GPIF phase, and so at this time we could move in his, his April 3rd, 2006, testimony and Exhibit 40, those go to stipulated issues, and leave his August 22nd testimony with Exhibits 41 through 43 to remain for the GPIF phase, if that's acceptable.

CHAIRMAN EDGAR: Is there any objection?

MR. McWHIRTER: No questions from FIPUG, ma'am.

CHAIRMAN EDGAR: Okay. Then the prefiled testimony of Witness Oliver filed April 3rd, 2006, and exhibit marked Number 40 will be entered into the record.

(Exhibit 40 marked for identification and admitted into the record.)

PROGRESS ENERGY FLORIDA

DOCKET NO. 060001-EI

GPIF Reward/Penalty Amount for January through December 2005

DIRECT TESTIMONY OF ROBERT M. OLIVER

Q. Please state your name and business address.

A. My name is Robert M. Oliver. My business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601.

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

A. I am employed by Progress Energy Carolinas as Manager of Portfolio Management.

Q. Describe your responsibilities as Manager of Portfolio Management.

A. As Manager of Portfolio Management, I am responsible for managing the development and application of the model, analysis and data used for the short term generation planning. As relates to this process, my duties include responsibility for the preparation of the information and material required by the Commission's GPIF True-Up and Targets mechanisms.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of the Company's GPIF reward/penalty amount for the period of January through December 2005. This calculation was based on a comparison of the actual performance of the Company's nine GPIF generating units for this period against the approved targets set for these units prior to the actual performance period.

Q. Do you have an exhibit to your testimony in this proceeding?

A. Yes, I am sponsoring Exhibit No. ______ (RMO-1T), which consists of the schedules required by the GPIF Implementation Manual to support the development of the incentive amount. This 28-page exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

Q. What GPIF incentive amount have you calculated for this period?

A. I have calculated the Company's GPIF incentive amount to be a penalty of $1,547,048. This amount was developed in a manner consistent with the GPIF Implementation Manual. Page 2 of my exhibit shows the system GPIF points and the corresponding penalty. The summary of weighted incentive points earned by each individual unit can be found on page 4 of my exhibit.

Q. How were the incentive points for equivalent availability and heat rate calculated for the individual GPIF units?

A. The calculation of incentive points was made by comparing the adjusted actual performance data for equivalent availability and heat rate to the target performance indicators for each unit. This comparison is shown on each unit's Generating Performance Incentive Points Table found on pages 9 through 17 of my exhibit.

Q. Why is it necessary to make adjustments to the actual performance data for comparison with the targets?

A. Adjustments to the actual equivalent availability and heat rate data are necessary to allow their comparison with the "target" Point Tables exactly as approved by the Commission prior to the period. These adjustments are described in the Implementation Manual and are further explained by a Staff memorandum, dated October 23, 1981, directed to the GPIF utilities. The adjustments to actual equivalent availability concern primarily the differences between target and actual planned outage hours, and are shown on page 7 of my exhibit. The heat rate adjustments concern the differences between the target and actual Net Output Factor (NOF), and are shown on page 8. The methodology for both the equivalent availability and heat rate adjustments are explained in the Staff memorandum.

Q. Have you provided the as-worked planned outage schedules for the Company's GPIF units to support your adjustments to actual equivalent availability?

A. Yes. Page 27 of my exhibit summarizes the planned outages experienced by the Company's GPIF units during the period. Page 28 presents an as-worked schedule for each individual planned outage.

Q. Does this conclude your testimony?

A. Yes.

MR. BURNETT: Thank you. No further witnesses from Progress Energy Florida.

CHAIRMAN EDGAR: Thank you.

Mr. Beasley.

MR. BEASLEY: Yes, ma'am. We would call Ms. Joann Wehle for Tampa Electric Company.

JOANN WEHLE

was called as a witness on behalf of Tampa Electric Company and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BEASLEY:

Q Would you please state your name, your business address and your, and your employment for the record.

A Yes. My name is Joann Wehle. I am the Director of Wholesale Marketing and Fuels for Tampa Electric Company.

Q Ms. Wehle, you were in the room yesterday when the witnesses were sworn; right?

A That's correct.

Q Okay. Did you prepare and cause to be filed in this proceeding final true-up testimony filed April 3, 2006?

A Yes, I did.

Q Did you also submit projection testimony filed September 1, 2006?

A Yes, I did.

Q If I were to ask you the questions set forth in those testimonies, would your answers be the same?

A Yes, they would.

MR. BEASLEY: I would ask that Ms. Wehle's testimony, both the final true-up and the projection testimony, be inserted into the record as though read.

CHAIRMAN EDGAR: The prefiled testimony will be entered into the record as though read.

MR. BEASLEY: Thank you.

BY MR. BEASLEY:

Q Ms. Wehle, did you also prepare and submit an exhibit JTW-1 filed April 3, 2006, which is marked hearing Exhibit Number 49?

A Yes, I did.

Q Did you also submit Exhibit JTW-2 that accompanied your September 1, 2006, projection testimony?

A Yes, I did.

MR. BEASLEY: And I believe that JTW-2 was not set forth in the comprehensive list of issues of staff, and I would ask that that be marked for identification. And there's -- I think the next blank exhibit number is 56.

CHAIRMAN EDGAR: 56 is the next number on my list. Ms. Bennett.

MS. BENNETT: That is correct, Madam Chair.

CHAIRMAN EDGAR: Okay. The exhibit is so marked.

(Exhibits 49 and 56 marked for identification.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 060001-EI
FILED: 4/3/06

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOANN T. WEHLE

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

A. My name is Joann T. Wehle. 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 the Wholesale Marketing and Fuels Department.

