BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 100001-EI

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR.
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VOLUME 2

Pages 145 through 375

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PROCEEDINGS:	HEARING
COMMISSIONERS PARTICIPATING:	CHAIRMAN ART GRAHAM COMMISSIONER LISA POLAK EDGAR COMMISSIONER NATHAN A. SKOP COMMISSIONER RONALD A. BRISÉ
DATE:	Monday, November 1, 2010
TIME:	Commenced at 1:02 p.m. Concluded at 2:47 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	LINDA BOLES, RPR, CRR Official FPSC Reporter (850) 413-6732
APPEARANCES:	(As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

P R O C E E D I N G S

(Transcript follows in sequence from Volume 1.)

CHAIRMAN GRAHAM: If we can take our seats, we're about ready. I think we left off getting ready to get started with Gulf. So, Mr. Badders.

MR. BADDERS: Yes. Good afternoon, Mr. Chairman. Our first witness is Mr. Ball. And I will note for the record that he was present this morning and he was sworn in.

CHAIRMAN GRAHAM: Welcome, Mr. Ball.

MR. BADDERS: We're ready to proceed.

H. R. BALL

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

DIRECT EXAMINATION

BY MR. BADDERS:

Q Mr. Ball, could you please state your full name and your business address for the record.

A Herbert Russell Ball, One Energy Place, Pensacola, Florida.

Q And what is your current job?

A I'm the Field Manager for Gulf Power Company.

Q Are you the same H. R. Ball who prefiled true-up testimony, estimated actual true-up testimony and projection testimony in this docket?

A Yes.

Q Do you have any changes or corrections to any of that testimony?

A No.

Q If I were to ask you the same questions today, would your answers be the same?

A Yes.

MR. BADDERS: We'd ask that the prefiled direct testimony of Mr. Ball be entered, inserted into the record as though read.

CHAIRMAN GRAHAM: For the record, we'll make sure that Mr. Ball's prefiled testimony will been entered into the record as though read.

BY MR. BADDERS:

Q Mr. Ball, do you also have four exhibits to your testimony?

A Yes, I do.

MR. BADDERS: I will note for the record that those have been identified as hearing Exhibits 15, 16, 17 and 18.

CHAIRMAN GRAHAM: I'm sorry. One more time.

MR. BADDERS: Those would be Exhibits 15, 16, 17 and 18.

CHAIRMAN GRAHAM: Okay.

MR. BADDERS: I'd also note that Exhibit 18 is a confidential exhibit, which we do have copies of for the Commissioners.

BY MR. BADDERS:

Q Do you have any changes to any of those exhibits?

A No, I don't.

GULF POWER COMPANY

Before the Florida Public Service Commission

Prepared Direct Testimony and Exhibits of

H. R. Ball

Docket No. 100001-EI

Date of Filing: March 12, 2010

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

A. My name is Herbert Russell Ball. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Fuel Manager for Gulf Power Company.

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

A. I graduated from the University of Southern Mississippi in 1978 with a Bachelor of Science Degree (Chemistry major) and again in 1988 with a Masters of Business Administration. My employment with the Southern Company began in 1978 at Mississippi Power Company (MPC) at Plant Daniel as a Plant Chemist. In 1982, I transferred to MPC's Corporate Office and worked in the Fuel Department as a Fuel Business Analyst. In 1987 I was promoted and returned to Plant Daniel as the Supervisor of Chemistry and Regulatory Compliance. In 1998 I transferred to Southern Company Services, Inc. in Birmingham, Alabama and took the position of Supervisor of Coal Logistics. My responsibilities included administering coal supply and transportation agreements and managing the coal inventory program for the Southern Electric System. I transferred to my current position as Fuel Manager for Gulf Power Company in 2003.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. My responsibilities include the management of the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost. I also have responsibility for the administration of Gulf's participation in the Intercompany Interchange Contract (IIC) between Gulf and the other operating companies in the Southern Electric System (SES).

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

A. The purpose of my testimony is to summarize Gulf Power Company's fuel expenses, net power transaction expense, and purchased power capacity costs, and to certify that these expenses were properly incurred during the period January 1, 2009 through December 31, 2009. Also, it is my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel expenses.

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

A. Yes, I have.

Counsel: We ask that Mr. Ball's exhibit consisting of five schedules be marked as Exhibit No. _____(HRB-1).

Q. During the period January 2009 through December 2009, how did Gulf Power Company's recoverable total fuel and net power transaction expenses compare with the projected expenses?

A. Gulf's recoverable total fuel cost and net power transaction expense was $545,969,072, which is $11,733,028 or 2.10% below the projected amount of $557,702,100. The lower total fuel and net power transaction expense is attributed to a lower fuel cost of net generation than projected due to lower costs for natural gas for the period. The actual total cost of generated power was below projections by $176,826,569, or 24.62%. The total net cost of purchased power and power sales was above projections due to a $19,507,382, or 42.33% increase in purchased power costs and a $145,586,159, or 70.48% decrease in power sales revenues. Actual net power transaction energy was 11,957,354,968 KWH compared to the projected net energy of 12,610,912,100 KWH or 5.18% below projections. The resulting actual average cost of 4.5660 cents per KWH was 3.25% above the projected cost of 4.4224 cents per KWH. This information is from Schedule A-1, period-to-date, for the month of December 2009 included in Appendix 1 of Witness Dodd's exhibit.

Q. During the period January 2009 through December 2009, how did Gulf Power Company's recoverable fuel cost of net generation compare with the projected expenses?

A. Gulf's recoverable fuel cost of net generation was $489,783,268 or 29.89% below the projected amount of $698,565,100. Actual generation was 12,668,558,000 KWH compared to the projected generation of 16,093,846,100 KWH, or 21.28% below projections. The resulting actual average fuel cost of 3.8661 cents per KWH was 10.93% below the projected fuel cost of 4.3406 cents per KWH. The lower total fuel expense is attributed to a lower quantity of fuel burned than projected for the period. The actual quantity of fuel consumed was 121,100,845 MMBTU which was 22.99% below the projected quantity of 157,251,870 MMBTU. The percentage of energy generated from lower-cost natural gas fired resources was 31.12%, which was 78.24% higher than the projected percentage of 17.46%. The weighted average fuel cost for gas was $4.86 per MMBTU, which is 44.20% below the projected cost of $8.71 per MMBTU. The weighted average fuel cost for coal, plus lighter fuel, was $3.79 per MMBTU, which is 0.52% lower than projected cost of $3.81 per MMBTU. The fuel cost of generation (cents/KWH) was 10.83% lower than projected for the period due to the higher percentage of generation from natural gas fired resources combined with the lower weighted average cost for gas. This information is found on Schedule A-3, period-to-date, for the month of December 2009 included in Appendix 1 of Witness Dodd's exhibit.

Q. How did the total projected cost of coal purchased compare with the actual cost?

A. The total actual cost of coal purchased (excluding Plant Scherer) was $342,993,953 (line 17 of Schedule A-5, period-to-date, for December 2009) compared to the projected cost of $456,344,614 or 24.84% below the projected amount. The lower coal cost was due to a lower weighted average coal price and a lower total quantity of coal purchased for the period. The actual weighted average price of coal purchased was $94.81 per ton which is 2.19% below the projected amount of $96.93 per ton. The lower weighted average price of coal for the period was due to a change in the mix of coal purchases during the period. The total cost of coal purchased at Plant Scherer was $31,187,093 (line 30 of Schedule A-5, period-to-date, for December 2009). This is 2.47% lower than the projection of $31,978,510. The lower coal cost was due to lower quantity of coal purchased for the period. The actual weighted average price of coal purchased was $2.12 per MMBTU which is equal to the projected amount of $2.12 per MMBTU.

Q How did the total projected cost of coal burned compare to the actual cost?

A. The total cost of coal burned (excluding Plant Scherer) was $319,741,817 (line 21 of Schedule A-5, period-to-date, for December 2009). This is 34.46% lower than the projection of $487,881,480. The lower total coal cost was due to a smaller quantity of coal burned (34.83% below projections). This was offset by a slightly higher weighted average coal burn cost (0.57% above projections) for the period. The total cost of coal burned at Plant Scherer was $34,390,920 (line 34 of Schedule A-5, period-to-date, for December 2009). This is 4.87% lower than our projection of $36,152,436. The lower coal burn cost at Scherer was due to a smaller quantity of coal burned (4.40% below projections) and a slightly lower price per MMBTU of coal burn (0.47% below projections).

Q. How did the total projected cost of natural gas burned compare to the actual cost?

A. The total actual cost of natural gas burned for generation was $131,827,795 (line 47 of Schedule A-5, period-to-date, for December 2009). This is 21.29% below the projection of $167,492,450. The decrease can be attributed to lower than forecasted market prices for natural gas on a weighted average basis. The actual weighted average gas burn cost was $4.85 per MMBTU, which is 44.32% lower than the projected burn cost of $8.71 per MMBTU.

Q. Did fuel procurement activity during the period in question follow Gulf Power's Risk Management Plan for Fuel Procurement?

A. Yes. Gulf Power's fuel strategy in 2009 complied with the Risk Management Plan filed on September 2, 2008.

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in a reliable supply of coal being delivered to Gulf's coal-fired generating units during the period?

A. Yes. The supply of coal and associated transportation to Gulf's generating plants was secured through a combination of long-term contracts and spot agreements as specified in the plan. These supply and transportation agreements included a number of purchase commitments initiated prior to the beginning of the period. These early purchase commitments and the planned diversity of fuel suppliers are designed to provide a more reliable source of coal to the generating plants. The result was that Gulf's coal-fired generating units had an adequate supply of fuel available at all times at a reasonable cost to meet the electric generation demands of its customers.

Q. For coal shipments during the period, what percentage was purchased on the spot market and what percentage was purchased using longer-term contracts?

A. Excluding Plant Scherer Unit 3, total coal shipments for the period amounted to 3,910,036 tons. Gulf purchased 105,493 tons or 3% of this coal on the spot market. Spot purchases are classified as coal purchase agreements with terms of one year or less. Spot coal purchases are necessary to allow a portion of the purchase quantity commitments to be adjusted in response to changes in coal burn that may occur during the year. The very small amount of spot coal purchases for the period was the result of coal burn (tons) being 35% lower than projected during 2009. Natural gas prices were lower than projected and the low cost of gas fired generation allowed Gulf to shift generation from coal fired units to natural gas fired units. Gas fired generation was 40.33% above projections and coal fired generation, excluding Scherer, was 38.96% below projections for the period. Gulf shipped 3,804,543 tons or 97% of this coal under longer-term contracts. Longer-term contracts provide a reliable base quantity of coal to Gulf's generating units with firm pricing terms. This limits price volatility and increases coal supply consistency over the term of the agreements. Schedule 1 of my exhibit consists of a list of contract and spot coal purchases for the period.

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in stable coal prices for the period?

A. Yes. Coal cost volatility was mitigated through compliance with the Risk Management Plan. Gulf uses physical hedges to reduce price volatility in the coal procurement program. Gulf purchases coal and associated transportation at market price through the process of either issuing formal requests for proposals to market participants or occasionally for small quantity spot purchases through informal proposals. Once these confidential bids are received, they are evaluated against other similar proposals using standard contract terms and conditions. The least cost acceptable alternatives are selected and firm purchase agreements are negotiated with the successful bidders. Gulf purchased coal and coal transportation using a combination of firm price contracts and purchase orders that either fix the price for the period or escalate the price using a combination of government published economic indices. Schedule 2 of my exhibit provides a list of the contract and spot coal purchases for the period and the weighted average price of shipments under each purchase agreement in $/MMBTU. Because of the fixed price nature of longer term contract coal purchase agreements and the substantial amount of coal under firm commitments prior to the beginning of the period, there was only a small variance between the estimated purchase price of contract coal and the actual price for the period.

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in a reliable supply of natural gas being delivered to Gulf's gas-fired generating units at a reasonable price during the period?

A. Yes. The supply of natural gas and associated transportation to Gulf's generating plants was secured through a combination of long-term purchase contracts and daily gas purchases as specified in the plan. These supply and transportation agreements included a number of purchase commitments initiated prior to the beginning of the period. These natural gas purchase agreements price the supply of gas at market price as defined by published market indices. Schedule 3 of my exhibit compares the actual monthly weighted average purchase price of natural gas delivered to Gulf's generating units to a market price based on the daily Florida Gas Transmission Zone 3 published market price plus an estimated gas storage and transportation rate based on the actual cost of gas storage and transportation Gulf paid during the period. The purpose of early natural gas procurement commitments, the planned diversity of natural gas suppliers, and providing gas suppliers with market pricing is to provide a more reliable source of gas to Gulf's generating units. The result was that Gulf's gas-fired generating units had an adequate supply of fuel available at all times at a reasonable price to meet the electric generation demands of its customers.

Q. Did implementation of the Risk Management Plan for Fuel Procurement result in lower volatility of natural gas prices for the period?

A. Yes. Gulf purchases physical natural gas requirements at market prices and swaps these market prices for firm prices using financial hedges. The objective of the financial hedging program is to reduce upside price risk to Gulf's customers in a volatile price market for natural gas. In 2009, Gulf's weighted average cost of natural gas purchases for generation was $4.83 per MMBTU. This was 44.55% lower than the projection of $8.71 per MMBTU (line 42 of Schedule A-5, period-to-date, for December 2009). Gulf was able to hold per unit fuel costs to very reasonable levels for its customers by following its Fuel Risk Management Plan. The volatility of Gulf's natural gas cost has been reduced by utilizing financial hedging as described in the Fuel Risk Management Plan. As shown on Schedule 4 of my exhibit, the volatility of Gulf's delivered cost of natural gas over the past four-year period as measured by standard deviation was 2.46. The volatility of Gulf's hedged delivered cost of natural gas over the same four-year period as measured by standard deviation was 1.90. Therefore, the financial hedging program is achieving the goal of reducing the volatility of natural gas cost to the customer.

Q. For the period in question, what volume of natural gas was actually hedged using a fixed price contract or instrument?

A. Gulf Power hedged 10,030,000 MMBTU of natural gas in 2009 using fixed-price financial hedges. This represents 52% of Gulf's 19,211,173 MMBTU of projected natural gas burn for generation during the period and

38% of Gulf's 26,579,547 MMBTU of actual gas burn for generation during the period.

Q. What types of hedging instruments were used by Gulf Power Company, and what type and volume of fuel was hedged by each type of instrument?

A. Natural gas was hedged primarily using financial swaps that fixed the price of gas to a certain price. The total volume of gas hedged using financial swaps was 10,030,000 MMBTU. These swaps settled against either a NYMEX Last Day price or Gas Daily price. Schedule 5 of my exhibit shows all natural gas hedge transactions incurred since the mid-year hedging report was filed with the Commission on August 14, 2009. The type of hedging instrument used for each transaction is shown on this exhibit.

Q. What was the actual total cost (e.g., fees, commissions, option premiums, futures gains and losses, swap settlements) associated with each type of hedging instrument for the period January 2009 through December 2009?

A. No fees, commissions, or premiums were paid by Gulf on the financial swap hedge transactions during this period. Schedule 5 of my exhibit also shows the associated costs that were incurred for each hedge transaction since the mid-year hedging report was filed with the Commission on August 14, 2009. Gulf's 2009 hedging program resulted in a net financial loss of $51,232,251 as shown on line 2 of Schedule A-1, period-to-date, for the month of December 2009 included in Appendix 1 of Witness Dodd's exhibit.

Q. Were there any other significant developments in Gulf's fuel procurement program during the period?

A. No.

Q. During the period January 2009 through December 2009 how did Gulf Power Company's recoverable fuel cost of power sold compare with the projection?

A. Gulf's recoverable fuel cost of power sold for the period is ($60,981,841) or 70.48% below the projected amount of ($206,568,000). Total kilowatt hours of power sales were (3,365,922,680) KWH compared to estimated sales of (4,343,477,000) KWH, or 22.51% below projections. The resulting average fuel cost of power sold was 1.8117 cents per KWH or 61.91% below the projected amount of 4.7558 cents per KWH. This information is from Schedule A-1, period-to-date, for the month of December 2009 included in Appendix 1 of Witness Dodd's exhibit.

Q. What are the reasons for the difference between Gulf's actual fuel cost of power sold and the projection?

A. The lower total credit to fuel expense from power sales is attributed to a lower amount of KWH sold and lower replacement fuel costs than originally projected. Below budget prices for natural gas reduced the fuel reimbursement rate (cents per KWH) paid to Gulf for power sales.