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

A. I received a Bachelor's of Business Administration Degree in Accounting in 1985 from St. Mary's College, South Bend, Indiana. I am a CPA in the State of Florida and worked in several accounting positions prior to joining Tampa Electric. I began my career with Tampa Electric in 1990 as an auditor in the Audit Services Department. I became Senior Contracts Administrator, Fuels in 1995. In 1999, I was promoted to Director, Audit Services and subsequently rejoined the Fuels Department as Director in April 2001. I became Director, Wholesale Marketing and

Fuels in August 2002. I am responsible for managing Tampa Electric's wholesale energy marketing and fuel-related activities.

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 2005 performance 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. In addition, I will present details regarding the appropriateness for recovery of $164,960 in incremental operations and maintenance ("O&M") expenses associated with hedging activities.

Q. Have you prepared any exhibits in support of your testimony?

A. Yes. Exhibit No. ____ (JTW-1) was prepared under my direction and supervision. My exhibit shows Tampa Electric's calculation of its 2005 incremental hedging O&M expenses.

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

A. Unless otherwise indicated, the source of the data is 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 2005?

A. As outlined in Tampa Electric's annual Risk Management Plan most recently filed on September 9, 2005 in Docket No. 050001-EI, the company strives to reduce fuel price volatility while maintaining a reliable supply of fuel. In an effort to limit exposure to market price fluctuations of natural gas, Tampa Electric established a hedging program. The program was updated and approved by the company's Risk Authorizing Committee ("RAC") in November 2005. Tampa Electric currently follows the program as approved by the RAC.

On April 3, 2006 Tampa Electric filed its annual risk management report, which describes the outcomes of its 2005 risk management activities. The report indicates that Tampa Electric's 2005 hedging activities produced a net savings of $58.4 million for its customers.

Q. How did Tampa Electric's fuel mix change in 2005?

A. Tampa Electric's fuel mix remained relatively stable in 2005, with natural gas-fired generation representing more than 43 percent of total retail generation, coal accounting for approximately 56 percent and oil representing less than 1 percent. The company completed the transition from burning predominantly coal to utilizing a mix of natural gas and coal when H. L. Culbreath Bayside ("Bayside") Unit No. 2 became commercially operational on January 15, 2004.

Q. Does Tampa Electric use a hedging information system?

A. Yes, Tampa Electric continues to use Sungard's Nucleus Risk Management System ("Nucleus"). Nucleus records all natural gas hedging transactions and calculates risk management reports common to the industry. In addition, 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 also records all physical natural gas transactions. By consolidating physical transactions and financial natural gas hedging transactions into the Nucleus system Tampa Electric has improved contract, credit management and risk exposure analysis.

Q. What were the results of the company's incremental hedging activities in 2005?

A. Tampa Electric's incremental natural gas hedging activities protected customers from price volatility for [redacted] of the natural gas used in the company's generating stations. The net result of natural gas hedging activity in 2005 was a savings of $53.2 million, when the instrument prices were compared to market prices on settled positions.

Q. Did the company use financial hedges for other commodities in 2005?

A. No, Tampa Electric did not use financial hedges for other commodities because of its fuel mix. Historically, Tampa Electric has primarily relied on coal as a boiler fuel.

The price of coal is relatively stable compared to the prices of oil and natural gas. In addition, there are no financial hedging instruments for the types of coal the company uses. Tampa Electric consumes a small amount of oil, making price hedging somewhat impractical; therefore, the company did not use financial hedges for oil. The company did not use financial hedges for wholesale energy transactions because a liquid, published market does not exist in Florida.

Q. Does Tampa Electric use physical hedges?

A. Yes, Tampa Electric uses physical hedges in managing its coal supply. The company enters into a portfolio of differing term contracts with various suppliers to obtain the types of coal used on its system. In addition, some coal supply contracts contain volume options that the company uses when spot-market pricing is favorable compared to the contract price. In 2005, these coal strategies resulted in gains of $5.2 million, which benefited customers.

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

A. Commission Order No. PSC-02-1484-FOF-EI, in Docket No. 011605 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."

Therefore, Tampa Electric's request for recovery is in accordance with the aforementioned order.

Q. Are you requesting recovery of incremental hedging O&M costs?

A. Yes, Tampa Electric requests recovery of $164,960 that the company incurred as incremental O&M expenses. The Commission, in Order No. PSC-02-1484-FOF-EI, states:

"Each investor-owned electric utility may recover through the fuel and purchased power cost recovery clause prudently-incurred incremental operating and maintenance expenses incurred for the purpose of initiating and/or maintaining a new or expanded non-speculative financial and/or physical hedging program designed to mitigate fuel and purchased power price volatility for its retail customers each year until December 31, 2006 or the time of the utility's next rate proceeding, whichever comes first."

Tampa Electric established its base year expenses according to the portion of the employee's time and related expenses for hedging in 2001. The 2005 actual costs were then calculated using the same methodology. Tampa Electric's calculation of the incremental expenses as well as base year expenses and 2005 actual expenses are shown in my Exhibit No._____ (JTW-1).

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOANN T. WEHLE

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

A. My name is Joann T. Wehle. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Wholesale Marketing & Fuels.

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

A. I received a Bachelor of Business Administration Degree in Accounting in 1985 from St. Mary's College in Notre Dame, Indiana. I am a CPA in the State of Florida and worked in several accounting positions prior to joining Tampa Electric. I began my career with Tampa Electric in 1990 as an auditor in the Audit Services Department. I became Senior Contracts Administrator, Fuels in 1995. In 1999, I was promoted to Director, Audit Services and subsequently rejoined the Fuels Department as Director in April 2001. I became Director, Wholesale Marketing and Fuels in August 2002. I am responsible for managing Tampa Electric's wholesale energy marketing and fuel-related activities.

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 2007 risk management plan submitted concurrently in this docket. Finally, I will present the calculation of waterborne transportation costs submitted for recovery.