Q. During the period January 2009 through December 2009, how did Gulf Power Company's recoverable fuel cost of purchased power compare with the projection?

A. Gulf's recoverable fuel cost of purchased power for the period was $65,588,382 or 42.33% above the estimated amount of $46,081,000. Total kilowatt hours of purchased power were 2,654,719,648 KWH compared to the estimate of 860,543,000 KWH or 208.49% above projections. The resulting average fuel cost of purchased power was 2.4706 cents per KWH or 53.86% below the estimated amount of 5.3549 cents per KWH. This information is from Schedule A-1, period-to-date, for the month of December 2009 included in Appendix 1 of Witness Dodd's exhibit.

Q. What are the reasons for the difference between Gulf's actual fuel cost of purchased power and the projection?

A. The higher total fuel cost of purchased power is attributed to Gulf purchasing a greater amount of KWH at attractive prices to supplement its own generation to meet load demands. The average fuel cost of energy purchases per KWH was lower than projected as a result of lower-cost energy being made available to Gulf for purchase during the period. In general the actual price of marginal fuel, primarily natural gas, used to generate market energy was lower than projected for the period.

Q. Should Gulf's recoverable fuel and purchased power cost for the period be accepted as reasonable and prudent?

A. Yes. Gulf's coal supply program is based on a mixture of long-term contracts and spot purchases at market prices. Coal suppliers are selected using procedures that assure reliable coal supply, consistent quality, and competitive delivered pricing. The terms and conditions of coal supply agreements have been administered appropriately. Natural gas is purchased using agreements that tie price to published market index schedules and is transported using a combination of firm and interruptible gas transportation agreements. Natural gas storage is utilized to assure that supply is available during times when gas supply is otherwise curtailed or unavailable. Gulf's lighter oil purchases were made from qualified vendors using an open bid process to assure competitive pricing and reliable supply. Gulf adhered to its Risk Management Plan for Fuel Procurement and accomplished the objectives established by the plan. Through its participation in the integrated Southern Electric System, Gulf is able to purchase affordable energy from pool participants and other sellers of energy when needed to meet load and during times when the cost of purchased power is lower than energy that could be generated internally. Gulf is also able to sell energy to the pool when excess generation is available and return the benefits of these sales to the customer. These energy purchases and sales are governed by the IIC which is approved by the Federal Energy Regulatory Commission (FERC).

Q. During the period January 2009 through December 2009, how did Gulf's actual net purchased power capacity cost compare with the net projected cost?

A. The actual net capacity cost for the January 2009 through December 2009 recovery period, as shown on line 4 of Schedule CCA-2 of Witness Dodd's exhibit, was $31,599,634. Gulf's total projected net purchased power capacity cost for the same period was $34,921,268, as indicated on line 3 of Schedule CCE-1 of Witness Dodd's exhibit filed September 2, 2008. The difference between the actual net capacity cost and the projected net capacity cost for the recovery period is $3,321,634 or 9.51% lower than originally projected. This lower actual cost is due to Gulf's lower IIC reserve sharing costs. Gulf's actual reserves were higher than originally projected due to lower actual customer loads and less generating unit load outages on Gulf's system. Therefore, Gulf's reserve purchases were lower and its associated reserve sharing costs were lower than projected for the 2009 recovery period.

Q. Was Gulf's actual 2009 IIC capacity cost prudently incurred and properly allocated to Gulf?

A. Yes. Gulf's capacity costs were incurred in accordance with the reserve sharing provisions of the IIC in which Gulf has been a participant for many years. Gulf's participation in the integrated SES that is governed by the IIC has produced and continues to produce substantial benefits for Gulf's customers and has been recognized as being prudent by the Florida Public Service Commission in previous proceedings and reviews.
Per contractual agreement in the IIC, Gulf and the other SES operating companies are obligated to provide for the continued operation of their electric facilities in the most economical manner that achieves the highest possible service reliability. The coordinated planning of future SES generation resource additions that produce adequate reserve margins for

the benefit of all SES operating companies' customers facilitates this "continued operation" in the most economical manner. The IIC provides for mechanisms to facilitate the equitable sharing of the costs associated with the operation of facilities that exist for the mutual benefit of all the operating companies. In 2009, Gulf's reserve sharing cost represents the equitable sharing of the costs that the SES operating companies incurred to ensure that adequate generation reserve levels are available to provide reliable electric service to customers. This cost has been properly allocated to Gulf pursuant to the terms of the IIC.

Q. Mr. Ball, does this complete your testimony?
A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission

Prepared Direct Testimony of

H. R. Ball

Docket No. 100001-EI

Date of Filing: August 2, 2010

Q. Please state your name and business address.

A. My name is H. R. Ball. My business address is One Energy Place, Pensacola, Florida 32520-0335. I am the Fuel Manager for Gulf Power Company.

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

A. I graduated from the University of Southern Mississippi in Hattiesburg, Mississippi in 1978 with a Bachelor of Science Degree in Chemistry and graduated from the University of Southern Mississippi in Long Beach, Mississippi in 1988 with a Masters of Business Administration. My employment with the Southern Company began in 1978 at Mississippi Power's (MPC) Plant Daniel as a Plant Chemist. In 1982, I transferred to MPC's Fuel Department as a Fuel Business Analyst. I was promoted in 1987 to Supervisor of Chemistry and Regulatory Compliance at Plant Daniel. I was promoted to Supervisor of Coal Logistics with Southern Company Fuel Services in Birmingham, Alabama in 1998. My responsibilities included administering coal supply and transportation agreements and managing the coal inventory program for the Southern Electric System. I transferred to my current position as Fuel Manager for Gulf Power Company in 2003.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. I manage the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost. I also have responsibility for the administration of Gulf's Intercompany Interchange Contract (IIC).

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

A. The purpose of my testimony is to compare Gulf Power Company's original projected fuel and net power transaction expense and purchased power capacity costs with current estimated/actual costs for the period January 2010 through December 2010 and to summarize any noteworthy developments at Gulf in these areas. The current estimated/actual costs consist of actual expenses for the period January 2010 through June 2010 and projected fuel and net power transaction costs for July 2010 through December 2010. Projected capacity costs for July 2010 through December 2010 were reduced slightly to account for changes in capacity payments under Gulf's purchase power agreements. It is also my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel and net power transaction expenses, and purchased power capacity costs.

Q. During the period January 2010 through December 2010 how will Gulf Power Company's recoverable total fuel and net power transactions cost compare with the original cost projection?

A. Gulf's currently projected recoverable total fuel and net power transactions cost for the period is $627,549,920 which is $19,705,831 or 3.24% above the original projected amount of $607,884,089. The resulting average fuel cost is projected to be 5.0998 cents per KWH or 3.78% above the original projection of 4.9141 cents per KWH. The higher total fuel expense and average per unit fuel cost is attributed to a combination of higher than projected fuel costs for the period which are reflected in both the fuel cost of generated power and the fuel cost of purchased power and a lower amount of net energy (KWH) transactions. This current projection of fuel and net purchased power transaction cost is captured in the exhibit to Witness Dodd's testimony, Schedule E-1 B-1, Line 22.

Q. During the period January 2010 through December 2010 how will Gulf Power Company's recoverable fuel cost of generated power compare with the original projection of fuel cost?

A. Gulf's currently projected recoverable fuel cost of generated power for the period is $643,208,425 which is $4,129,337 or 0.64% below the original projected amount of $647,337,762. Total generation is expected to be 12,568,920,000 KWH compared to the original projected generation of

12,964,668,000 KWH or 3.05% below original projections. The resulting average fuel cost is expected to be 5.1175 cents per KWH or 2.49% above the original projected amount of 4.9931 cents per KWH. This current projection of fuel cost of system net generation is captured in the exhibit to Witness Dodd's testimony, Schedule E-1 B-1, Line 6.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost of generated power and the current projection?

A. The lower total fuel expense is due to lower than originally projected quantity of generated power (KWH) offset somewhat by higher average per unit fuel costs (cents/KWH). Delivered coal prices per MMBTU are projected to be above original projections for the period and natural gas prices per MMBTU are projected to be below original projections for the period due to changes in market fuel prices. The quantity of contract coal shipments for the period is expected to be below original projections due to a reduction in the quantity of coal burned. Coal burn is lower due to reduced economic dispatch of coal fired units. Market prices for natural gas and oil for the period are expected to be lower than original projections. Supply and demand imbalances in the oil and gas markets have driven the price for these fossil fuel sources lower and prices are expected to remain lower for the rest of the period. The quantity of natural gas burn is expected to be above original projections in response to the lower market prices for natural gas increasing economic dispatch of gas fired generation. The ability to change the mix of generating units operating to meet customer demand to a more heavily weighted natural gas mix has allowed Gulf to take advantage of lower natural gas prices.

Q How did the total projected fuel cost of system net generation compare to the actual cost for the first six months of 2010?

A. The total fuel cost of system net generation for the first six months of 2010 was $275,186,542 which is $24,092,239 or 8.05% lower than the projection of $299,278,781. On a fuel cost per KWH basis, the actual cost was 5.05 cents per KWH, which is 4.34% higher than the projected cost of 4.84 cents per KWH. This higher cost of system generation on a cents per KWH basis is due to a combination of fuel cost in $/MMBTU being 6.32% higher than projected and heat rate (BTU/KWH) of the generating units operating being 1.68% lower than projected. This information is found on Schedule A-3 Period to Date of the June 2010 Monthly Fuel Filing.

Q. How did the total projected cost of coal burned compare to the actual cost for the first six months of 2010?

A. The total cost of coal burned (including boiler lighter) for the first six months of 2010 was $232,171,210 which is $21,172,762 or 8.36% lower than the projection of $253,343,972. On a fuel cost per KWH basis, the actual cost was 5.28 cents per KWH which is 10.69% higher than the projected cost of 4.77 cents per KWH. The lower than projected total cost of coal burned (including boiler lighter) is due to total MMBTU of coal burn being 16.05% below the estimated burn for the period. The higher per KWH cost of coal fired generation is due to actual coal prices (including boiler lighter) being

9.07% higher than projected on a $/MMBTU basis and the weighted average heat rate (BTU/KWH) of the coal fired generating units operating being 1.42% higher than projected. This information is found on Schedule A-3 Period to Date of the June 2010 Monthly Fuel Filing. Gulf has fixed price coal contracts in place for the period to limit price volatility and ensure reliability of supply. Actual average prices for coal purchased during the period are higher due to a change in the timing of contract shipments to Gulf's coal fired generating plants. A significant amount of these contract coal shipments have been deferred to later periods in response to lower coal burn. Another factor contributing to the higher cost of coal fired generation (cents/KWH) is that weighted average coal unit heat rates are higher than projected for the period. Generating unit heat rates have been impacted by the percentage of time these units operated at lower than projected loads. When generating units operate at lower loads, unit efficiency is reduced.

Q. How did the total projected cost of natural gas burned compare to the actual cost during the first six months of 2010?

A. The total cost of natural gas burned for generation for the first six months of 2010 was $42,924,406 which is $3,010,403 or 6.55% lower than Gulf's projection of $45,934,809. The total cost of natural gas burned for generation is lower than projected due to the market price of natural gas being lower than projected. Market prices for natural gas are lower due to increased supply of natural gas in the market. On a cost per unit basis, the actual cost of gas fired generation was 4.10 cents per KWH which is

22.20% lower than the projected cost of 5.27 cents per KWH. Actual natural gas prices were $5.61 per MMBTU or 17.50% lower than the projected cost of $6.80 per MMBTU. This information is found on Schedule A-3 Period to Date of the June 2010 Monthly Fuel Filing.

Q. For the period in question, what volume of natural gas was actually hedged using a fixed price contract or instrument?

A. Gulf Power financially hedged 3,340,000 MMBTU of natural gas for the period January 2010 through June 2010 using fixed price financial swaps. This equates to 45.4% of the actual natural gas burn for the period.

Q. What types of hedging instruments were used by Gulf Power Company and what type and volume of fuel was hedged by each type of instrument?

A. Natural gas was hedged using financial swaps that fixed the price of gas to a certain price. These swaps settled against either a NYMEX Last Day price or Gas Daily price. The entire amount (3,340,000 MMBTU) of gas hedged was hedged using these financial instruments.

Q. What was the actual total cost (e.g., fees, commission, option premiums, futures gains and losses, swap settlements) associated with each type of hedging instrument?

A. No fees, commission, or option premiums were paid. Gulf's gas hedging program has resulted in a net financial loss of $9,840,293 for the period January through June 2010. This information is found on Schedule A-1, Period to Date, line 2 of the June 2010 Monthly Fuel Filing.

Q. During the period January 2010 through December 2010 how will Gulf Power Company's recoverable fuel cost of power sold compare with the original cost projection?

A. Gulf's currently projected recoverable fuel cost and gains on power sales for the period are $105,639,729 or 74.77% above the original projected amount of $60,466,000. Total megawatt hours of power sales is expected to be 3,199,437,542 KWH compared to the original projection of 1,480,362,000 KWH or 116.13% above projections. The resulting average fuel cost and gains on power sales is expected to be 3.3018 cents per KWH or 19.14% below the original projected amount of 4.0823 cents per KWH. This current projection of fuel cost of power sold is captured in the exhibit to Witness Dodd's testimony, Schedule E-1 B-1, Line 20.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost and gains on power sales and the current projection?

A. The higher total credit to fuel expense from power sales is attributed to a higher quantity of power sales made than originally projected. Lower marginal market prices for coal and natural gas during the period have decreased the fuel reimbursement rate (cents/KWH) for power sales. Lower prices for energy sales have resulted in an increased demand for this lower cost energy generated primarily from gas fired combined cycle units.

Q. How did the total projected fuel cost of power sold compare to the actual cost for the first six months of 2010?

A. The total fuel cost of power sold for the first six months of 2010 was $47,508,728 which is $12,797,728 or 36.87% higher than our projection of $34,711,000. On a fuel cost per KWH basis, the actual cost was 2.5174 cents per KWH which is 35.64% below the projected cost of 3.9112 cents per KWH. This information is found on Schedule A-1, Period to Date, line 19 of the June 2010 Monthly Fuel Filing.

Q. During the period January 2010 through December 2010 how will Gulf Power Company's recoverable fuel cost of purchased power compare with the original cost projection?

A. Gulf's currently projected recoverable fuel cost of purchased power for the period is $89,981,224 or 329.46% above the original projected amount of $20,952,327. The total amount of purchased power is expected to be 2,935,936,503 KWH compared to the original projection of 884,977,000 KWH or 231.75% above projections. The resulting average fuel cost of purchased power is expected to be 3.0648 cents per KWH or 29.45% above the original projected amount of 2.3676 cents per KWH. This current projection of fuel cost of purchased power is captured in the exhibit to Witness Dodd's testimony, Schedule E-1 B-1, Line 14.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost of purchased power and the current projection?

A. The higher total fuel cost of purchased power is attributed to a combination of Gulf purchasing a greater amount of energy to supplement its own generation to meet load demands and a higher price per KWH for purchased power than originally projected. Replacement fuel costs for purchased power are higher as a result of Gulf's need to purchase power during high peak demand periods when prices for energy are more expensive.

Q. How did the total projected fuel cost of purchased power compare to the actual cost for the first six months of 2010?

A. The total fuel cost of purchased power for the first six months of 2010 was $75,474,223 which is $58,206,707 or 337.09% higher than our projection of $17,267,516. The higher than anticipated purchased power expense is due to the actual quantity of purchases being 293.90% higher than projected. Purchase power quantity is higher due to the lower price of available power relative to Gulf's fuel cost of generated power making it the economic choice for providing energy to the customer during certain periods of time. On a fuel cost per KWH basis, the actual cost was 3.0683 cents per KWH which is 10.97% higher than the projected cost of 2.7651 cents per KWH. This information is found on Schedule A-1, Period to Date, line 12 of the June 2010 Monthly Fuel Filing.

Q. Were there any other significant developments in Gulf's fuel procurement program during the period?

A. No.

Q. Were Gulf Power's actions through June 30, 2010 to mitigate fuel and purchased power price volatility through implementation of its financial and/or physical hedging programs prudent?

A. Yes. Gulf's physical and financial fuel hedging programs have resulted in more stable fuel prices. Over the long term, Gulf anticipates less volatile future fuel costs than would have otherwise occurred if these programs had not been utilized.