Q. Have you previously testified before this Commission?

A. Yes. I testified before this Commission in Docket Nos. 030001-EI and 031033-EI, and I filed testimony in the annual fuel and purchased power cost recovery dockets since 2001. My testimony in these dockets described the appropriateness and prudence of Tampa Electric's fuel procurement activities, fuel supply risk management, fuel price volatility hedging activities, and fuel transportation costs.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes. Exhibit JTW-2 describes the calculation of the 2005 waterborne transportation costs disallowance.

2007 Fuel Mix and Procurement Strategies

Q. What fuels will Tampa Electric's generating stations use in 2007?

A. In 2007, Tampa Electric expects its fuel mix to be nearly the same as 2006. In 2007, natural gas-fired and coal-fired generation is expected to be 42 percent and 57 percent of total generation, respectively. The remaining generation comes from No. 2 oil and No. 6 oil.

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. Tampa Electric uses a portfolio approach to natural gas procurement. The company's portfolio consists of a blend of base load, intermediate and swing supply along with 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 trades for physical natural gas supply with approved counterparties, enhancing liquidity and diversification of its natural gas supply portfolio. The natural gas prices are based on monthly and daily price indexes, increasing portfolio diversification.

Tampa Electric improved reliability 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 minimize costs to its customers. Additionally, Tampa Electric's risk management activities improve the company's natural gas procurement activities by reducing natural gas price volatility.

Q. How has Tampa Electric diversified its natural gas transportation arrangements?

A. As described in my testimony filed on September 9, 2005 in Docket No. 050001-EI, Tampa Electric diversified its transportation assets when it entered into a cost-effective contract for firm natural gas transportation on Gulfstream

Natural Gas Pipeline, LLC ("Gulfstream") that provides firm natural gas transportation directly to Tampa Electric's H. L. Culbreath Bayside Station ("Bayside Station") from Manatee County, via a 28-mile lateral pipeline. Tampa Electric anticipates completion of the lateral pipeline in late 2007 to early 2008. The transportation agreement with Gulfstream adds a second pipeline to Tampa Electric's capacity portfolio and improves the company's ability to meet natural gas hourly and daily demands.

Q. Has Tampa Electric taken any other measures to enhance the reliability of access to natural gas supply?

A. In 2005, Tampa Electric entered into a storage capacity agreement with Bay Gas Storage near Mobile, Alabama. This agreement provided Tampa Electric with 175,000 MMBtu of storage capacity beginning in 2005. The expansion of Bay Gas Storage, expected to be complete during the second quarter of 2007, will increase Tampa Electric's storage capacity to 750,000 MMBtu. In addition to storage, Tampa Electric also diversified its natural gas supply receipt points on Florida Gas Transmission. It "swapped" FGT Zone 3 receipt points with another pipeline customer to acquire their FGT Zone 1 and Zone 2 receipt points. These receipt points reduce the company's vulnerability to hurricane impacts in FGT Zone 3 and provides access to lower priced gas supply.

Q. What is Tampa Electric's coal procurement strategy?

A. Tampa Electric's two coal-fired plants are Big Bend Station and Polk Station. Big Bend Station is a fully scrubbed plant whose design fuel is high-sulfur Illinois Basin coal. Polk Station is an integrated gasification combined cycle plant currently burning a mix of coal, petroleum coke, and lower sulfur coal. The plants have varying operational and environmental restrictions and require fuel with custom quality characteristics such as sulfur content, Btu/lb, ash, fusion temperature and chlorine content. Since coal is not a homogenous product, fuel selection is based on these unique characteristics, price, availability, and creditworthiness of the supplier.

Tampa Electric maintains a portfolio of bilateral, long-, intermediate-, and short-term contracts for coal supply. 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 in market monitoring and in shaping the company's coal procurement strategy to reflect current market conditions. This allows for stable supply sources while providing flexibility to take advantage of favorable spot market opportunities. The company's efforts to obtain the most favorable coal prices directly benefit its customers by displacing higher cost options.

Q. Has Tampa Electric entered into coal and natural gas supply transactions for 2007 and 2008 delivery?

A. Yes, it has. To mitigate price volatility and ensure reliability of supply, Tampa Electric has contracted for a significant portion of its expected coal needs for both years through bilateral agreements with coal suppliers. Nearly two thirds of the company's expected 2007 and 2008 coal requirements are already under contract. Tampa Electric has also entered into contracts for over 40 percent of the company's expected natural gas needs for the winter of 2006 and through 2007.

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 monitors and adjusts fuel volumes it accepts within contractually allowed maximum and minimum amounts in accordance with the price of fuel available on the spot market, to take advantage of the lowest available prices. 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 2007 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 PIRA Energy Consulting, Hill & Associates, the Energy Information Administration, the New York Mercantile Exchange ("NYMEX") and other energy market information sources. Futures prices for energy commodities, as traded on the NYMEX, blended with current PIRA price forecasts form the basis of the natural gas, No. 6 oil, No. 2 oil and propane price forecasts. The commodity price projections are adjusted to incorporate expected transportation costs and quality adjustments. These adjustments are specific to the power plants to which the fuel will be delivered and the locations from which it is transported.

Coal prices and coal transportation prices are projected using information from industry-recognized consultants 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, inventory effects, and analysis performed on coal inventory.

Q. How do the 2007 projected fuel prices compare to the fuel prices projected for 2006?

A. The entire industry, including Tampa Electric, has experienced rising fuel prices since 2003, and projected fuel prices for 2007 are expected to remain high due to the demand on natural resources. The global economy and the increasing industrialization of countries like China have affected the global balance of natural resources such as natural gas, oil, and coal. Additionally, crude oil prices have soared to well over $70 per barrel, due to factors such as the turmoil in the Middle East, fears of additional hurricane activity near the U.S. coastline and growth in demand for refined products. Similarly, the transportation costs for commodities have increased as the fuel used in that transportation increased in price.