Q. Should Gulf's fuel and net power transactions cost for the period be accepted as reasonable and prudent?

A. Yes. Gulf has followed its Risk Management Plan for Fuel Procurement in securing the fuel supply for its electric generating plants. Gulf's coal supply program is based on a mixture of long-term contracts and spot purchases at market prices. Coal suppliers are selected using procedures that assure reliable coal supply, consistent quality, and competitive delivered pricing. The terms and conditions of coal supply agreements have been administered appropriately. Natural gas is purchased using agreements that tie price to published market index schedules and is transported using a combination of firm and interruptible gas transportation agreements. Natural gas storage is utilized to assure that natural gas is available during times when gas supply is curtailed or unavailable. Gulf's fuel oil purchases were made from qualified vendors using an open bid process to assure competitive pricing and reliable supply. Gulf makes sales of power when available and gets reimbursed at the marginal cost of replacement fuel. This fuel reimbursement is credited back to the fuel cost recovery clause so that lower cost fuel purchases made on behalf of Gulf's customers remain to the benefit of those customers. Gulf purchases power when necessary to meet customer load requirements and when the cost of purchased power is expected to be less than the cost of system generation. The fuel cost of purchased power is the lowest cost available in the market at the time of purchase to meet Gulf's load requirements.

Q. During the period January 2010 through December 2010, what is Gulf's projection of actual / estimated net purchased power capacity transactions and how does it compare with the company's original projection of net capacity transactions?

A. As shown on Line 4 of Schedule CCE-1b in the exhibit to Witness Dodd's testimony, Gulf's total current net capacity payment projection for the January 2010 through December 2010 recovery period is $47,966,055. Gulf's original projection for the period was $48,729,557 and is shown on Line 4 of Schedule CCE-1 filed October 30, 2009. The difference between these projections is $763,502 or 1.57% less than the original projection of net capacity payments. Actual capacity payments during the first six months of 2010 were $1,633,065 or 10.45% lower than projected for the period due to timing differences between actual payments and projected payments for the period.

Q. Mr. Ball, does this complete your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
H. R. Ball
Docket No. 100001-EI
Date of Filing: September 1, 2010

Q. Please state your name and business address.

A. My name is H. R. Ball. My business address is One Energy Place, Pensacola, Florida 32520-0335. I am the Fuel Manager for Gulf Power Company.

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

A. I graduated from the University of Southern Mississippi in Hattiesburg, Mississippi in 1978 with a Bachelor of Science Degree in Chemistry and graduated from the University of Southern Mississippi in Long Beach, Mississippi in 1988 with a Masters of Business Administration. My employment with the Southern Company began in 1978 at Mississippi Power's (MPC) Plant Daniel as a Plant Chemist. In 1982, I transferred to MPC's Fuel Department as a Fuel Business Analyst. I was promoted in 1987 to Supervisor of Chemistry and Regulatory Compliance at Plant Daniel. In 1988, I assumed the role of Supervisor of Coal Logistics with Southern Company Fuel Services in Birmingham, Alabama. My responsibilities included administering coal supply and transportation agreements and managing the coal inventory program for the Southern electric system. I transferred to my current position as Fuel Manager for Gulf Power Company in 2003.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. My responsibilities include the management of the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost. I also have responsibility for the administration of Gulf's Intercompany Interchange Contract (IIC).

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

A. The purpose of my testimony is to support Gulf Power Company's projection of fuel expenses, net power transaction expense, and purchased power capacity costs for the period January 1, 2011 through December 31, 2011. It is also my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel and net power transaction expenses and purchased power capacity costs.

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

A. Yes, I have three separate exhibits I am sponsoring as part of this testimony. My first exhibit (HRB–2) consists of a schedule filed as an attachment to my pre-filed testimony that compares actual and projected fuel cost of net generation for the past ten years. The purpose of this exhibit is to indicate the accuracy of Gulf's short-term fuel expense projections. The second exhibit (HRB-3) I am sponsoring as part of this testimony is Gulf Power Company's Hedging Information Report filed with the Commission Clerk on August 16, 2010 and assigned Document Number DN 06783-10 (redacted) and 06782-10 (confidential information). The purpose of this second exhibit is to comply with Order No. PSC-08-0316-PAA-EI and details Gulf Power's natural gas hedging transactions for January through July 2010. The third exhibit (HRB-4) I am sponsoring is Gulf Power Company's "Risk Management Plan for Fuel Procurement" filed with the Commission Clerk pursuant to a separate request for confidential classification on August 2, 2010 and assigned Document Number DN 06262-10 (redacted) and 06265-10 (confidential information). The risk management plan sets forth Gulf Power's fuel procurement strategy and related hedging plan for the upcoming calendar year. Through its petition in this docket, Gulf Power is seeking the Commission's approval of the Company's "Risk Management Plan for Fuel Procurement" as part of this proceeding.

Counsel: We ask that Mr. Ball's three exhibits as just described be marked for identification as Exhibit Nos. _____ (HRB-2), ______ (HRB-3), and______ (HRB-4) respectively.

Q. Has Gulf Power Company made any significant changes to its methods for projecting fuel expenses, net power transaction expense, and purchased power capacity costs for this period?

A. No. Gulf has been consistent in how it projects annual fuel expenses, net power transactions, and capacity costs.

Q. What is Gulf's projected recoverable total fuel and net power transactions cost for the January 2011 through December 2011 recovery period?

A. Gulf's projected total fuel and net power transaction cost for the period is $574,403,797. This projected amount is captured in the exhibit to Witness Dodd's testimony, Schedule E-1, line 19.

Q. How does the total projected fuel and net power transactions cost for the 2011 period compare to the updated projection of fuel cost for the same period in 2010?

A. The total updated cost of fuel and net power transactions for 2010, reflected on Schedule E-1B-1 line 22 of Witness Dodd's testimony filed in this docket on August 2, 2010, is projected to be $627,549,920. The projected total cost of fuel and net power transactions for the 2011 period reflects a decrease of $53,146,123 or 8.47% over the same period in 2010. On a fuel cost per KWH basis, the 2010 projected cost is 5.0998 cents per KWH and the 2011 projected fuel cost is 4.6847 cents per KWH, a decrease of 0.4151 cents per KWH or 8.14%.

Q. What is Gulf's projected recoverable fuel cost of net generation for the period?

A. The projected total cost of fuel to meet system net generation needs in 2011 is $621,972,069. The projection of fuel cost of system net generation for 2011 is captured in the exhibit to Witness Dodd's testimony, Schedule E-1, line 1.

Q. How does the total projected fuel cost of net generation for the 2011 period compare to the updated projection of fuel cost for the same period in 2010?

A. The total updated cost of fuel to meet 2010 system net generation needs, reflected on Schedule E-1B-1, line 1 of Witness Dodd's testimony filed in this docket on August 2, 2010, is projected to be $623,052,860. The projected total cost of fuel to meet system net generation needs for the 2011 period reflects a decrease of $1,080,791or 0.17% over the same period in 2010. Total system net generation in 2011 is projected to be 13,244,806,000 KWH, which is 729,207,000 KWH or 5.83% higher than is currently projected for 2010. On a fuel cost per KWH basis, the 2010 projected cost is 4.9782 cents per KWH and the 2011 projected fuel cost is 4.6960 cents per KWH, a decrease of 0.2822 cents per KWH or 5.67%. This lower projected total fuel expense and average per unit fuel cost is the result of a lower cost of coal for the period. Weighted average coal price including boiler lighter fuel for 2010 as reflected on Schedule E-3, line 32 of Witness Dodd's testimony filed in this docket on August 2, 2010, is projected to be 4.91 $/MMBTU. Weighted average coal price including boiler lighter fuel for 2011, as reflected on Schedule E-3, line 32 of the exhibit to Witness Dodd's testimony, is projected to be 4.58 $/MMBTU. This reflects a cost decrease of 0.33 $/MMBTU or 6.72%. Several of Gulf's coal supply agreements will expire at the end of 2010 and these are being replaced with lower priced coal supply agreements that have two year terms expiring at the end of 2012. Gulf's coal supply agreements have firm price and quantity commitments with the contract coal suppliers and these agreements will cover the majority of Gulf's 2011 projected coal burn needs. Weighted average natural gas price for 2010, as reflected on Schedule E-3, line 33 of the exhibit to Witness Dodd's testimony filed in this docket on August 2, 2010, is projected to be 5.08 $/MMBTU. Weighted average natural gas price for 2011, as reflected on Schedule E-3, line 33 of the exhibit to Witness Dodd's testimony, is projected to be 6.02 $/MMBTU. This is an increase in price of 0.94 $/MMBTU or 18.50% and reflects forecasted higher market prices for natural gas in 2011. The projected cost of landfill gas to supply the Perdido Landfill Gas to Energy Facility reflects a full year of plant operation for the first time in the 2011 projection period. The generating plant is scheduled to begin operation in September 2010. The total projected cost for landfill gas in 2011 is $638,895 and the total facility generation is projected to be 25,363,000 KWH. The average rate, as reflected on Schedule E-3, line 42 of the exhibit to Witness Dodd's testimony, is projected to be 2.52 cents per KWH.

Q. Does the 2011 projection of fuel cost of net generation reflect any major changes in Gulf's fuel procurement program for this period?

A. No. As in the past, Gulf's coal requirements are purchased in the market through the Request for Proposal (RFP) process that has been used for many years by Southern Company Services - Fuel Services as agent for Gulf. Coal will be delivered under both existing and new negotiated coal transportation contracts. Natural gas requirements will be purchased from various suppliers using firm quantity agreements with market pricing for base needs and on the daily spot market when necessary. Natural gas transportation will be secured using a combination of firm and spot transportation agreements. Details of Gulf's fuel procurement strategy are included in the "Risk Management Plan for Fuel Procurement" filed as exhibit _____ (HRB-4) to this testimony.

Q. What actions does Gulf take to procure natural gas and natural gas transportation for its units at competitive prices for both long-term and short-term deliveries?

A. Gulf procures natural gas using both long and short-term agreements for gas supply at market-based prices. Gulf secures gas transportation for non-peaking units using long-term agreements for firm transportation capacity and for peaking units using interruptible transportation, released seasonal firm transportation, or delivered natural gas agreements.

Q. What fuel price hedging programs will be utilized by Gulf to protect the customer from fuel price volatility?

A. As detailed in Gulf's "Risk Management Plan for Fuel Procurement", natural gas prices will be hedged financially using instruments that conform to Gulf's established guidelines for hedging activity. Coal supply and transportation prices will be hedged physically using term agreements with either fixed pricing or term pricing with escalation terms tied to various published market price indexes. Gulf's "Risk Management Plan for Fuel Procurement" is a reasonable and appropriate strategy for protecting the customer from fuel price volatility while maintaining a reliable supply of fuel for the operation of its electric generating resources.

Q. What are the results of Gulf's fuel price hedging program for the period January 2010 through July 2010?

A. Gulf's coal price hedging program has successfully managed the price it pays for coal under its coal supply agreements for this period. Gulf has also had financial hedges in place during the period to hedge the price of natural gas. These financial hedges have been effective in fixing the price of a percentage of Gulf's gas burn during the period. Pursuant to Order No. PSC-08-0316-PAA-EI, Gulf filed a "Hedging Information Report" with the Commission on August 16, 2010 detailing its natural gas hedging transactions for January 2010 through July 2010. As noted earlier, I am sponsoring this report as exhibit ______ (HRB-3) to my testimony in this docket.

Q. Has Gulf adequately mitigated the price risk of natural gas and purchased power for 2010 through 2011?

A. Gulf has adequate natural gas financial hedges in place for 2010 to mitigate price risk. Gulf currently has natural gas hedges in place for 2011 and continues to look for opportunities to enter into financial hedges that we believe will provide price stability to the customer and protect against unanticipated dramatic price increases in the natural gas market.

Q. Should recent changes in the market price for natural gas impact the percentage of Gulf's natural gas requirements that Gulf plans to hedge?

A. Gulf has a disciplined process in place to evaluate the benefits of gas hedging transactions prior to entering into financial hedges that consider both market price and anticipated burn. The focus of this process is to mitigate the price volatility and risk of natural gas purchases for the customer and not to attempt to speculate in the natural gas market. Gulf's current strategy is to have gas hedges in place that do not exceed the anticipated gas burn at its Smith Unit 3 combined cycle plant. Gas burn requirements change as the market price of natural gas changes due to the economic dispatch process utilized by the Southern System generation pool in accordance with the IIC. Typically, as gas prices increase, anticipated gas burn decreases and the percentage of gas requirements that are currently hedged financially increases. Gulf will continue to evaluate the performance of this hedging strategy and will make adjustments within the guidelines of the currently approved hedging program when needed.

Q. What is Gulf's projected recoverable fuel cost of power sold for the period?

A. Gulf's projected recoverable fuel cost of power sold is $84,732,000. This projected amount is captured in the exhibit to Witness Dodd's testimony, Schedule E-1, line 17.

Q. How does the total projected recoverable fuel cost of power sold for the 2011 period compare to the projected recoverable fuel cost of power sold for the same period in 2010?

A. The total projected recoverable fuel cost of power sold in 2010, reflected on Schedule E-1B-1, line 20 of Witness Dodd's testimony filed in this docket on August 2, 2010, is projected to be $105,639,729. The projected recoverable fuel cost of power sold in 2011 represents a decreased credit of $20,907,729 or 19.79%. Total quantity of power sales in 2011 is projected to be 1,963,232,000 KWH, which is 1,236,205,542 KWH or 38.64% less than currently projected for 2010. On a fuel cost per KWH basis, the 2010 projected cost is 3.3018 cents per KWH and the 2011 projected fuel cost is 4.3159 cents per KWH, which is an increase of 1.0141 cents per KWH or 30.71%. This higher total credit to fuel expense from power sales is attributed to a higher fuel reimbursement rate (cents per KWH) for power sales as a result of higher projected market prices for natural gas. Higher fuel costs to operate Gulf's generating fleet are passed on to the purchasers of power and are reflected in the higher fuel cost and gains on power sales.

Q. What is Gulf's projected total cost of purchased power for the period?

A. Gulf's projected recoverable cost for energy purchases is $34,635,000. This projected amount is captured in the exhibit to Witness Dodd's testimony, Schedule E-1, line 12.

Q. How does the total projected purchased power cost for the 2011 period compare to the projected purchased power cost for the same period in 2010?

A. The total updated cost of purchased power to meet 2010 system needs, reflected on Schedule E-1B-1, line 14 of Witness Dodd's testimony filed in this docket on August 2, 2010, is projected to be $89,981,224. The projected cost of purchased power to meet system needs in 2011 is $55,346,224 or 61.51% less than is currently projected for 2010. The total quantity of purchased power in 2011 is projected to be 929,227,000 KWH, which is 2,006,709,503 KWH or 68.35% lower than is currently projected for 2010. On a fuel cost per KWH basis, the 2010 projected cost is 3.0648 cents per KWH and the 2011 projected fuel cost is 3.7273 cents per KWH, which represents an increase of 0.6625 cents per KWH or 21.62%.

Q. What is Gulf's projected recoverable capacity payments for the period?

A. The total recoverable capacity payments for the period are $45,129,549. This amount is captured in the exhibit to Witness Dodd's testimony, Schedule CCE-1, line 10. Schedule CCE-4 of Mr. Dodd's testimony lists the long-term power contracts that are included for capacity cost recovery, their associated capacity amounts in megawatts, and the resulting capacity dollar amounts. Also included in Gulf's 2011 projection of capacity cost is revenue produced by a market-based service agreement between the Southern electric system operating companies and South Carolina PSA. This total revenue of $41,568 is shown on page 2 of Schedule CCE-4, line 33 in the exhibit to Witness Dodd's testimony. The total capacity cost included on Schedule CCE-4 is presented on lines 1 and 2 of Schedule CCE-1.

Q. Have there been any new purchased power agreements entered into by Gulf that impact the total recoverable capacity payments?

A. No.

Q. What are the other projected revenues that Gulf has included in its capacity cost recovery clause for the period?

A. Gulf has included an estimate of transmission revenues in the amount of $253,000 in its capacity cost recovery projection. This amount is captured in the exhibit to Witness Dodd's testimony, Schedule CCE-1, line 3.

Q. How does the total projected net capacity cost for the 2011 period compare to the current estimated net capacity cost for the same period in 2010?

A. Gulf's 2011 Projected Jurisdictional Capacity Payments, found in the exhibit to Witness Dodd's testimony, Schedule CCE-1, line 6, is projected to be $48,260,759. This amount is $2,011,121 or 4.35% greater than the current estimate of $46,249,638 (Schedule CCE-1B, line 6) for 2010 that was filed in Mr. Dodd's estimated/actual true-up testimony in this docket on August 2, 2010. This increase is primarily the result of the increase in monthly capacity rates as specified in Gulf's purchase power agreement with Shell Energy North America, L.P.