Q. What are the market drivers of the expected 2007 increase in the price of natural gas?

A. Of the fuels utilized by Tampa Electric, natural gas has experienced the greatest increase in price over the last several years. In addition to price pressures from crude oil, the market drivers include increased demand from natural-gas fired generation, declining natural gas production in North America, delayed liquefied natural gas projects, concerns about the adequacy of natural gas in storage, and concerns about production losses due to tropical storm activity.

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

A. Coal prices correlate with the prices of other fuels since coal mining utilizes petroleum products, steel, and lumber in its production processes; therefore, coal prices have increased in conjunction with increases in the prices of these products and other fuels. Also, increased costs of SO_2 allowances contributed to the higher prices for lower sulfur coals and coal in general. Thus, Tampa Electric expects higher coal prices to continue through 2006. Fortunately, Tampa Electric's use of high sulfur coal from the Illinois Basin in scrubbed units has shielded Tampa Electric from some of the extreme price volatility experienced in low sulfur coal prices.

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

A. Yes. Tampa Electric estimates that actual prices in 2007 could be higher or lower than the base forecast by as much as 35 percent. Similarly, oil prices may be 25 percent higher or lower than the projected base case. The causes of this uncertainty include weather, political turmoil, global economics, commodity production, and transportation issues.

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 simultaneously in this docket.

Q. Does Tampa Electric's risk management strategy help to mitigate natural gas price risk?

A. Yes. To help protect customers from price volatility, Tampa Electric may purchase over-the-counter natural gas swaps, options and collars. A swap is a financial derivative that provides a "fixed for floating" position. Tampa Electric, the buyer pays a fixed price for the natural gas, which has a floating value until cash settlement. Swaps allow Tampa Electric to lock in known natural gas prices and avoid upward price volatility. The transaction costs of swaps are embedded in the price of the commodity.

Options give Tampa Electric the right, but not the obligation, to buy (call) or sell (put) natural gas at a predetermined price for a given future month. Tampa Electric pays a premium at the time of the option purchase for this right.

Collars are combinations of call options (caps) and put options (floors) that limit prices within a certain range. An option is the right, but not the obligation, to buy (call) or sell (put) natural gas at a pre-determined price. With a collar, the company knows that its future prices will remain within the predetermined boundaries established by the call and put options.

Q. Has Tampa Electric used financial hedging to help mitigate the price volatility of its 2006 and 2007 natural gas requirements?

A. Yes. Tampa Electric has hedged a significant portion of its 2006 natural gas supply needs and a portion of its expected 2007 natural gas supply needs. Tampa Electric will continue to take advantage of available natural gas hedging opportunities that benefit its customers, while complying with the company's approved Risk Management Plan. The current market position for natural gas hedges is provided in the Risk Management Plan.

Q. Are the company's strategies adequate for mitigating price risk for Tampa Electric's 2006 and 2007 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.

Q. Have recent increases in the market price of natural gas affected the percentage of Tampa Electric's natural gas requirements that the company has hedged or plans to hedge?

A. No. The volume hedged is driven primarily by expected natural gas consumption levels and the time until that natural gas is needed. Based on those two parameters, the amount hedged is maintained within a prescribed percentage range. Price is not a component of the current plan since the objective is price volatility reduction, not price speculation.

Q. Were Tampa Electric's efforts through August 2006 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.

Coal Transportation Costs

Q. Did Tampa Electric calculate the waterborne transportation costs submitted for cost recovery in accordance with the Commission's Order No. PSC-04-0999-FOF-EI ("Order No. 04-0999"), issued in Docket No. 031033-EI on October 12, 2004?

A. Yes. The waterborne transportation costs that Tampa Electric is seeking to recover are the adjusted rates per ton for each upriver terminal as well as the adjusted ocean barge transportation rate. The company calculates the adjusted rates as described in Order No. 04-0999. The river rate is adjusted using the following formula:

$$\frac{\text{(Weighted average rate per ton for all upriver terminals - \$1/ton)}}{\text{Weighted average rate per ton for all upriver terminals}} \times \text{Contract rate for specific upriver terminal}$$

The ocean rate is reduced by [redacted] per ton for shipments from the Davant, Louisiana terminal and [redacted] per ton for petroleum coke shipments from Texas, as prescribed by the Commission order.

For 2005, Tampa Electric's adjustment to its total waterborne transportation costs totaled $14,144,718. The variance from the projected $15,315,000 disallowance amount was due to variations in river terminal origins, petroleum coke purchases, and total tons shipped, compared to projections. The total 2005 adjustment recorded in Tampa Electric's final true-up filing, submitted in this docket on March 1, 2006, was calculated using the actual tons of coal and petroleum coke shipped in 2005 and the methodology required by Order No. 04-9999. These calculations are shown in Exhibit JTW-2, Document No. 1. Therefore, Tampa Electric's 2005 adjusted coal transportation costs are appropriate for recovery through the Fuel and Purchased Power Cost Recovery Clause.

Likewise, the expected 2006 and 2007 waterborne transportation costs have been adjusted using this same methodology according to Order No. 04-0999 and will be revised to reflect the actual tons shipped and associated calculated disallowances as part of the normal true-up process. Accordingly, it is also appropriate for Tampa Electric to recover its allowable 2006 and 2007 projected transportation expenses included in the fuel clause for coal transportation.

Q. Does this conclude your testimony?

A. Yes, it does.

BY MR. BEASLEY:

Q Ms. Wehle, would you please summarize your testimony?

A Yes.

Good morning, Commissioners. My name is Joann Wehle. I am the Director of Wholesale Marketing and Fuels for Tampa Electric Company.

My direct testimony addresses a variety of fuel-related issues, including the mitigation of price risk associated with natural gas purchases. As noted in our risk management plan filings with the Commission, our hedging plan approved by the company's Risk Authorizing Committee describes the company's strategies to balance the desire for reduced price volatility and reasonable cost, given somewhat uncertain natural gas volumes.

Tampa Electric's hedging portfolio has provided price stability during times of volatile gas prices. Tampa Electric has consistently applied the plan to our natural gas needs, and in late 2005 increased the length and volumes that can be hedged under the plan. Overall, the plan benefits our customers by limiting exposure to the volatile nature of price swings in the marketplace. This concludes my summary.

MR. BEASLEY: Ms. Wehle is available for questions.

CHAIRMAN EDGAR: Ms. Christensen, do you have questions for this witness on cross?

MS. CHRISTENSEN: No questions for Ms. Wehle.

CHAIRMAN EDGAR: Thank you.

Mr. McWhirter.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Good morning, Ms. Wehle.

A Good morning, Mr. McWhirter.

Q As I understand the testimony that's been filed in this case, Tampa Electric contemplates about a 14 percent increase in its fuel costs for the year 2007?

A Our overall costs, that's correct.

Q Is the overall cost going up because you're buying more natural gas or are you staying pretty much level with the current percentage, which is what, 42 percent?

A That's correct. We, we -- our generation mix is about 42 percent natural gas. The increase in the overall cost also includes underrecoveries besides just the natural gas projections.

Q And your underrecovery for 2006 you contemplate to be $157 million?

A I believe that's correct.

Q And has that underrecovery projection to your knowledge changed any as a result of the reduction in gas costs the last quarter of 2006?

A Again, that is based on our projection filing as of September of this year.

Q Is projection based on September?

A Yes.

Q And you haven't made a projection since that time?

A That is correct.

Q So what you're asking in your $1.177 billion fuel cost this year will be $157 million for anticipated underrecoveries in 2006, plus your estimate that gas prices will remain the same during 2007 as they did -- as they were when you made your projection in early September?

A That is correct.

Q And you anticipated, according to Mr. Aldazabal's testimony, that for the year 2007 the natural gas price would average out at $10 per MMBtu or MCF?

A If you could point me to where you're getting that $10 figure, sir.

Q Beg your pardon?

A Could you point me to where you're getting that $10 figure?

Q Yes. It's in Schedule E3 of Mr. Aldazabal's testimony, Page 27. Y'all Bate stamp your pages and that's good.

A The total natural gas projection, including the commodity as well as the transportation, is $9.73 in MMBtu in our filing.

Q And so look up a little bit further and you anticipate that you will spend $584 million on natural gas because you expect that you're going to pay on average $10 in MCF for that gas throughout 2007; is that right?

A That's an approximation, sir. That's correct.

Q And did you hear what Mr. Portuondo said with respect to the ongoing obligation to come in even up to the last day and change your fuel projections if it appears there are dramatic changes in the market?

A I did hear what Mr. Portuondo said.

Q Do you agree with that --

A Again, I think what he said was if there were material changes, that the utilities have the opportunity to reproject if the changes were materially different than the current marketplace. We -- our filing, we do not feel that there were material changes based on the forward price of natural gas as well as our fuel mix that would require us to come in and actually file a new projection.

Q I deposed you earlier, and I believe that deposition is going to be in the record in the staff's filing, so I'm not going to ask you a lot of the questions that were in that. Thankfully, huh?

But like Mr. Portuondo's company, you don't deal in the NYMEX. You deal in one-on-one over-the-counter transactions.

A That is correct.

Q And do you pay -- hedging to me is like insurance, and I think -- that may be a bad analogy. But when you buy insurance, you're insuring against a risk, and when you hedge, you're dealing with a risk. And with insurance we pay a premium. Do you pay a premium, a risk premium when you hedge your cost with banks?

A That would depend on the type of instrument that you're actually using to hedge. There are instruments that have specific premiums associated with them. Others, such as swaps, which is what we actually enter into on the financial derivative contracts, have embedded within them basically brokerage or commission fees.

Q And are you able to quantify what that commission or brokerage fee is?

A Over time it really changes. It can be anywhere from, you know, 5 to 10 cents and upwards from there, again, depending on the volatile nature of the market.

Q 5 and 10 cents per --

A Per MCF.

Q Per MCF?

A Yes.

Q Uh-huh. Which at a $10 price would be what, 1 percent of the --

A That's correct.

Q Uh-huh. And does the percentage vary over time?

A It will vary based on, again, the volatile nature of the market.

Q Uh-huh. Do you have -- can you tell us what you have paid in commissions and transaction fees and risk premiums for the year 2006 to date?

A That would be very difficult to estimate since, again, those costs are embedded in the actual cost of the instrument.

Q Uh-huh.

A However, we have not engaged in financial derivative contracts that require premiums up-front.

Q As I understand your program, is it confidential or not confidential the period of time which you go out into the future with your hedging contracts?

A That is, excuse me, that is not confidential. Our program covers a 24-month period.

Q And within that 24-month period you have minimum hedges and maximum hedges?

A Within that 24-month period we have a variety of minimum and maximum levels, if you will.

Q Is it confidential or not to tell us how you utilize these minimums and maximums during -- as you do look into the future with respect to how much you're going to hedge within the percentage limitation?

A That information is confidential.

Q I see. Do you give the percentage that has been hedged after the fact like Florida Progress does, or is it secret information or confidential information forever?

A I believe in our risk management plan filings that we prepare and provide to the Commission staff every April we provide a summary by month. And then while those, those individual months may be confidential, the actual totals of percentage hedged and gains and losses are, are actually not deemed confidential.

Q I see. Do you know what your gains or losses are for the year 2006 to date?

A Our gains through September of this year have -- excuse me. Our losses through September of this year have been roughly $34 million.

Q And that's part of the $157 million that you anticipate to be your underrecovery carried forward?

A Again, that's through September, September 30th. Whether or not, you know, the components relating to August and September were actually included in the filing, I'm not really sure. But certainly through July I would imagine that the losses that were realized through midsummer have been included in the filing.