Q. Mr. Ball, does this complete your testimony?

A. Yes, it does.

MR. BADDERS: At this time we'll tender this witness for cross. He's waiving his right for a summary.

CHAIRMAN GRAHAM: Okay. Thank you.

Mr. Moyle, I think you're up first.

CROSS EXAMINATION

MR. MOYLE: Thank you, Mr. Chairman.

BY MR. MOYLE:

Q Mr. Ball, good afternoon.

A Good afternoon.

Q Jon Moyle. I represent a group of large industrial users of electricity. And you were here earlier in the morning, were you not?

A Yes, I was.

Q Okay. And FIPUG has raised an issue related to hedging, so I want to spend most of my time asking you some questions about hedging. That's an area that you have responsibility for; correct?

A Correct.

Q Okay. And in terms of your responsibility for it, are you the one that runs the hedging program for, for Gulf?

A I don't actually enter into the hedge positions. I oversee or direct the activities of the individuals that do for Gulf.

Q Okay. And so who is your, your kind of report up the ladder, if you will, with respect to the hedging program?

A Well, with respect to the hedging program, I report to the Chief Financial Officer of Gulf Power Company.

Q Okay. And does Gulf Power have in effect control of its hedging operations or is there a Risk Management Committee within the Southern Group that has the ultimate control or is it some variation?

A Gulf Power controls its hedging program.

Q Okay. Now can you describe for me the generation mix of Gulf Power in terms of its assets and what fuels those, those assets use?

A Gulf Power Company is primarily a coal-fired utility. So the vast majority of our assets are in coal-fired generating plants. We do also have a, one combined cycle gas-fired plant in Panama City. We have several purchased power agreements which are all also gas-fired for the most part. And then we have a small landfill gas facility that just went into operation about a month ago.

Q Okay. So if we were to put percentages, I mean, not -- just give a ball park with respect to coal. Is it 70, 80, 60 percent in terms of your generation mix?

A As far as the generation mix, typically coal makes up 75 to 80 percent.

Q And you all don't hedge coal, do you?

A Not financially, no.

Q And why, why is that?

A It's just not a commodity that's easily hedged financially because there's not a liquid commodity market for coal. Due to the various characteristics of coal that are used at different generating plants, it's just not a homogeneous product similar to natural gas or oil.

Q Are there, are there no financial hedge projects -- excuse me -- no financial hedge products available in any way, shape or form for coal?

A Not at, not at Gulf Power Company. No.

Q So you only have one, one natural gas plant. It's a combined cycle plant; correct?

A That's correct.

Q Okay.

A Now I, just to clarify, we have one natural gas-fired combined cycle plant that's owned and operated by Gulf Power Company.

Q Yes, sir. I had some questions of the earlier witness about, about, about hedging. In effect, if you had a different fuel mix, that maybe that would reduce the need to hedge. And I'd ask that same question of you. I mean, given the fact that coal is 80 percent, natural gas is, what, 10 percent maybe of your fuel mix?

A In the order of 20 percent.

Q 20 percent. Okay. And you include that landfill gas as part of the natural gas?

A Yes. The landfill gas is very, very small.

Q Okay. But, but given that, doesn't that provide some protection against, against price spikes for consumers, the fact that you have 80 percent coal, 20 percent natural gas, as compared to maybe a utility like Tallahassee? Are you familiar with Tallahassee and what their, what their generation mix is?

A No, I'm not.

Q Okay. Well, I'd represent to you that just for the purposes of the question it's mainly natural gas-fired units. But given the fact that you're 80 percent coal, doesn't that provide some mitigation against increases in natural gas?

A To the point that coal-fired generation is less expensive than natural gas-fired generation at certain times, there is the ability to shift generation more heavily towards the coal side of our fleet. And the outfit (phonetic) could potentially take place where coal prices were more expensive than gas on a cents-per-kilowatt-hour basis. You could shift more generation towards your gas-fired assets.

To the point that you, I mean, there's some physical limitations in that as well such as loads at a certain time and how much each one of those assets are being used. But, yeah, I think generally you could, you could say that you could move generation around between coal and gas depending on relative price to each other.

Q And with respect to what is it, what is it that Gulf Power hedges against with respect to its hedging of natural gas? What's the object of the hedge, if you will?

A It's to limit the price volatility of natural gas pricing.

Q And are you doing that?

A Yes.

Q And how do you know you're doing that?

A We actually measure the volatility of the price hedged and unhedged, and we've made some standard deviation calculations and come to the conclusion that, yes, indeed, a fixed price is less volatile than a floating price.

Q And that's true just because of the fact that you're hedged, right, rather than buying, you know, I'm all in on the spot market and say, well, I'm 50 percent in on the spot market and the other portion is hedged. Just the very fact that you're hedged means you won't have as much volatility; correct?

A That's right. If your financial hedge is essentially locking into a fixed price, obviously a fixed price is going to be not volatile.

Q How, how did the hedging program work in 2009 in terms of win/loss for the, for the customers, for the consumers?

A Well, if we're talking about volatility of pricing, I would argue that, or I would state that, yes, prices were less volatile as a result of our hedging program in 2009.

In regards to the accumulated losses against associated positions, I think it was around $51 million of loss in 2009.

Q Okay. The same question with respect to 2010.

A Well, 2010 is not complete yet. But I think through -- the latest number I saw, I think what we filed was around 9.8 million that, our loss position through July I, believe it was.

Q Okay. I think that was through August. Have you updated that number?

A Have we updated the number?

Q Yes, sir.

A I do have some updated information, yes.

Q Could you provide that to the Commission with respect to your 2010 hedging loss or gain?

A Let's see. It looks like we're right around 15 million through the end of September losses.

Q All right. And then with respect to 2011, are you, you know, with respect to a mark to market position, do you have information as to how you are positioned relative to 2011 as we sit here today based on hedges that you already have in place?

A Based on the hedges that we already have in place, and the last I looked was as of the 29th market pricing, the, our mark to market was around $11.5 million of loss or projected loss.

MR. MOYLE: Mr. Chairman, I have an exhibit I'd like to use with this witness, if I could approach and pass it out.

CHAIRMAN GRAHAM: Yes, sir. I think Staff will help you pass that out.

For identification purposes we'll mark this as Exhibit 68.

(Exhibit 68 marked for identification.)

Do you have a short title for this?

MR. MOYLE: The title is Composite of Exhibit of Excerpted Gulf Hedging Information. I think it's already been entered on the cover sheet there.

CHAIRMAN GRAHAM: We're going to have to send you to the same school as Mr. Bennett on short titles.

MR. MOYLE: I'm going to interpose the same lawyer defense.

BYMR. MOYLE:

Q Sir, I've handed you what's been marked as Exhibit 68. Could you identify the three documents attached to the exhibit, please?

A The first two pages are schedules out of my true-up testimony, and the third page is out of Gulf's risk management plan for fuel procurement, which, which we, I believe we have filed it for 2011. It looks, it appears that it's the 2011 plan.

Q Yes, sir, it is. And for your counsel, there was some confidential information that was found below on that pricing strategy, and I just blanked that out so that we could talk publicly about this exhibit, so.

MR. BADDERS: I can confirm that. There's no confidential information on either of these pages.

MR. MOYLE: Thank you.

BY MR. MOYLE:

Q All right. So the first Schedule 4, what is the purpose of this document?

A The purpose of this document was to demonstrate the, the volatility of pricing relative to market price relative to hedge price for the period January '06 through December '09.

Q All right. And if you look at the second column, gas cost for generation actual cost, and then you look at the fourth line, gas cost for generation hedge cost.

A Yes.

Q Am I reading that so that the, that the one with the hedge cost is what you, what you actually paid for it per the hedge, and the second line is what the cost was with respect to the market; is that right?

A The gas cost for generation hedged cost is essentially the sum of the market price of gas that we paid for that particular month with a hedge settlement amount added to it.

Q All right. And so the last two lines, the gas cost of generation actual cost and the gas cost of generation hedged cost, what do those two columns indicate?

A That's essentially the total cost divided by the MMBtus burned for that particular month.

Q So in January 2006, what, what was the, what was the cost of your, of your hedge generation? It was 11.53 per million Btu; is that right?

A That's correct.

Q Okay. And on the, on the second page, I carried over the columns with the, with the handwritten notes. Those are mine. But there are a couple of numbers at the top with brackets around them. What do those represent?

A Those represent gains.

Q Those represent financial gains; is that right?

A Financial gains in those months. That's correct.

Q Okay. So those months would be good months for the consumer in that they would have a financial gain; correct?

A Well, that's not the purpose of the program, to generate gains or losses. Our purpose of the program and the purpose of this schedule is to demonstrate that, yes, indeed, hedging does reduce volatility.

Q Okay. But at the end of the day, and I, I understand the reducing volatility, but with respect to what you're here asking this Commission for today, it's to set a fuel factor that would take into account losses in the hedging program; correct?

A That's correct.

Q Okay. So when I use the comment about, well, that was a situation in which the consumers benefited financially, that's what I'm referring to. Because ultimately that is a measurement with respect to the consumers and how much it impacts their bills; correct?

A In the case of the hedged settlement amount it definitely does impact the consumer's bill. I agree with that. It doesn't reflect necessarily the cost of fuel to the consumer during that month.

Q So this chart, I counted 48 months that are reflected on this chart starting January 2006 running down to December 2009. And out of, out of those 48 months, you would agree that there were five months in which the settlement total cost benefited the consumer financially; correct?

A There was a gain in those five months. That's correct.

Q So we've heard some testimony earlier and there's some information in the hedging report about, well, if the gas prices are, are coming down, maybe there will be some, some losses because you were hedged at a higher amount. Isn't that generally right?

A Yes. If you enter into a hedge position at a higher cost than eventually what the market determines the price of gas is going to be, yes, you will incur a loss.

Q And, conversely, if the prices are going up and you're, you're hedged, then you should see a gain; correct?

A That's correct.

Q Okay. So the last chart here is, is -- describe that, if you would, the chart that's on the third page of the exhibit.

A Okay.

Q Just tell us what that is.

A That's just a historical natural gas price by month. So this is actual market prices for gas by month.

Q Okay. And it includes the time frame, this chart includes the time frame that's represented on the first two pages of your exhibit; correct?

A Yes, it does.

Q Okay. Now looking at the chart, you know, it appears that there are periods where the gas price is, is going up that's not necessarily reflected with additional savings, financial savings for, for the consumers; correct?

A Well, the -- I'm not sure that you can draw a relationship between the fact that the price is going up and hedging gains or losses. It just depends on at what point in time you actually entered into a hedge transaction and what that reflected as far as a settlement, what the price in the market was at the time of the settlement of the, of the hedge position.

Q As part of your hedging program do you all try to figure out which way the market is going and time your, your hedges depending on, on which way you think the market is going to move?

A No. We don't try to guess where the market is going. Essentially what we do in the majority of cases is we know if the market is trending downward or trending upward. And our general policy is that when we enter into hedges, we're entering into the hedges as the market is declining in price.

Q The, the people that hedge financially that are up on, up on the commodities markets, they in effect are taking a bet on which way the market is going often times; correct?

A No. I would not agree with that statement.

Q I'm not saying you, but I'm saying the, you know, the gas brokers and things like that, they're not --

A No. People that are speculating on the marketplace? Yeah. Speculators do make a bet. But that's not the purpose of this program; it's not to speculate.

Q Right. Right. I guess, I guess the concern that some of the consumers have is if I looked at the 48 months and you're in the money five months, I mean, that's not a great percentage in terms of being in the money; correct? What is it, 12 percent, give or take?

A Well, I just reiterate our position on hedges and losses is that we are -- this hedge program is not designed to generate gains and it's certainly not designed to generate losses.

Essentially all we're trying to do is limit the volatility of the natural gas price, and that's the purpose of this program.

There are going to be times when there are gains, there are going to be times when there are losses. I think if you'll look at the entire period, not just from 2006, but if you'll look at the inception of the program where we've been hedging since 2002, I think the first four years indicated for those, the cumulative amount for those years, we were all -- there were a lot of gains in those first four years and then there started to be losses. And it's directly related to when you enter into a hedge position relative to where the market is going in the future. If there are big market declines, you can expect to have hedge losses.

Q Yeah. And I, I would have expected, given this chart that you have here, if you look between 2006 and 2007, you see that there is a spot where it was down to $4, and then it jumped up to, it looks like, you know, $9 give or take. Do you see that?

A I see that.

Q And I would have expected that, given that increase in, in price, that you would have had a corresponding entry in your Schedule 4 that would have reflected that the hedge positions worked out for consumers. But that, that's not the case; correct?

A Well, certainly if we were, had a crystal ball and we knew that at some point in time there was going to be a, you could hedge all your gas at $4 and you had the foresight of knowing what the future was and you -- we would have certainly hedged it all as much as we could at $4. But we don't have the benefit of that foreknowledge of where the market is going.

So the conclusion that just because there is a $4 price on here that you can expect to have the gains for the future period, that just doesn't hold true in the case of our hedging program because we don't hedge all of our gas at one point in time. It's a process over -- I mean, we're essentially hedging gas every month. There's a strategy that comes out monthly, and if it looks appropriate to enter into hedges, we'll do that. We're just not doing it all at one time.

Q Okay. You're familiar with the PSC's order that there is Mr. -- Commissioner Skop had asked some questions about it earlier. There was a recent order

PSC-080667. Are you familiar with that order?

A To some degree, yes.

Q Okay. And you try to build your hedging plan consistent with that order; correct?

A That's correct.

Q Okay. There's a statement in that order, I'll just read it to you. It says, "Each utility must continue to gauge its customers' tolerance of the cost associated with hedging versus the benefits of reduced fuel cost volatility and any resulting rate increases." Do you agree with that statement?

A I -- if it's in the order, yes, I agree with it.

(Laughter.)

CHAIRMAN GRAHAM: Smart man.

BY MR. MOYLE:

Q Yeah. It talked about the PSC audit results regarding hedging. But if you did not have a hedging program and if you weren't here today asking the, the Commission to approve 50 million in losses for 2009, do you know how much that would translate into on a, on a customer's bill, a thousand megawatt typical customer, residential customer that you have?

A No, I don't.

Q Okay. The same order, are you aware that it was reported that the OPC's comments were that, and I'm quoting, with respect to reducing fuel price volatility felt by retail customers, which is the single purpose of hedging identified by the utilities, the hedging activities are of limited value to customers, while the cost of those activities have never been quantified satisfactorily? And that, that's a quote from OPC. So I'll ask you the same question with respect to whether you agree with that, with that preface. But do you agree that, that, that the hedging activities are of limited value to customers?

A No, I don't agree with that.

Q And that's because of the fact that it, in your opinion, reduces volatility, fuel price volatility?

A Well, due to the fact that the Commission has, has, has issued an order that said it is to the benefit of the customers.

Q Okay.

A So, again, I'm going -- I'll agree with the Commission on this one.

Q I got you. Now, but just beyond the order, if -- do you have any other basis to say that other than the fact that that's what the Commission said in its order?

A Well, the, the hedging program complies with the order and it is accomplishing the goal or the objective that the Commission set forth in the order, and that's to limit price volatility of natural gas.

Q You all didn't participate in hedging activities prior to the 1992 order; correct?

A We didn't, we didn't have any natural gas-fired generation until, I think, 2002 or 2003.

MR. MOYLE: Okay. One, one second, please.

CHAIRMAN GRAHAM: Take your time.

MR. MOYLE: Those are all the questions I have. Thank you.

CHAIRMAN GRAHAM: Thank you, sir.

Mr. Beck, any? Staff?

MS. BENNETT: I have a couple.

CROSS EXAMINATION

BY MS. BENNETT:

Q Mr. Ball, you were in the room earlier when Mr. McCallister from Progress was testifying; is that correct?

A That's correct.

Q And we discussed with Mr. McCallister the 2008 staff management hedging report. Were you there for that discussion?

A Yes, I was.

Q Were you in the position of having responsibility for hedging for Gulf during the 2008 period time frame?

A Yes.

Q And were you involved with the Staff's data request and the auditors when they sought information from Gulf on the hedging results?

A Yes, I was.

Q Can you tell the Commission the process that Gulf was involved in in providing the information to the Staff for the hedging report?

A Well, just generally I can say that we provided quite a bit of data. We sat down and had interviews regarding the hedging program not only with myself, other staff members, the individuals that actually performed the hedging, entered into the transaction. So there was quite a bit of interaction between the staff that prepared this audit and ourselves.

Q And did that culminate in the issuance of Order Number PSC-080667-PAA?