Q The other people who've testified say they do not engage in speculative hedging. How do you characterize -- what does that term mean to you?

A Well, we had some guidance from the staff when the actual hedging docket was initiated, and their view of what speculation is is actually participating in hedging practices that exceed your volumes certainly for what your particular, in our case, gas needs would be.

You could take it into a whole variety of different realms. I mean, certainly speculating could be gauging or trying to beat the market could be considered speculating. And that's not what our program does.

Q What does your -- if you were going to gauge the success or failure of your program, what criteria would you use to gauge success or failure?

A What we use to gauge the success or failure of our program is if it's meeting its stated objectives, and those objectives are to limit the price volatility of natural gas for our customers. And that's why we think our program is successful.

Q You could pay $5 more than the market price over a period of time and that would eliminate volatility probably. But would you perceive that to be a reasonable action to take?

A Again, when you say you could pay $5 more than the market, I'm not sure anybody would enter into an agreement or a derivative that would pay $5 more than the current market at the time.

You would have to take each and every one of those circumstances on its own merits and what you knew at the time and what the circumstances were at the time when you entered into hedges.

Q The -- are the names of the counterparties that you enter into transactions with confidential?

A I don't believe that they are.

Q Okay. Can you tell me who TGP&A is?

A No, sir.

Q Can you tell me who MSCG is?

A If you could tell me where you're getting this information, I might be able to shed some more light on it.

Q I'm getting it from the response you gave to FIPUG's Interrogatory Number 4.

A Okay.

Q It was on a CD, so it may not be in the papers you have.

A Actually I'm looking at Interrogatory Number 4 and it, it didn't request any of that information, sir.

Q It what?

A It talked about definitions of budget and hedge price and settle price.

Q Okay. I got a CD that said "Response to FIPUG Number 4," and in that CD it had acronyms for your counterparties.

A I'm looking at Number 4, sir.

Maybe what I can shed a little bit of light on is perhaps some of the types of counterparties we deal with rather than specific acronyms.

Q All right.

A Okay? I think similar to what you've heard from some of the other witnesses we do have over-the-counter derivative type contracts with a variety of financial institutions like Credit Suisse, Merrill Lynch, Morgan Stanley, you know.

Q Barclays and Mitsui, I got those.

A Barclays and Mitsui, yes. Correct.

Q BP&A, what is that?

A That's the name of the organization.

Q UBS, that's --

A UBS. Uh-huh.

Q That's an investment banking firm.

A That's correct.

Q Do these financial institutions have any dealings with your parent corporation or with any of the affiliated companies to Tampa Electric?

A I don't know the answer to that question.

Q In your hedging program do you deal with any affiliates of Tampa Electric?

A I don't understand your question. What do you mean "deal with"?

Q Do you buy and sell or enter into swaps or options or call agreements with any of the affiliates of Tampa Electric

Company?

A No, we do not.

Q And your hedging program is linked with that of People's Gas or TECO People's Gas?

A It is not linked. It's a separate program.

Q In your risk management program you use the phrase that one of the things you try to do is increase reliability. And transactions with these financial institutions, that does haven't anything to do with reliability, does it?

A No, it does not. I think what we were referring to there were some of the physical hedges or physical contracts for coal that we actually purchase.

Q Okay. As long as I've known anything about Tampa Electric Company, you've entered into long-term contracts with coal companies to acquire coal; is that correct?

A We've entered into long-term, medium-term and spot contracts for coal delivery.

Q And are those now called hedges as opposed to long-term, spot and medium-term contracts that they used to be called?

A You can, you can certainly call them hedges because they are, they do have a fixed component, a fixed price component to them.

Q Do you call them hedges in your hedging program?

A We do.

Q So you're doing the same thing that Tampa Electric has done for decades with respect to coal, but you now call it hedging; is that the deal?

A Yes, we are. And, again, the difference is financial versus physical.

Q Now Mr. Portuondo told us that what they do is they'll enter into supply, a long-term supply agreement with a supplier to guarantee delivery of the commodities. But a lot of those contracts have floating prices based upon a spot market index. Is that the way you do it or do you do something else?

A We actually have some very similar type of contracts.

Q What percentage of your coal contracts are long-term fixed as opposed to contracts that float with the spot market?

A All of our, our coal contracts have a fixed pricing mechanism associated with them. The difference is they may actually have some true-up mechanisms associated with them such as Btu adjustments or, you know, diesel fuel adjustments that vary with the marketplace. However, none of them are based on true coal spot market pricing.

Q Well, I'm trying to differentiate between contracts where the price is relatively fixed that we would call physical hedges and contracts where the price floats based on a number of conditions as you've enumerated and to see what percentage you have fixed and what percentage are the floating type.

A For coal contracts, in that definition I would call them all fixed.

Q All right. The NYMEX requires security deposits in connection with transactions based on certain criteria. Do your counterparties require the same kind of thing?

A Our risk management department goes over credit provisions with our counterparties and determines what credit limits they provide to us and equally we provide to them.

To my knowledge we have not entered into any kind of security deposits with any arrangements.

Q You have -- I think we figured out you have minimum and maximum percentages. Do you have a fixed budget that you move from the minimum to the maximum over a period of time irrespective of the price to insure a lack of volatility, or do you look at the market conditions and come in and out of the market as it looks like a good thing to do?

A We have some flexibility in our minimum and maximum percentages to understand where the marketplace is going, but it is limited. Our program is a very structured and managed program similar to what Florida Power & Light and Florida -- Progress Energy, excuse me, has talked about. We, we execute with some certainty in the marketplace. We do try to take advantage of dips in the market when those are available within our minimum and maximum ranges.

Q On the basis of relative importance, how much do market fluctuations come into play in your trading plans as opposed to the other criteria?