A Yes.

MS. BENNETT: I have no further questions of this witness.

CHAIRMAN GRAHAM: Thank you. To the Commission board.

Commissioner Skop.

COMMISSIONER SKOP: Thank you.

Good afternoon, Mr. Ball.

THE WITNESS: Good afternoon.

COMMISSIONER SKOP: Just a quick question. On page 8 of your direct testimony dated March 12th, 2010, beginning at line nine, you indicated that Gulf uses physical hedges to reduce its price volatility in the coal procurement program; is that correct?

THE WITNESS: That's correct.

COMMISSIONER SKOP: And the majority of Gulf Power's generation is coal-fired generation; is that correct?

THE WITNESS: Yes, the majority is.

COMMISSIONER SKOP: Okay. And then in relation to what's been marked for identification as Exhibit 68, on the last page of that exhibit, which is identified as Page 39 of 102 where it shows the historical NYMEX natural gas prices, could I ask you to take a look at that chart real quick.

THE WITNESS: Okay.

COMMISSIONER SKOP: Okay. And on the curve shown for price and dollars per MMBtu, starting at mid 2005 to the beginning of 2006, do you see that sharp escalation in natural gas prices?

THE WITNESS: Yes.

COMMISSIONER SKOP: Okay. And then also on that same graph beginning at the midpoint of 2007 continuing on to what appears to be the midpoint of 2008, do you see also that sharp increase in natural gas prices?

THE WITNESS: Yes, I see that.

COMMISSIONER SKOP: Okay. What would be the -- are you familiar with the Commission's rule for midcourse fuel corrections?

THE WITNESS: Yes, I am.

COMMISSIONER SKOP: Okay. And that requires if there's a 10 percent under recovery, that the investor-owned utility would have to come into the Commission and request either recovery of those amounts or show, you know, if it's under recovery, overrecovery.

What would happen in those instances if natural gas prices had not been hedged? Would that result, in your opinion, of the utility would have had to come in for those midcourse corrections?

THE WITNESS: Well, in the case of Gulf, since natural gas is a relatively small percentage of our total fuel cost, I'm not really certain that our hedge position would have prevented us from having to come in for a midcourse correction in these periods.

Now obviously the more natural gas you have as a fuel source for your generating plants, then, yes, that would be a true statement that it could potentially prevent you from coming in for a midcourse correction.

COMMISSIONER SKOP: Okay. So in Gulf's specific case, because the percentage of gas-fired generation is small in comparison to its total generation portfolio or generation mix, even if natural gas prices were to increase precipitously upward by over 100 percent what they were at any given point in time, that probably would not trigger because the, trigger the midcourse correction because it's based on the entire fuel portfolio; is that correct?

THE WITNESS: That's correct. I mean, other than, you know, I haven't really studied this in great detail, so I wouldn't say that it's not possible that a very large increase in natural gas prices, if we were not hedged, could, could potentially result in having to make a midcourse correction.

COMMISSIONER SKOP: Okay. And any time that you enter into a, a hedge, whether it be a financial hedge or a physical transaction or subsequently unwind that hedge, there is a transaction cost associated with doing so; is that correct?

THE WITNESS: Only to the, only to the point that there is a gain or a loss. I mean, we don't actually pay any, any fees associated with those transactions.

COMMISSIONER SKOP: Okay. All right. And finally, on that same exhibit, which is, I think, the third page in, which is identified as Schedule 4, page 2 of 2, where it actually shows -- I think that you mentioned that the settlement total being the numbers in parentheses are actually savings to Gulf ratepayers as a result of the hedge transaction in those months; is that correct?

THE WITNESS: That's correct. Those are gains. Yes.

COMMISSIONER SKOP: Okay. And correlating those to the natural gas curve, those gains occurred in months in which the price of natural gas on the forward curves were rising significantly; is that correct?

THE WITNESS: That's correct.

COMMISSIONER SKOP: Okay. And with respect to placing hedges, would you agree that the timing of those hedges is important as to ascertaining at any given time whether that hedge will result in a savings or a cost to ratepayers?

THE WITNESS: Yes. The, the time when you actually enter into a transaction or enter into a hedge position, that does determine at the time that you settle it relative to the market price whether there will be a gain or a loss.

COMMISSIONER SKOP: Okay. So based on hedging practices, and I think that if I heard you correctly, the hedging is done by Southern Company, not Gulf specifically; is that correct?

THE WITNESS: These, this program is -- the hedge transactions are entered into by an employee with Southern Company Services in Birmingham. Correct.

COMMISSIONER SKOP: Okay. So noting that the, where we looked at where there were -- I'm trying to think of the right word -- where there were savings to the ratepayers in that specific month, I mean months in which gas was rising, the hedges were in place, it ultimately saved customers money.

On those other instances of the curve where gas had increased sharply but there were no savings, could that be due to the fact that the hedges were not in place, in place yet to explain that discrepancy that Mr. Moyle was getting to where he asked -- he asked a question about the savings and then noted --

THE WITNESS: Correct.

COMMISSIONER SKOP: -- on subsequent portions of that graph where the data had not shown related savings, if you will, for the, for the same type of event. But I know that the data on the exhibit only goes back to 2006 and doesn't look at, you know, other points in time.

But I think that he, he mentioned, Mr. Moyle, correct me if I'm wrong, looking at specifically one point in time where there was no savings, although gas peaked up. And I think that was in mid 2006 to 2007, I think, was the question that I heard asked. So I was trying to better understand why that could be and whether that might have something to do with the timing of the hedges that were in place at that point in time, if you might be able to elaborate.

THE WITNESS: Well, without actually looking at each individual hedge transaction, just generally what I would say is that many times we enter into hedge positions years in advance of the actual settlement time period. So if indeed we had entered all these hedge transactions, say, in, two thousand -- early 2005 and settled them all in, at the peak, 2006, yes, you would expect to have a fairly large gain. But I just don't know the relationship of when we entered these hedges relative to when they were actually settled.

COMMISSIONER SKOP: Okay. Thank you.

CHAIRMAN GRAHAM: Thank you, Commissioner Skop. Anybody else? Any redirect?

MR. BADDERS: No redirect. I would like to move his exhibits into the record. That would be Exhibit 15, 16, 17 and 18.

CHAIRMAN GRAHAM: We want to move Exhibit 15, 16, 17 and 18. Are there any objections to any of those four? Seeing none, so moved.

(Exhibits 15, 16, 17 and 18 admitted into the record.)

MS. BENNETT: I believe, Mr. Chairman, that Mr. Moyle also had an exhibit for this witness to move into the record.

MR. MOYLE: Yeah. It's 68, I think it was marked, which is the composite exhibit that there's been some discussion on. So I'd go ahead and move that in to make sure the record is clear and captures that.

CHAIRMAN GRAHAM: We also want to move Exhibit 68. Do we have any objection to that?

MR. BADDERS: No objection.

CHAIRMAN GRAHAM: So moved then.

(Exhibit 68 admitted into the record.)

Are we done with this witness?

MR. BADDERS: I believe we are. We would ask that Witness Ball be excused.

CHAIRMAN GRAHAM: Do we have any other questions or foreseeable questions for this witness?

MS. BENNETT: Staff does not.

CHAIRMAN GRAHAM: Mr. Ball, you are now excused. Thank you for coming down.

Mr. Badders.

MR. BADDERS: Yes, Mr. Chairman. The next two witnesses should go fairly quickly. They're both stipulated witnesses for Gulf.

The first one is R. W. Dodd. We would ask that his prefiled direct testimony be entered into the record as though read.

CHAIRMAN GRAHAM: Let's enter Mr. Dodd's prefiled testimony into the record as though it was read.

MR. BADDERS: I also note that he has, I believe it is three exhibits which have been identified as Exhibit 19, 20 and 21. I would move those into the record.

CHAIRMAN GRAHAM: Do we have any objections about Exhibits 19, 20 and 21? Seeing none, let's move those into the record.

(Exhibits 19, 20 and 21 admitted into the record.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 100001-EI
Date of Filing: March 12, 2010

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

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

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

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

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the final true-up amounts for the period January 2009 through December 2009 for both the Fuel and Purchased Power Cost Recovery Clause and the Capacity Cost Recovery Clause. I will also present the actual benchmark level for the calendar year 2010 gains on non-separated wholesale energy sales eligible for a shareholder incentive and the amount of gains or losses from hedging settlements for the period January 2009 through December 2009.

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

A. Yes. My exhibit consists of 1 schedule that relates to the fuel and purchased power cost recovery final true-up, 4 schedules that relate to the capacity cost recovery final true-up, and 1 appendix that includes Schedules A-1 through A-9 and A-12 for the period January 2009 through December 2009, previously filed monthly with this Commission. Each of these documents was prepared under my direction, supervision, or review.

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

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

A. Yes.

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

A. Schedule 1 of my exhibit relates to the fuel and purchased power cost recovery true-up calculation for the period January 2009 through December 2009. In addition, Fuel Cost Recovery Schedules A-1 through A-9 for January 2009 through December 2009 are incorporated herein in Appendix 1.

Q. What is the final fuel and purchased power cost true-up amount related to the period of January 2009 through December 2009 to be refunded or collected through the fuel cost recovery factors in the period January 2011 through December 2011?

A. A net amount to be refunded of $9,959,388 was calculated as shown on Schedule 1 of my exhibit.

Q. How was this amount calculated?

A. The $9,959,388 was calculated by taking the difference in the estimated and actual over-recovery amounts for the period January 2009 through December 2009. The estimated over-recovery was $36,414,908 as shown on Schedule E-1A, Line 1 filed August 4, 2009 and approved in FPSC Order No. PSC-10-0002-FOF-EI issued on January 4, 2010. The actual over-recovery was $46,374,296 which is the sum of the Period-to-Date amounts on lines 7, 8, and 12 shown on the December 2009 Schedule A-2, page 2 of 3, included in Appendix 1. Additional details supporting the approved estimated true-up amount are included on Schedules E1-A and E1-B filed November 2, 2009.

Q. Mr. Dodd, has the benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for actual 2009 gains?

A. Yes, the three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2007 through 2009 is calculated as follows:

Year	Actual Gain
2007	2,599,491
2008	1,228,671
2009	982,077
Three-Year Average	$1,603,413

Q. What is the actual threshold for 2010?

A. The actual threshold for 2010 is $1,603,413.

Q. Is Gulf seeking to recover any gains or losses from hedging settlements for the period of January 2009 through December 2009?

A. Yes. On line 2 of Schedule A-1, Period-to-Date, for December 2009 included in Appendix 1, Gulf has recorded a net loss of $51,232,251 related to hedging activities in 2009. Mr. Ball addresses the details of those hedging activities in his testimony.

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

A. Schedules CCA-1, CCA-2, CCA-3 and CCA-4 of my exhibit relate to the purchased power capacity cost recovery true-up calculation for the period January 2009 through December 2009. In addition, Capacity Cost Recovery Schedule A-12 for the months of January 2009 through December 2009 is included in Appendix 1.

Q. What is the final purchased power capacity cost true-up amount related to the period of January 2009 through December 2009 to be refunded or collected in the period January 2011 through December 2011?

A. An amount to be refunded of $2,618,214 was calculated as shown on Schedule CCA-1 of my exhibit.

Q. How was this amount calculated?

A. The $2,618,214 was calculated by taking the difference in the estimated January 2009 through December 2009 under-recovery of $1,787,568 and the actual over-recovery of $830,646, which is the sum of lines 10 and 11 under the total column of Schedule CCA-2. The estimated true-up amount for this period was approved in FPSC Order No. PSC-09-0795-FOF-EI dated December 2, 2009. Additional details supporting the approved estimated true-up amount are included on Schedules CCE-1A and CCE-1B filed November 2, 2009.

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

A. Schedule CCA-2 shows the calculation of the actual over-recovery of purchased power capacity costs for the period January 2009 through December 2009. Schedule CCA-3 of my exhibit is the calculation of the interest provision on the over-recovery for the period January 2009 through December 2009. This is the same method of calculating interest that is used in the Fuel and Purchased Power (Energy) Cost Recovery Clause and the Environmental Cost Recovery Clause.

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

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

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 100001-EI
Date of Filing: August 2, 2010

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

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

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

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

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

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

A. Yes, I have.

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

Q. Are you familiar with the Fuel and Purchased Power (Energy) estimated true-up calculations for the period of January 2010 through December 2010 and the Purchased Power Capacity Cost estimated true-up calculations for the period of January 2010 through December 2010 set forth in your exhibit?

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

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

A. Yes, I have.

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

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

Q. Mr. Dodd, what has Gulf calculated as the fuel cost recovery true-up to be applied in the period January 2011 through December 2011?

A. The fuel cost recovery true-up for this period is an increase of 0.1236¢/kwh. As shown on Schedule E-1A, this includes an estimated under-recovery for the January through December 2010 period of $23,786,207. It also includes a final over-recovery for the January through December 2009 period of $9,959,388 (see Schedule 1 of Exhibit RWD-1 in this docket filed on March 12, 2010). The resulting total under-recovery of $13,826,819 will be included for recovery during 2011.

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

A. Schedules CCE-1A, CCE-1B and CCE-4 of my exhibit relate to the Purchased Power Capacity Cost true-up calculation to be applied in the January 2011 through December 2011 period.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2011 through December 2011?

A. The true-up for this period is a decrease of 0.0283¢/kwh as shown on Schedule CCE-1A. This includes an estimated over-recovery of $545,466 for January 2010 through December 2010. It also includes a final over-recovery of $2,618,214 for the period of January 2009 through December 2009 (see Schedule CCA-1 of Exhibit RWD-1 in this docket filed March

12, 2010). The resulting total over-recovery of $3,163,680 will be included for refund during 2011.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 100001-EI
Date of Filing: September 1, 2010

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

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

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

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

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

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

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the calculation of Gulf Power's fuel cost recovery factors for the period January 2011 through December 2011. I will also discuss the calculation of the purchased power capacity cost recovery factors for the period January 2011 through December 2011.

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

A. Yes. My exhibit consists of 15 schedules, each of which was prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Dodd's exhibit consisting of 15 schedules, be marked as Exhibit No. _____(RWD-3).

Q. Mr. Dodd, what is the levelized projected fuel factor for the period January 2011 through December 2011?

A. Gulf has proposed a levelized fuel factor of 5.104¢/kwh. This factor is based on projected fuel and purchased power energy expenses for January 2011 through December 2011 and projected kwh sales for the same period, and includes the true-up and GPIF amounts.

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

A. The projected levelized fuel factor for 2011 is .239¢/kwh less or 4.47 percent lower than the levelized fuel factor in place January 2010 through December 2010.

Q. Please explain the calculation of the fuel and purchased power expense true-up amount included in the levelized fuel factor for the period January 2011 through December 2011.

A. As shown on Schedule E-1A of my exhibit, the true-up amount of $13,826,819 to be collected during 2011 includes an estimated under-recovery for the January through December 2010 period of $23,786,207, plus a final over-recovery for the period January through December 2009 of $9,959,388. The estimated under-recovery for the January through December 2010 period includes 6 months of actual data and 6 months of estimated data as reflected on Schedule E-1B.

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of January 2009 through December 2009?

A. The GPIF result is shown on Line 31 of Schedule E-1 as an increase of .0007¢/kwh to the levelized fuel factor, thereby rewarding Gulf $82,250.

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

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

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

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

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

A. Gulf proposes a standard fuel factor, adjusted for line losses, of 5.131¢/kwh for Group A. Fuel factors for Groups A, B, C, and D are shown on Schedule E-1E. These factors have all been adjusted for line losses.

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

A. The time-of-use fuel factors were calculated based on projected loads and system lambdas for the period January 2011 through December 2011. These factors included the GPIF and true-up and were adjusted for line losses. These time-of-use fuel factors are also shown on Schedule E-1E.

Q. How does the proposed fuel factor for Rate Schedule RS compare with the factor applicable to December 2010 and how would the change affect the cost of 1,000 kwh on Gulf's residential rate RS?

A. The current fuel factor for Rate Schedule RS applicable through December 2010 is 5.371¢/kwh compared with the proposed factor of 5.131¢/kwh. For a residential customer who uses 1,000 kwh in January 2011, the fuel portion of the bill would decrease from $53.71 to $51.31.

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

A. Yes. A tabulation of these costs is set forth in Schedule E-11 of my exhibit. These costs represent the estimated averages for the period from January 2011 through December 2011.

Q. What amount have you calculated to be the appropriate benchmark level for calendar year 2011 gains on non-separated wholesale energy sales eligible for a shareholder incentive?