A Our, our importance is looking at where we are on a hedged percentage. That's our most important factor. And I would say secondarily we certainly look at what the marketplace is doing. Similar to what Mr. Yupp had said yesterday, you know, we look at it like we don't -- we can't predict what fuel prices are going to be necessarily in the future. Certainly in our forecast we do the best we can with the information at the time. However, we feel like our program is a very managed and disciplined approach to layering hedges on a dollar cost averaging basis over time.

Q Does your fuel filing this year for 2007 have in it incremental fuel costs, operating, O&M costs that relate to your hedging activities?

A For 2007?

Q Yes, ma'am.

A No, it does not.

Q You anticipated in your testimony that the gas prices when you made your forecast in September, you thought they might change up or down as much as 35 percent. Is that -- for the year 2007 do you still hold by that analysis?

A Yes. That's correct.

Q You anticipate that you'll spend $584,000,000 on natural gas cost at $10 in MCF. So if the price went up

30 percent on your natural gas prices, would that increase your overall fuel cost by more than $177 million?

A Actually, given the fact that we would have hedges in place, it would limit that increase.

Q I see. So you don't anticipate that they'll go more than 30 percent over the $10 number because the $10 number has hedging costs in it?

A That's correct.

Q I see. So then it would be highly unlikely in 2007 that, in your opinion that you would need to come in for a midcourse correction based on current analysis?

A Again, I think that would be speculating. I'm not going to say whether it would be likely or unlikely, sir. It depends on the marketplace. I mean, it goes, it goes to more than just the price of natural gas.

Q What else?

A Well, certainly the entire fuel equation, revenues and price of purchased power and the like. It would be difficult for me to say whether we'd be coming in for a midcourse correction in 2007 or not.

Q Purchased power -- you've got a lot of industrial cogenerators in your service area, don't you?

A We have some, yes.

Q Have you made an effort in your department to see if you could lock up some cogeneration power to perhaps reduce your overall fuel costs?

A Sir, I'm not the appropriate person to answer that question.

Q Who does that?

A We, we, we have some retail marketing or wholesale marketing folks that work on that who would be better posed to actually answer those questions.

Q Well, who does the purchasing from other utilities? Is that your department or some other department?

A That's correct. That's correct.

Q Your department does purchasing from utilities but another department does purchasing from QFs?

A We do it as a joint effort with another department.

Q Uh-huh. And the other department is what?

A It's another marketing function within the corporation.

Q What is the department called?

A I don't recall the exact name of the department.

Q All right. And did you tell me what you have paid so far this year in risk premiums for your hedging activity?

A We have not paid risk premiums this year.

Q You paid an unquantifiable amount than what the banks charge for --

A For entering into swap arrangements, that's correct.

Q And as a final question, define a swap.

A A swap is a financial derivative contract where you enter into a fixed price for settlement at a later date, at which time the parties will either -- will exchange the monetary value of that settlement price. Either it would be a gain or a loss to either party.

Q Second supplemental final question.

A Okay.

Q How does that differ from a call option?

A A call option could be a, if you will, a ceiling that's set up where the, the counterparty purchasing the call option has the ability to float up until that ceiling point. And that's what they're actually protecting themselves against is going above that ceiling price.

Q And you don't do that?

A We have not entered into those for 2006 or 2007.

MR. McWHIRTER: I tender the witness, Madam Chairman.

CHAIRMAN EDGAR: Thank you.

Any questions on cross for this witness by other parties? Seeing none. Questions from staff?

MS. BENNETT: Just one.

CROSS EXAMINATION

BY MS. BENNETT:

Q There's no incremental hedging or O&M expenses in your projection filing for 2007; is that correct?

A That's correct.

Q And, I'm sorry, that was two questions. Why is that?

A As, as we read the, the proposed or the resolution to the hedging docket, our interpretation is that if you do not have a rate case proceeding, the five-year window expires at the end of 2006. And, therefore, since we did not have a rate case proceeding, our ability to seek O&M expenses ends at the end of 2006.

MS. BENNETT: I have no further questions.

CHAIRMAN EDGAR: Commissioners?

Mr. Beasley.

MR. BEASLEY: We have no redirect. And I would like to move the admission of Exhibits 49 and 56.

CHAIRMAN EDGAR: The exhibits will be entered into the record.

(Exhibits 49 and 56 admitted into the record.)

MR. BEASLEY: And ask that Ms. Wehle be excused.

CHAIRMAN EDGAR: You may be excused. Thank you.

MR. BEASLEY: Our next witness on the list, Mr. Benjamin Smith, has been excused. And I would just like to reconfirm that his testimony is inserted into the record as though read.

CHAIRMAN EDGAR: And for double confirmation, clarification, the prefiled testimony of Witness Smith is entered into the record.

TAMPA ELECTRIC COMPANY
DOCKET NO. 060001-EI
FILED: 09/01/06

BEFORE THE PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH

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

A. My name is Benjamin F. Smith. 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 and Fuels 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. 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 marketing. I am currently the Manager of Wholesale Power in the

Wholesale Marketing and Fuels group. My responsibilities are to evaluate, pursue, and negotiate short-term purchase and sale opportunities within the wholesale power market. 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 this Commission?

A. Yes. I testified before this Commission in Docket Nos. 030001-EI and 040001-EI regarding the appropriateness and prudence of Tampa Electric's wholesale purchases and sales. I also submitted written testimony for Docket No. 050001-EI.

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 by analyzing the expected available amounts of generation and the power required to meet the projected customer energy and demand. When there is a need, the company aggressively shops for wholesale capacity and/or energy by searching for reliable supplies at the best possible price from creditworthy counterparties. The company has wholesale power purchase and sales transaction enabling agreements with numerous counterparties. Before engaging in an energy transaction, the company evaluates the creditworthiness of the counterparty.