A. In accordance with Order No. PSC-00-1744-AAA-EI, a benchmark level of $1,017,585 has been calculated for 2011 as follows:

2008 actual gains	1,228,671
2009 actual gains	982,077
2010 estimated gains	842,007
Three-Year Average	$1,017,585

This amount represents the minimum projected threshold for 2011 that must be achieved before shareholders may receive any incentive. As demonstrated on Schedule E-6, page 2 of 2, Gulf's projection reflects a credit to customers of 100 percent of the gains on non-separated sales for 2011 for the months of January through December.

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

A. Schedule CCE-1, including CCE-1A and CCE-1B, Schedule CCE-2, and Schedule CCE-4 of my exhibit relate to the calculation of the PPCC recovery factors for the period January 2011 through December 2011.

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

A. Schedule CCE-1 shows the calculation of the amount of capacity payments to be recovered through the PPCC Recovery Clause. Mr. Ball has provided me with Gulf's projected purchased power capacity transactions. Gulf's total projected net capacity expense, which includes a credit for transmission revenue, for the period January 2011 through December 2011 is $50,039,244. The jurisdictional amount is $48,260,759. This amount is added to the total true-up amount to determine the total purchased power capacity transactions that would be recovered in the period.

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

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

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

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

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

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

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

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

A. The purchased power capacity costs recovered through the clause for a residential customer who uses 1,000 kwh will be $4.76.

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

A. The fuel and capacity factors will be effective beginning with Cycle 1 billings in January 2011 and continuing through the last billing cycle of December 2011.

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

A. Yes.

MR. BADDERS: Moving to the next witness, M. A. Young, I would ask that his prefiled direct testimony be entered into the record as though read.

CHAIRMAN GRAHAM: Let's move M. A. Young's prefiled testimony into the record as though read.

MR. BADDERS: We also have two exhibits for Mr. Young. That would be hearing Exhibit 22 and 23. I would move those into the record also.

CHAIRMAN GRAHAM: Do we have any objections to Exhibits 22 or 23? Hearing none, we will move those into the record as well.

(Exhibits 22 and 23 admitted into the record.)

GULF POWER COMPANY

Before the Florida Public Service Commission

Direct Testimony of

M. A. Young, III

Docket No. 100001-EI

Date of Filing: April 1, 2010

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

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

Q. Please describe your educational and business background.

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

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

A. The purpose of my testimony is to present GPIF results for Gulf Power Company for the period of January 1, 2009, through December 31, 2009.

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

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

Counsel: We ask that Mr. Young's Exhibit, consisting of five schedules, be marked for identification as Exhibit No. ______(MAY-1).

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

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

Q. Were average net operating heat rate (ANOHR) targets that include the BTU/LB independent variable approved in FPSC Order No. PSC-99-2512-FOF-EI used for Plant Daniel Units 1 and 2 for this period?

A. Yes. The target heat rate equation for Plant Daniel Unit 2 did include the BTU/LB independent variable originally approved in FPSC Order No. PSC-99-2512-FOF-EI. The BTU/LB variable has been incorporated in previous filings to account for the change in fuel mix at Plant Daniel, which was previously noted in the GPIF Target Filing for 2006 that was submitted to the FPSC on September 16, 2005, as well as the GPIF Results Filing for 2005 that was submitted to the FPSC on April 3, 2006. The use of this BTU/LB variable was evaluated for the change in fuel mix at Plant Daniel, the variable was statistically significant and therefore included in the target heat rate equation for Daniel 2 only.

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

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

A calculation of GPIF availability points based on these availabilities and the targets established by FPSC Order No. PSC-08-0030-FOF-EI is on page 11 of Schedule 2. The results are: Crist 4, +10.00 points; Crist 5, -1.76 points; Crist 6, +10.00 points; Crist 7, +0.74 points; Smith 1, -10.00 points; Smith 2, +3.33 points; Daniel 1, +6.00 points; and Daniel 2, -10.00 points.

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

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

As was done for the prior GPIF periods, and as indicated on pages 10 through 17 of Schedule 3, the target equations were used to adjust actual results to the target basis. These equations, submitted in September 2008, are shown on page 20 of Schedule 3. As calculated on page 21 of Schedule 3, the adjusted actual average net operating heat rates correspond to the following GPIF unit heat rate points: +3.86 for Crist 4, 0.00 for Crist 5, 0.00 for Crist 6, -1.88 for Crist 7, -2.26 for Smith 1, +1.02 for Smith 2, +1.97 for Daniel 1, and +1.72 for Daniel 2.

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

A. Using the unit equivalent availability and heat rate points previously mentioned, along with the appropriate weighting factors, the number of Company points achieved was 0.22 as indicated on page 2 of Schedule 4. This calculated to a reward in the amount of $82,250.

Q. Please summarize your testimony.

A. In view of the adjusted actual equivalent availabilities, as shown on page 11 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 21 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a reward in the amount of $82,250 as provided for by the GPIF plan.

Q. Does this conclude your testimony?
A. Yes.

CHAIRMAN GRAHAM: Does that conclude your case?

MR. BADDERS: Yes. It does, Mr. Chairman.

CHAIRMAN GRAHAM: Thank you, sir.

Okay. Let's go to Mr. Beasley.

MR. BEASLEY: Mr. Chairman, our first three witnesses have been stipulated. If I could move or ask that Mr. Aldazabal's direct testimony be inserted into the record as though read. It's three sets of testimony 2009 true-up, the estimated/actual for 2010 and his projection testimony. And I would ask that that be inserted into the record as though read.

CHAIRMAN GRAHAM: Let's add that into the record as though read.

MR. BEASLEY: And I would move the admission of his exhibits, which are 24, 25 and 26.

CHAIRMAN GRAHAM: Do we have any objection or questions to those exhibits? Seeing none, let's move those into the record as well.

(Exhibits 24, 25 and 26 admitted into the record.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

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

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

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

A. I received a Bachelor of Science Degree in Accounting in 1991, and received a Masters of Accountancy from the University of South Florida in Tampa in 1995. I am a CPA in the State of Florida and have accumulated 15 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, and budgeting and analysis. In April 1999, I joined Tampa Electric as Supervisor, Regulatory

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for the Commission's review and approval, the final true-up amounts for the period January 2009 through December 2009 for the Fuel and Purchased Power Cost Recovery Clause ("fuel clause"), the Capacity Cost Recovery Clause ("capacity clause") as well as the wholesale incentive benchmark for January 2010 through December 2010.

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

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

Q. Have you prepared an exhibit in this proceeding?

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

Capacity Cost Recovery Clause

Q. What is the final true-up amount for the Capacity Cost Recovery Clause for the period January 2009 through December 2009?

A. The final true-up amount for the capacity clause for the period January 2009 through December 2009 is an over-recovery of $21,184.

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

A. Document No. 1, page 1 of 4, entitled "Tampa Electric Company Capacity Cost Recovery Clause Calculation of Final True-up Variances for the Period January 2009

Through December 2009", provides the calculation for the final over-recovery of $21,184. The actual capacity cost under-recovery, including interest, was $28,596,916 for the period January 2009 through December 2009 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the $28,618,100 actual/estimated under-recovery approved in Order No. PSC-09-0795-FOF-EI issued December 2, 2009 in Docket No. 090001-EI, results in a final over-recovery for the period of $21,184 as identified in Document No. 1, page 4 of 4. This over-recovery amount will be applied in the calculation of the capacity cost recovery factors for the period January 2011 through December 2011.

Q. What is the estimated effect of this $21,184 over-recovery for the January 2009 through December 2009 period on residential bills during January 2011 through December 2011?

A. There is no net effect on the 2011 capacity factors as a result of the 2009 over-recovery.

Incremental Security Alert and NERC Cyber Expenses

Q. What were Tampa Electric's actual 2009 incremental O&M security alert and NERC cyber security expenses as a result of the events of September 11, 2001?

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

Fuel and Purchased Power Cost Recovery Clause

Q. What is the final true-up amount for the Fuel and Purchased Power Cost Recovery Clause for the period January 2009 through December 2009?

A. The final fuel clause true-up for the period January 2009 through December 2009 is an over-recovery of $14,108,291. The actual fuel cost over-recovery, including interest, was $59,124,988 for the period January 2009 through December 2009. This $59,124,988 amount, less the $45,016,697 actual/estimated over-recovery amount approved in Order No. PSC-09-0795-FOF-EI, issued December 2, 2009 in Docket No. 090001-EI results in a net over-recovery amount for the period of $14,108,291.

Q. What is the estimated effect of the $14,108,291 over-recovery for the January 2009 through December 2009 period on residential bills during January 2011 through December 2011?

A. The $14,108,291 over-recovery would decrease a 1,000 kWh residential bill by approximately $0.74.

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

A. Document No. 2 is entitled "Tampa Electric Company Final Fuel and Purchased Power Over/(Under) Recovery for the Period January 2009 Through December 2009". It shows the calculation of the final fuel over-recovery of $14,108,291.

Line 1 shows the total company fuel costs of $906,778,795 for the period January 2009 through December 2009. The jurisdictional amount of total fuel costs is $898,970,398, as shown on line 2. This amount is compared to the jurisdictional fuel revenues applicable to the period on line 3 to obtain the actual over-recovered fuel costs for the period, shown on line 4. The resulting $59,222,295 over-recovered fuel costs for the period, combined with the interest, true-up collected and the prior period true-up shown on lines 5, 6 and 7, respectively, constitute the actual over-recovery of $59,124,988 shown on line 8. The $59,124,988 actual over-recovery amount less the $45,016,697 actual/estimated over-recovery amount shown on line 9, results in a final $14,108,291 over-recovery amount for the period January 2009 through December 2009 as shown on line 10.

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

A. Document No. 3 entitled "Tampa Electric Company Calculation of True-up Amount Actual *vs.* Original Estimates for the Period January 2009 Through December 2009", shows the calculation of the actual over-recovery as compared to the estimate for the same period.

Q. What was the total fuel and net power transaction cost variance for the period January 2009 through December 2009?

A. As shown on line A7 of Document No. 3, the fuel and net power transaction cost variance is $138,866,750 less than what was originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2009 through December 2009?

A. As shown on line C3 of Document No. 3, the company collected $52,281,532 or 5.2 percent less jurisdictional fuel revenues than originally estimated.

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

A. Document No. 4 contains a 12-month summary detailing the transactions for each of Commission Schedules A6, A7, A8, A9 and A12 for the period January 2009 through December 2009.

Wholesale Incentive Benchmark

Q. What is Tampa Electric's wholesale incentive benchmark for 2010, as derived in accordance with Order No. PSC-01-2371-FOF-EI, Docket No. 010283-EI?

A. The company's 2010 benchmark is $2,002,890, which is the three-year average of $799,040, $1,676,141 and $3,533,488 actual gains on non-separated wholesale sales, excluding emergency sales, for 2007, 2008 and 2009, respectively.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

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

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

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

A. I received a Bachelor of Science Degree in Accounting in 1991, and received a Masters of Accountancy from the University of South Florida in Tampa in 1995. I am a CPA in the State of Florida and have accumulated 15 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, and budgeting and analysis. In April 1999, I joined Tampa Electric as Supervisor, Regulatory Accounting. In January 2004, I became Manager Regulatory Affairs where my duties included managing cost recovery for fuel and purchased power, interchange sales, and capacity payments. In August 2009, I was promoted to Director Regulatory Affairs with primary responsibility for overseeing all of the cost recovery clauses.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2010 through December 2010 fuel and purchased power and capacity true-up amounts to be recovered in the January 2011 through December 2011 projection period. My testimony addresses the recovery of fuel and purchased power costs as well as capacity costs for the year 2010, based on six months of actual data and six months of estimated data. This information will be used in the determination of the 2011 fuel and purchased power costs and capacity cost recovery factors.

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

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

9, which provide the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2010 through December 2010. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period of January 2010 through December 2010. These documents are furnished as support for the projected true-up amount for this period.

Fuel and Purchased Power Cost Recovery Factors

Q. What has Tampa Electric calculated as the estimated net true-up amount for the current period to be applied in the January 2011 through December 2011 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount applicable for the period January 2011 through December 2011 is an over-recovery of $67,087,873.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2011 through December 2011 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2011 is the sum of the final true-up amount for the period January 2009 through December 2009 and the actual/estimated true-up amount for the period January 2010 through December 2010.

Q. What did Tampa Electric calculate as the final fuel and purchased power cost recovery true-up amount for 2009?

A. The final true-up was an over-recovery of $14,108,291. The actual fuel cost over-recovery, including interest was $59,124,988 for the period January 2009 through December 2009. The $59,124,988 amount, less the actual/estimated over-recovery amount of $45,016,697 approved in Order No. PSC-09-0795-FOF-EI, issued December 2, 2009 in Docket No. 090001-EI resulted in a net over-recovery amount for the period of $14,108,291.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2010 through December 2010?

A. The actual/estimated fuel and purchased power cost recovery true-up is an over-recovery amount of $52,979,582 for the January 2010 through December 2010 period. The detailed calculation supporting the actual/estimated current period true-up is shown in Exhibit No. ____ (CA-2), Document No. 1 on Schedule E1-B.

Capacity Cost Recovery Clause

Q. What has Tampa Electric calculated as the estimated net true-up amount to be applied in the January 2011 through December 2011 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January 2011 through December 2011 is an under-recovery of $53,091 as shown in Exhibit No. ____ (CA-2), Document No. 2, page 2 of 5.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2011 through December 2011 capacity cost recovery factors?

A. The net true-up amount to be recovered in the 2011 capacity cost recovery factors is the sum of the final true-up amount for 2009 and the actual/estimated true-up amount for January 2010 through December 2010.

Q. What did Tampa Electric calculate as the final capacity cost recovery true-up amount for 2009?

A. The final 2009 true-up is an over-recovery of $21,184. The actual capacity cost under-recovery including interest was $28,596,916 for the period January 2009 through December 2009. The $28,596,916 amount, less the actual/estimated under-recovery amount of $28,618,100 approved in Order No. PSC-09-0795-FOF-EI issued December 2, 2009 in Docket No. 090001-EI results in a net over-recovery amount for the period of $21,184 as identified in Exhibit No. ____ (CA-2), Document No. 2, page 1 of 5.

Q. What did Tampa Electric calculate as the actual/estimated capacity cost recovery true-up amount for the period January 2010 through December 2010?

A. The actual/estimated true-up amount is an under-recovery of $74,275 as shown on Exhibit No. ____ (CA-2), Document No. 2, page 1 of 5.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

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

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

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

A. I received a Bachelor of Science Degree in Accounting in 1991, and received a Masters of Accountancy in 1995 from the University of South Florida in Tampa. I am a CPA in the State of Florida and have accumulated 15 years of electric utility experience working in the areas of fuel and interchange accounting, surveillance reporting, and budgeting and analysis. In April 1999, I joined Tampa Electric as Supervisor, Regulatory Accounting. In January 2004, I became Manager, Regulatory Affairs where my duties included managing cost recovery for fuel and purchased power, interchange sales, and capacity payments. In August 2009, I was promoted to Director Regulatory Affairs with primary responsibility for overseeing all cost recovery clauses.

Q. Have you previously testified before this Commission?

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, the proposed annual levelized fuel and purchased power cost recovery factors including an inverted or two-tiered residential fuel charge to encourage energy efficiency and conservation and the projected wholesale incentive benchmark for January 2011 through December 2011. I will also describe significant events that affect the factors and provide an overview of the composite effect from the various cost recovery factors for 2011.

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

A. Yes. Exhibit No. ____ (CA-3), consisting of three documents, was prepared under my direction and supervision. Document No. 1, consisting of four pages, is furnished as support for the projected capacity cost recovery factors utilizing the Commission approved allocation methodology from Order No. PSC-09-0283-FOF-EI issued April 30, 2009, in Docket No. 080317-EI based on 12 Coincident Peak ("CP") and 25 percent Average Demand ("AD"). Document No. 2, which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, is comprised of Schedules E1 through E10 for January 2011 through December 2011 as well as Schedule H1 for January through December, 2008 through 2011. Document No. 3 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate and a levelized fuel rate, which demonstrates that the tiered rate is revenue neutral.

Capacity Cost Recovery

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

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

Q. Please describe the changes to the 2011 capacity cost recovery factors related to Tampa Electric's approved rate design approved in Order No. PSC-09-0283-FOF-EI.

A. As a result of Tampa Electric's base rate case, the Commission approved the consolidation of the company's General Service - Demand ("GSD") and General Service - Large Demand ("GSLD") rate customers into one new GSD rate class. Additionally, the allocation of production demand costs was modified to the 12 CP and 25 percent AD to better reflect cost causation. The Commission also approved the recovery of capacity costs through a factor applied to billed kW demand for demand-measured customers because that recovery method would be consistent with the recovery of production plant that otherwise would have been built.

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

A. Tampa Electric is requesting recovery of capacity payments for power purchased for retail customers, excluding optional provision purchases for interruptible customers, through the capacity cost recovery factors.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2011 through December 2011.

A.

Rate Class and Metering Voltage	Capacity Cost Cents per kWh	Recovery Factor Cents per kW
RS Secondary	0.336	
GS and TS Secondary	0.294	
GSD, SBF Standard		
Secondary		1.07
Primary		1.06
Transmission		1.05
IS, IST, SBI		

Primary		0.87
Transmission		0.86
GSD Optional		
Secondary	0.255	
Primary	0.253	
LS1 Secondary	0.078	

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

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.291 cents per kWh compare to the factor for January 2010 through December 2010?

A. The proposed capacity cost recovery factor is 0.181 cents per kWh (or $1.81 per 1,000 kWh) lower than the average capacity cost recovery factor of 0.472 cents per kWh for the January 2010 through December 2010 period.

Fuel and Purchased Power Cost Recovery Factor

Q. What is the appropriate amount of the levelized fuel and purchased power cost recovery factor for the year 2011?

A. The appropriate amount for the 2011 period is 4.225 cents per kWh before any application of time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. ____ (CA-3), Document No. 2, shows the appropriate value for the total fuel and purchased power cost recovery factor for each metering voltage level as projected for the period January 2011 through December 2011.

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

A. The Generating Performance Incentive Factor ("GPIF") and true-up factors are provided on Schedule E1-C. Tampa Electric has calculated a GPIF reward of $1,830,855, which is included in the calculation of the total fuel and purchased power cost recovery factors. Additionally, E1-C indicates the net true-up amount for the January 2010 through December 2010 period. The net true-up amount for this period is an over-recovery of $67,087,873.

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

A. Schedule E1-D presents Tampa Electric's on-peak and off-peak fuel adjustment factors for January 2011 through

December 2011. The schedule also presents Tampa Electric's levelized fuel cost factors at each metering voltage level.

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

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

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

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

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for January 2011 through December 2011.

A.

Metering Voltage Level	**Fuel Charge Factor (cents per kWh)**
Secondary	4.225
Tier I (Up to 1,000 kWh)	3.875
Tier II (Over 1,000 kWh)	4.875
Distribution Primary	4.183
Transmission	4.141
Lighting Service	4.134
Distribution Secondary	4.817 (on-peak)
	3.994 (off-peak)
Distribution Primary	4.769 (on-peak)
	3.954 (off-peak)
Transmission	4.721 (on-peak)
	3.914 (off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 4.225 cents per kWh compare to the levelized fuel adjustment factor for the January 2010 through December 2010 period?

A. The proposed fuel charge factor is 0.292 cents per kWh (or $2.92 per 1,000 kWh) lower than the average fuel charge factor of 4.517 cents per kWh for the January 2010 through December 2010 period.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2011 fuel and purchased power and capacity cost recovery projections?

A. Yes. There are two significant events. These are 1) the continued decline in natural gas prices and related hedge results; and 2) the expiration of two existing firm purchase power cogeneration agreements with Hillsborough County and the City of Tampa.

Q. Please describe the first event that affects the company's projection filing.

A. With the addition of Bayside Station in 2004 and more recently the combustion turbines ("CT's") at Polk, Bayside and Big Bend Stations, Tampa Electric has increased its reliance on natural gas as a fuel source. In the fall of 2008 the prolonged economic downturn resulted in a dramatic decline in fuel commodity prices, particularly natural gas, which has resulted in a significant decrease in fuel and purchased power costs. In order to minimize fuel price volatility and comply with the company's Commission approved Risk Management Plan, financial hedges were entered into for natural gas in 2010 and 2011 which have partially mitigated some of that benefit. Witness J. T. Wehle's direct testimony describes the decrease in natural gas costs and associated hedge results in more detail.

Q. Please describe the second event.

A. Entering 2010 Tampa Electric had firm purchase power agreements with Hillsborough County for 23 MW and the City of Tampa for 19 MW, respectively. On March 1, 2010, the Hillsborough County agreement expired as both the County and Tampa Electric were unable to reach agreement on terms that would be acceptable to both parties. Similarly, Tampa Electric and the City of Tampa agreed to mutually terminate a December 2008 renegotiated extension of their agreement beyond August 1, 2011 when the parties were unable to successfully renegotiate some of the terms of that extension. The expiration of both agreements results in a significant reduction in capacity costs as well as a reduction in as-available energy payments.

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric's projected wholesale incentive benchmark for 2011?

A. The company's projected 2011 benchmark is $2,325,363, which is the three-year average of $1,676,141, $3,533,488 and $1,766,461 in gains on the company's non-separated wholesale sales, excluding emergency sales, for 2008, 2009 and 2010 (estimated/actual), respectively.

Q. Does Tampa Electric expect gains in 2011 from non-separated wholesale sales to exceed its 2011 wholesale incentive benchmark?

A. No. Tampa Electric anticipates that sales will not exceed the projected benchmark for 2011. Therefore, all sales margins will flow back to customers.

Cost Recovery Factors

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

A. The composite effect on a residential bill for 1,000 kWh is a decrease of $5.22 beginning January 2011. These charges are shown in Exhibit No. ____ (CA-3), Document No. 2, on Schedule E10.

Q. When should the new rates go into effect?

A. The new rates should go into effect concurrent with meter reads for the first billing cycle for January 2011.

Q. Does this conclude your testimony?

A. Yes, it does.

MR. BEASLEY: The next Tampa Electric witness is also stipulated, Mr. Brian S. Buckley. I would like to move or ask that his direct testimony be inserted into the record as though read. That's his true-up and projection testimony for the generating performance incentive factor.

CHAIRMAN GRAHAM: Let's enter Mr. Buckley's record -- I'm sorry -- testimony, prefiled testimony into the record as though, as though it was read.

MR. BEASLEY: Thank you. And I would also move his Exhibits 27 and 28 into the record.

CHAIRMAN GRAHAM: If we don't have any objections to 27 and 28, then we will move those as well into the record.

(Exhibits 27 and 28 admitted into the record.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 100001-EI
FILED: 04/01/2010

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

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

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

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Tampa Electric's actual performance results from unit equivalent availability and station heat rate used to determine the Generating Performance Incentive Factor ("GPIF") for the period January 2009 through December 2009. I will also compare these results to the targets established prior to the beginning of the period.

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

A. Yes, I prepared Exhibit No. _____ (BSB-1), consisting of two documents. Document No. 1, entitled "Tampa Electric Company, Generating Performance Incentive Factor, January 2009 - December 2009 True-up" is consistent with the GPIF Implementation Manual previously approved by the Commission. Document No. 2 provides the company's Actual Unit Performance Data for the 2009 period.

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

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

Q. Have you calculated the results of Tampa Electric's performance under the GPIF during the January 2009 through December 2009 period?

A. Yes, I have. This is shown on Document No. 1, page 4 of 32. Based upon 2.486 Generating Performance Incentive Points ("GPIP"), the result is a reward amount of $1,830,855 for the period.

Q. Please proceed with your review of the actual results for the January 2009 through December 2009 period.

A. On Document No. 1, page 3 of 32, the actual average common equity for the period is shown on line 14 as $1,820,026,462. This produces the maximum penalty or reward amount of $7,365,753 as shown on line 21.

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

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

Q. Are the actual equivalent availability results shown on Document No. 1, page 6 of 32, column 2, directly applicable to the GPIF table?

A. No. Adjustments to actual equivalent availability may be required as noted in section 4.3.3 of the GPIF Manual. The actual equivalent availability including the required adjustment is shown on Document No. 1, page 6 of 32, column 4. The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the Commission's Staff. The adjustments for each unit are as follows:

Big Bend Unit No. 1

On this unit, 816.0 planned outage hours were originally scheduled for 2009. Actual outage activities required 1228.6 planned outage hours. Consequently, the actual equivalent availability of 55.7 percent is adjusted to 58.7 percent as shown on Document No. 1, page 7 of 32.

Big Bend Unit No. 2

On this unit, 2856.0 planned outage hours were originally scheduled for 2009. Actual outage activities required 2320.7 planned outage hours. Consequently, the actual equivalent availability of 36.8 percent is adjusted to 33.8 percent as shown on Document No. 1, page 8 of 32.

Big Bend Unit No. 3

On this unit, 336.0 planned outage hours were originally scheduled for 2009. Actual outage activities required 441.4 planned outage hours. Consequently, the actual equivalent availability of 78.8 percent is adjusted to 79.8 percent as shown on Document No. 1, page 9 of 32.

Big Bend Unit No. 4

On this unit, 1344.0 planned outage hours were originally scheduled for 2009. Actual outage activities required 416.2 planned outage hours. Consequently, the actual equivalent availability of 79.5 percent is adjusted to 70.7 percent as shown on Document No. 1, page 10 of 32.

Polk Unit No. 1

On this unit, 854.1 planned outage hours were originally scheduled for 2009. Actual outage activities required 1232.4 planned outage hours. Consequently, the actual equivalent availability of 76.5 percent is adjusted to 80.3 percent, as shown on Document No. 1, page 11 of 32.

Bayside Unit No. 1

On this unit, 336.0 planned outage hours were originally scheduled for 2009. Actual outage activities required 492.2 planned outage hours. Consequently, the actual equivalent availability of 93.2 percent is adjusted to 95.0 percent, as shown on Document No. 1, page 12 of 32.

Bayside Unit No. 2

On this unit, 336.0 planned outage hours were originally scheduled for 2009. Actual outage activities required 589.7 planned outage hours. Consequently, the actual equivalent availability of 92.0 percent is adjusted to 94.8 percent, as shown on Document No. 1, page 13 of 32.

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

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

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

A. The actual heat rate and adjusted actual heat rate for Tampa Electric's seven GPIF units are shown on Document No. 1, page 6 of 32. The adjustment was developed based on the guidelines of section 4.3.16 of the GPIF Manual. This procedure is further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the FPSC Staff. The final adjusted actual heat rates are also shown on page 5 of 32, column 9. The heat rate value is entered into the respective GPIP table for the particular unit, shown on pages 14 through 20 of 32. Page 4 of 32 summarizes the weighted heat rate points to be awarded or penalized.

Q. What is the overall GPIP for Tampa Electric for the January 2009 through December 2009 period?

A. This is shown on Document No. 1, page 2 of 32. Essentially, the weighting factors shown on page 4 of 32, column 3, plus the equivalent availability points and the heat rate points shown on page 4 of 32, column 4, are substituted within the equation found on page 32 of 32. The resulting value, 2.486, is then entered into the GPIF table on page 2 of 32. Using linear interpolation, the reward amount is $1,830,855.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 100001-EI
FILED: 9/1/2010

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

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

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

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

Q. What is the purpose of your testimony?

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

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

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

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

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

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

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

Q. Did Tampa Electric identify any outages as outliers?

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

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

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

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

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

To give an example for the 2011 period, the projected EUOF for Big Bend Unit 3 is 11.3 percent, and the POF is 6.6 percent. Therefore, the target EAF for Big Bend Unit 3 equals 82.1 percent or:

$$100\% - (11.3\% + 6.6\%) = 82.1\%$$

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

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

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

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

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

$$EAF_{MAX} = 1 - [0.8 \ (11.3\%) + 0.95 \ (6.6\%)] = 84.7\%$$

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

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

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

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

Again, continuing with the Big Bend Unit 3 example,

$$EAF_{MIN} = 1 - [1.40 \ (11.3\%) + 1.10 \ (6.6\%)] = 76.9\%$$

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

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

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

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

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

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

A. For each unit the most current 12-month ending value, June 2011, was used as a basis for the projection. All projected factors are based upon historical unit performance unless adjusted for outlying forced outages. These target factors are additive and result in a EUOF of 11.3 percent for Big Bend Unit 3. The EUOF for Big Bend Unit 3 is verified by the data shown on page 16, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

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

Or

$$EUOF = \frac{(702 + 292)}{8,760} \times 100\% = 11.3\%$$

Relative to Big Bend Unit 3, the EUOF of 11.3 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Big Bend Unit 1

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

Big Bend Unit 2

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

Big Bend Unit 3

The projected EUOF for this unit is 11.3 percent. The unit will have a planned outage in 2011, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 82.1 percent.

Big Bend Unit 4

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

Polk Unit 1

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

Bayside Unit 1

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

Bayside Unit 2

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

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 74.2 percent is shown on Page 5 of Document No. 1. This target is greater than the 2007, 2008 and 2009 January through December actual performances.

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

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

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

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

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

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

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

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

Q. How were these targets determined?

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

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

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

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

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

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

A. The heat rate target for Big Bend Unit 1 is 10,676 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±431 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,350 Btu/Net kWh with a range of ±410 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,582 Btu/Net kWh, with a range of ±404 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,538 Btu/Net kWh with a range of ±384 Btu/Net kWh. The heat rate target for Polk Unit 1 is 9,820 Btu/Net kWh with a range of ±703 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,212 Btu/Net kWh with a range of ±93 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,311 Btu/Net kWh with a range of ±89 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within the range for each target. This is shown on page 4, and pages 7 through 13 of Document No. 1.

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

A. Yes.

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

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

After all of the individual savings are calculated, column 4 totals $29,671,000 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing individual savings by the total. For Big Bend Unit 3, the weighting factor for equivalent availability is 6.2 percent as shown in the right-hand column on page 6. Pages 7 through 13 of Document No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, on Big Bend Unit 3, page 9, if the unit operates at 84.7 percent equivalent availability, fuel savings would equal $1,833,900, and 10 equivalent availability points would be awarded.

The GPIF Reward/Penalty table on page 2 is a summary of the tables on pages 7 through 13. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, or $29,671,000. The right hand column of page 2 is the estimated reward or penalty based upon performance.

Q. How was the maximum allowed incentive determined?

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

Q. Are there any other constraints set forth by the

Commission regarding the magnitude of incentive dollars?

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

Q. Please summarize your testimony.

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

$$\begin{aligned} GPIP: = (& 0.0458\ EAP_{BB1} + 0.0595\ EAP_{BB2} \\ & + 0.0618\ EAP_{BB3} + 0.0788\ EAP_{BB4} \\ & + 0.0067\ EAP_{PK1} + 0.0134\ EAP_{BAY1} \\ & + 0.0032\ EAP_{BAY2} + 0.1138\ HRP_{BB1} \\ & + 0.0963\ HRP_{BB2} + 0.1160\ HRP_{BB3} \\ & + 0.1248\ HRP_{BB4} + 0.1559\ HRP_{PK1} \\ & + 0.0492\ HRP_{BAY1} + 0.0748\ HRP_{BAY2}) \end{aligned}$$

Where:

GPIP = Generating Performance Incentive Points.

EAP = Equivalent Availability Points awarded/

deducted for Big Bend Units 1, 2, 3, and 4, Polk Unit 1 and Bayside Units 1 and 2.

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

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

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

Q. Does this conclude your testimony?

A. Yes.

MR. BEASLEY: The final stipulated witness for Tampa Electric is Mr. Benjamin F. Smith. I would like to request that his projection testimony be inserted into the record as though read.

CHAIRMAN GRAHAM: We will insert Mr. Smith's testimony into the record as though read.

MR. BEASLEY: And he does not have an exhibit.

TAMPA ELECTRIC COMPANY
DOCKET NO. 100001-EI
FILED: 9/1/2010

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH II

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. Please describe Tampa Electric's 2010 wholesale energy purchases.

A. Tampa Electric assessed the wholesale power market and entered into short-term and long-term purchases based on price and availability of supply. Approximately 8 percent of the expected energy needs for 2010 will be met using purchased power. This purchased power energy includes economy purchases and existing firm purchased power agreements with Hardee Power Partners, qualifying facilities, Calpine, RRI Energy Services (formally known as Reliant), and Pasco Cogen. The testimony in previous years describes each existing firm purchased power agreement, which were subsequently approved by the

Commission as being cost-effective for Tampa Electric customers. Hillsborough County chose not to extend the sale of its firm capacity and energy from its waste facility to Tampa Electric as of March 2010. All of the aforementioned purchases provide supply reliability and help reduce fuel price volatility.