Purchases are made to achieve reserve margin requirements, to meet customers' needs, to supplement generation during unit outages, and for economical purposes. This process helps minimize the cost of purchased power and maximize the savings to customers.

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. In addition, the company actively manages its wholesale sales and purchases with the goal of capitalizing on opportunities to reduce costs to its customers.

The company's wholesale purchase and sales activities and transactions are reviewed and audited on a recurring basis by the Commission. In addition, Tampa Electric 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. Tampa Electric continually strives to improve its knowledge of markets and the available opportunities 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.

Q. Please describe Tampa Electric's 2006 wholesale energy purchases.

A. Tampa Electric assessed the wholesale energy market and entered into long- and short-term purchases based on price and availability of supply. Approximately 12 percent of the expected energy needs for 2006 will be met using purchased power, which includes economy purchases, the existing firm purchased power agreements with Hardee Power Partners and qualifying facilities, a Calpine 170 MW peaking purchase and a Progress Energy Florida 50 MW system average purchase. The company's purchases also include a 100 MW short-term firm purchase from Cargill for the period of June through August 2006.

The 170 MW purchase from Calpine began May 2006 and continues through April 2011. As included in my September 2005 testimony and approved by the Commission in Docket No. 050001-EI, this purchase is from Calpine's natural gas-fired facilities in Auburndale, Florida and was entered into to meet Tampa Electric's peaking system needs. The 50 MW purchase from Progress Energy began

January 2006 and continues through March 2007. It is a firm purchase with a fuel charge equal to Progress Energy Florida's system average fuel cost. Its estimated savings to customers is projected to be $3.9 million for 2006. The 100 MW purchase from Cargill began June 2006 and continues through August 2006. It is a firm, fixed-price must-take purchase with an estimated customer savings of $1.1 million. All of these purchases provide both supply reliability and help reduce price volatility.

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. Please describe Tampa Electric's 2007 wholesale energy purchases.

A. At this time, with the exception of existing purchases, Tampa Electric has not entered into any agreements with other entities for forward purchases beyond 2006. As previously stated, Tampa Electric continues to evaluate economic combinations of forward purchases to reduce the overall cost to customers as well as make reliability purchases whenever necessary.

For 2007, the company expects to meet approximately 13 percent of its customers' energy needs through purchased power, which includes economy purchases, the existing firm purchased power agreements with Hardee Power Partners, qualifying facilities and 170 MW Calpine purchase as well as a 50 MW purchase from Progress Energy Florida.

Q. Does Tampa Electric plan to enter into any other new purchased power agreements during its upcoming Big Bend Station SCR installation outages?

A. For the upcoming seasonal Big Bend Station SCR installation outages, beginning February 2007, Tampa Electric is monitoring the marketplace for purchase power opportunities. The company will evaluate economic combinations of forward purchases during the outages to reduce the overall cost to customers.

Q. Did the 2004 and 2005 hurricane seasons affect Tampa Electric's 2006 purchased power procurement strategies?

A. Yes, they did. Prior to these hurricanes, it was part of Tampa Electric's risk management strategy to monitor storm activity using available storm tracking resources and evaluate the impact of the storm on the wholesale market and purchase power on the forward market, first for reliability then for economics. In addition to the price of power, the company evaluated important storm-related aspects of these purchases such as geographic location and transmission availability. Because of the 2004 and 2005 hurricane seasons the company increased its focus on fuel-diversified purchases during hurricanes and performs a detailed review of the seller's fuel source and dual-fuel capability. Absent the threat of a hurricane and for all other months of the year, the company's purchased power strategy for evaluating economic combinations of long- and short-term purchase options remains unchanged.

Q. Please describe Tampa Electric's wholesale energy sales for 2006.

A. Tampa Electric entered into various non-firm, non-separated wholesale sales in 2006. Included in these sales is a sale to New Smyrna Beach from January 2006 to December 2006. This sale is a call option for up to 40

MW and provides a projected net benefit to customers of $2.4 million.

The gains from the non-separated sales are returned to customers through the fuel adjustment clause, up to the three-year rolling average threshold of $1,037,634.

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 products and considers such products to be physical hedges. The company has engaged only in physical hedging for wholesale transactions because the availability of financial instruments within Florida is limited. The Florida market currently operates through bilateral contracts between various counterparties, and there is no Florida trading hub where standard financial transactions can occur with enough volume for 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 but instead, employs a diversified power supply strategy, which includes self-generation and long- and short-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 2006?

A. Yes, Tampa Electric's expects its physical hedges to continue to reduce its customers' purchased power price risk. For example, during the summer of 2005, Tampa Electric executed agreements with Okeelanta and Reliant Energy. The Okeelanta purchase was a fixed price agreement and the purchase from Reliant Energy was a cost-based call option on peaking power. Both of these agreements reduce the purchased power price risk for Tampa Electric customers.

The recent Calpine, Progress Energy and Cargill purchases serve as both a physical hedge and reliable source of economical power in 2006. The availability of these purchases is high and their price structures provide some protection from rising market prices, which are largely influenced by the volatility of natural gas prices.

Mitigating price risk is a dynamic process, and Tampa Electric continually re-evaluates its options in light of changing circumstances and new opportunities. As far as purchased power is concerned, Tampa Electric continually strives to maintain an optimum level and mix of long- and short-term capacity and energy purchases to augment the company's own generation.

Q. Please summarize your testimony.

A. Tampa Electric monitors and assesses the wholesale energy market to identify and take advantage of opportunities in the wholesale electric power market, and those efforts benefit the company's customers. Tampa Electric's energy supply strategy includes self-generation and long- and short-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, and enters into wholesale sales that benefit customers. Tampa Electric does not purchase wholesale energy derivatives in the developing Florida wholesale electric 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.

(Transcript continues in sequence with Volume 4.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, CRR, RPR, 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 7TH DAY OF NOVEMBER, 2006.

Linda Boles

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