Q. Has Tampa Electric entered into any other wholesale energy purchases for 2010 and beyond?

A. No. However, the company projects approximately 6 percent of the expected energy needs for 2011 will be met using economy purchases and existing purchased power agreements. This projection includes energy from both the Calpine and City of Tampa firm purchased power agreements through their respective 2011 contract end dates. The Calpine agreement for firm peaking capacity and energy expires May 2011, and the City of Tampa agreement for firm capacity and energy out of its waste facility expires August 2011. 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. Does Tampa Electric engage in physical or financial hedging of its wholesale energy transactions to mitigate wholesale energy price volatility?

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

Q. Does Tampa Electric's risk management strategy for power transactions adequately mitigate price risk for purchased power for 2010?

A. Yes, Tampa Electric expects its physical wholesale purchases to continue to reduce its customers' purchased power price risk. For example, the 170 MW Calpine purchase and the 158 MW purchase from Reliant in 2010 are reliable, cost-based call options for peaking power. These purchases serve as both a physical hedge and reliable source of economical power in 2010. The availability of these purchases is high, and their price structures provide some protection from rising market prices, which are largely influenced by supply and the volatility of natural gas prices.

Mitigating price risk is a dynamic process and Tampa Electric continually evaluates its options in light of changing circumstances and new opportunities. Tampa Electric also strives to maintain an optimum level and mix of short- and long-term capacity and energy purchases to augment the company's own generation for the year 2010 and beyond.

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

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

Q. Please describe Tampa Electric's wholesale energy sales for 2010 and 2011.

A. Tampa Electric entered into various non-firm, non-separated wholesale sales in 2010, and the company anticipates making additional non-separated sales during the balance of 2010 and in 2011. In accordance with Order No. PSC-01-2371-FOF-EI, issued on December 7, 2001 in Docket No. 010283-EI, all gains from non-separated sales are returned to customers through the fuel clause, up to the three-year rolling average threshold. For all gains above the three-year rolling average threshold, customers receive 80 percent and the company retains the remaining 20 percent. In 2010, Tampa Electric anticipates its gains from non-separated wholesale sales to be $1,766,461, of which 100 percent would flow back to customers since they are less than the three-year rolling average threshold of $2,002,890. Similarly, in 2011, the company's projected gains from non-separated wholesale sales are $771,637, of which 100 percent would flow back to customers since they are less than the projected 2011 three-year rolling average threshold of $2,325,363.

Q. Please summarize your testimony.

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

Q. Does this conclude your testimony?

A. Yes.

MR. BEASLEY: So that brings us to Ms. Joann Wehle.

CHAIRMAN GRAHAM: Now Ms. Wehle was here earlier?

MR. BEASLEY: Yes.

CHAIRMAN GRAHAM: Welcome, Ms. Wehle.

THE WITNESS: Thank you.

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 and your business address.

A My name is Joann Wehle. My business address is Tampa Electric Company, 702 North Franklin Street, Tampa, Florida 33602.

Q Have your duties changed since your filed your true-up and projection testimonies?

A Pardon me. Yes, they have.

Q And what are they now?

A I accepted a new position about a month ago with, with the electric company for a sales and marketing position for the utilities.

Q Thank you. Ms. Wehle, do you have any corrections to make to your April 1, 2010, final true-up testimony?

A Pardon me. Yes, I do. Actually on page 3 of my testimony, line 20, the number that is mentioned there for $184 million should read $193 million.

Q With that change and the change that you described in your, in your position with the Company, if I were to ask you the questions contained in your final true-up testimony, would your answers be the same?

A Yes, they would.

MR. BEASLEY: I would ask that Ms. Wehle's projection, or, excuse me, true-up testimony be inserted red into the record as though read.

CHAIRMAN GRAHAM: Let's move Ms. Wehle's testimony, prefiled testimony into the record as though it were read.

BY MR. BEASLEY:

Q Did you also file and submit on September 1, 2010, projection testimony of Joann T. Wehle?

A Yes, I did.

Q Except for the change in your position, if I asked you the questions contained in that testimony, would your answers be the same?

A Yes, they would.

MR. BEASLEY: I would ask that Ms. Wehle's projection testimony be inserted into the record as though read.

CHAIRMAN GRAHAM: Let's also insert that into the record as if it were read.

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 2009 results of Tampa Electric's risk management activities, as required by the terms of the stipulation entered into by the parties to Docket No. 011605-EI and approved by the Commission in Order No. PSC-02-1484-FOF-EI.

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

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

Q. What were the results of Tampa Electric's risk management activities in 2009?

A. As outlined in Tampa Electric's annual Risk Management Plan, most recently filed on April 1, 2010 in Docket No. 100001-EI, the company follows a non-speculative risk management strategy 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. Over time, the program has been enhanced as Tampa Electric's gas needs have evolved and grown. All enhancements have been reviewed and approved by the company's Risk Authorization Committee.

On April 1, 2010, Tampa Electric filed its annual risk management report, which describes the outcomes of its 2009 risk management activities. The report indicates that Tampa Electric's 2009 hedging activities resulted in a net loss of approximately $~~184~~ 193 million. Tampa Electric followed the plan objective of reducing price volatility while maintaining a reliable fuel supply. A dramatic drop in natural gas prices began in the middle of 2008 and continued to decrease due to lower demand as a result of the recession and higher supply from noncommercial production.

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

A. Yes, Tampa Electric maintains contracts for gas supplies from various regions and on different pipelines to enhance its physical gas supply reliability. Tampa Electric has contracted for pipeline capacity to access the non-conventional shale gas production which is less sensitive to interruption by hurricanes. Tampa Electric also has incremental storage capacity in Bay Gas Storage's new cavern that is currently under development.

Q. Does Tampa Electric use a hedging information system?

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

REDACTED

also used for contract, credit management and risk exposure analysis.

Q. What were the results of the company's incremental hedging activities in 2009?

A. Tampa Electric's incremental natural gas hedging activities protected customers from price volatility for [redacted] percent of the natural gas used in the company's generating stations. As previously mentioned, The net result of natural gas hedging activity in 2009 was a loss of approximately $184 million, when the instrument prices were compared to market prices on settled positions.

Q. Did the company use financial hedges for other commodities in 2009?

A. No, Tampa Electric did not use financial hedges for other commodities primarily because of its fuel mix.

Tampa Electric's generation is comprised mostly of coal and natural gas. Though the price of coal has increased, it is relatively stable compared to the prices of oil and natural gas. In addition, financial hedging instruments for the primary coal Tampa Electric burns, high sulfur Illinois Basin coal, do not exist.

Tampa Electric consumes a small amount of oil. However, its low and erratic usage pattern makes price hedging of oil consumption 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 for power in Florida.

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

A. Yes, Tampa Electric used physical hedges in managing its coal supply reliability. The company enters into a portfolio of differing term contracts with various suppliers to obtain the types of coal used on its system. Additionally, Tampa Electric fills its oil tanks prior to entering hurricane season to reduce exposure to supply or price issues that may arise during hurricane season. In 2009, Tampa Electric added rail delivery capability for coal to Big Bend Station. The addition of rail to the already existing waterborne transportation methods enhances Tampa Electric's access to coal supply and increases the reliability.

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-EI 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. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 100001-EI
FILED: 09/01/2010

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 2011 risk management plan submitted on August 2, 2010 in this docket.

Q. Have you previously testified before this Commission?

A. Yes. I have testified or filed testimony before this Commission in several dockets, including Docket No. 011605-EI, 031033-EI and 080317-EI as well as the annual fuel and purchased power cost recovery dockets from 2001 through 2009. 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.

2011 Fuel Mix and Procurement Strategies

Q. What fuels will Tampa Electric's generating stations use in 2011?

A. In 2011, Tampa Electric expects its fuel mix to be comparable to 2010. In 2011, natural gas-fired and coal-fired generation is expected to be 40 percent and 60 percent of total generation, respectively. Generation from No. 2 oil is less than one percent of the total expected generation.

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

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

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

A. Tampa Electric receives natural gas via the Florida Gas Transmission ("FGT") pipeline and Gulfstream Natural Gas System, LLC ("Gulfstream"). The ability to deliver natural gas directly from two pipelines enhances the fuel delivery reliability of the Bayside Power Station, the largest natural gas units on Tampa Electric's system.

Natural gas can also be delivered to Big Bend Station directly from Gulfstream to support the new aero derivative combustion turbine.

Q. Will there be any changes to Tampa Electric's pipeline capacity for the balance of 2010 or 2011?

A. Yes. Tampa Electric has contracted for FGT Phase VIII capacity. Tampa Electric has reserved an additional 45,000 MMBtu of winter only capacity beginning in November 2010 and an additional 50,000 MMBtu beginning in April of 2011. The Phase VIII capacity provides enhanced reliability delivery of gas supply and allows Tampa Electric to meet its peak system demands.

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

A. Tampa Electric has maintained natural gas storage capacity with Bay Gas Storage near Mobile, Alabama since 2005. Currently the company reserves 850,000 MMBtu of storage capacity, which enhances access to natural gas in the case of severe weather or other events that disrupt supply. Tampa Electric's storage capacity at Bay Gas Storage will increase to 1,200,000 MMBtu when the fourth cavern is completed in the fall 2011.

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

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

Q. 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 petroleum coke and low sulfur coal. The plants have varying operational and environmental restrictions and require fuel with custom quality characteristics such as ash, fusion temperature, sulfur, heat content and chlorine. Since coal is not a homogenous product, fuel selection is based on these unique characteristics, along with price, availability, deliverability and creditworthiness of the supplier.

Tampa Electric maintains a portfolio of bilateral contracts varying in term lengths of long, intermediate, and short 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 the company in monitoring the coal market and shaping the company's coal procurement strategy to reflect current market conditions. This allows for stable supply 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.

Q. Has Tampa Electric entered into coal and natural gas supply transactions for 2011 delivery?

A. Yes, Tampa Electric has contracted over half of its 2011 expected coal needs through bilateral agreements with coal suppliers to mitigate price volatility and ensure reliability of supply. Additionally, the majority of the company's 2011 expected natural gas requirements are already under contract. Tampa Electric anticipates the remaining purchases will be procured by the fourth quarter of 2010 or in the spot market.

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

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

Coal Transportation Costs

Q. Are there any changes to Tampa Electric's coal transportation portfolio in 2011?

A. Yes. In 2009, Tampa Electric completed a rail delivery and unloading facility at Big Bend Station and rail deliveries commenced in December of 2009. Tampa Electric expects to receive 1.8 and 2.1 million tons of coal for use at Big Bend and Polk Stations through this rail facility in 2010 and 2011, respectively.

As part of the CSX transportation agreement, Tampa Electric receives a per ton reimbursement for each ton of coal delivered, all of which is flowed through to customers through the fuel and purchased power cost recovery clause pursuant to the company's most recent rate case final order. Tampa Electric anticipates these amounts to be $13.5 million and $8.4 million for 2010 and 2011, respectively.

Q. What benefits exist from rail transportation of coal for Tampa Electric and its customers?

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

Q. Did the Commission agree that there are customer benefits associated with bi-modal waterborne and rail deliveries?

A. Yes. In the 080001 Docket, the Commission determined that the company complied with all requirements of Order No. PSC-04-0999-FOF-EI in procuring its fuel transportation contracts, which required a fair and open competitive procurement process to ensure the lowest possible delivered costs through the use of a bimodal fuel delivery system.

Projected 2011 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 Wood Mackenzie, 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 form the basis of the natural gas and No. 2 oil market commodity price forecasts. The commodity price projections are then adjusted to incorporate expected transportation costs and location differences.

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

Q. How do the 2011 projected fuel prices compare to the fuel prices projected for 2010?

A. Projected fuel prices are expected to increase slightly in 2011 compared to 2010 as the global economy is projected to improve and inventory surpluses diminish.

Q. What are the market drivers of the expected 2011 price of natural gas?

A. The current market forecasts are projecting a slight increase to natural gas pricing in 2011 as compared to 2010. Once again, an improving economy and market adjustment to shale gas production is expected to raise the price slightly but not dramatically.

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

A. Coal prices dropped dramatically in 2009 as the global economy deteriorated and inventories rose. Additionally, low natural gas prices caused higher cost coal-fired generation to be displaced by lower cost natural gas combined cycle units. The reduced demand for coal caused inventories to increase throughout the nation. Recently, international demand for coal has increased and inventories are beginning to decline. These changes should lead to small increases in coal pricing.

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

A. Yes. Tampa Electric prepared a scenario in which the forecasted fuel prices were 30 percent higher for both natural gas and No. 2 oil. Similarly, Tampa Electric prepared a scenario in which the forecasted fuel prices were 30 percent lower for both natural gas and No. 2 oil.

Risk Management Activities

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

A. Tampa Electric complies with its risk management plan as approved by the company's Risk Authorizing Committee. Tampa Electric's plan is described in detail in the Risk Management plan filed August 2, 2010 in this docket.

Q. Has Tampa Electric used financial hedging in an effort to help mitigate the price volatility of its 2010 and 2011 natural gas requirements?

A. Yes. Tampa Electric hedged a significant portion of its 2010 natural gas supply needs and a portion of its expected 2011 natural gas supply needs in accordance with its plan. Tampa Electric will continue to take advantage of available natural gas hedging opportunities in an effort to benefit its customers, while complying with the company's approved Risk Management Plan. The current market position for natural gas hedges was provided in the Risk Management Plan submitted on August 2, 2010.

Q. Are the company's strategies adequate for mitigating price risk for Tampa Electric's 2010 and 2011 natural gas purchases?

A. Yes, the company's strategies are adequate for mitigating price risk for Tampa Electric's natural gas purchases. Tampa Electric's strategies balance the desire for reduced price volatility and reasonable cost with the uncertainty of natural gas volumes. These strategies are described in detail in Tampa Electric's Risk Management Plan filed August 2, 2010.

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

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

Q. Were Tampa Electric's efforts through July 31, 2010 to mitigate price volatility through its non-speculative hedging program prudent?

A. Yes. Tampa Electric has executed hedges according to the risk management plan filed with this Commission, which was approved by the company's Risk Authorizing Committee. On April 1, 2010, the company filed its 2009 hedging results as part of the final true-up process. Additionally, the Commission Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, requires the utilities to file a Hedging Information Report showing the results of hedging activities from January through July of the current year. The Hedging Information Report facilitates prudence reviews through July 31 of the current year and allows for the Commission's prudence determination at the annual fuel hearing. Tampa Electric filed its Hedging Information Report showing the results of its prudent hedging activities from January through July 2010 in this docket on August 16, 2010.

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

A. No. The primary objective of the company's hedging program is to reduce fuel price volatility as approved by the Commission. Tampa Electric employs a well-disciplined hedging program. This discipline requires consistent hedging based on expected needs and avoidance of speculative hedging strategies aimed at out-guessing the market. This discipline insures hedges will be in place should prices spike and also means hedges are in place when prices decline. Using this disciplined approach means that much of the volatility and uncertainty in natural gas prices are removed from the fuel cost used to generate electricity for our customers.

Q. Does this conclude your testimony?

A. Yes, it does.

BY MR. BEASLEY:

Q Ms. Wehle, could you please summarize your testimonies?

A Yes. Thank you.

Good afternoon, Commissioners. My name is Joann Wehle, and although I was recently promoted to a different position within Tampa Electric, I remain the sponsor of the testimony before you today prepared by myself as 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. My testimony supports the prudence of Tampa Electric's actions to mitigate price volatility as reported in the Company's April 2010 and August 2010 hedging reports, as well as the appropriateness of Tampa Electric's 2011 risk management plan.

As noted in our risk management plan filings with the Commission, our hedging plan approved by our company's Risk Authorizing Committee describes the Company's strategies to reduce natural gas price volatility using a disciplined, nonspeculative approach for our customers.

Since the inception of our hedge program, the

Company has consistently applied the plan to our natural gas needs and for the benefit of our customers by limiting exposure to the volatile nature of natural gas price swings in the marketplace. And this concludes my summary.

Q Ms. Wehle, did you also prepare and submit the documents identified collectively as hearing Exhibit 29 in the Comprehensive Exhibit list?

A Yes, I did.

MR. BEASLEY: We tender Ms. Wehle for questions.

CHAIRMAN GRAHAM: Thank you.

Mr. Moyle.

MR. MOYLE: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. MOYLE:

Q As part of your responsibilities, at least before the job change, you keep up with the trends in fuels in terms of their directional movement, do you not?

A Yes.

Q Okay. So as we sit here today, can you comment on the directional movement of natural gas?

A I believe I can.

Q Okay. And would you agree that it's directionally headed down?

A It has been heading down, yes.

Q Okay. And there was the chart that was just referred to with the Gulf witness that showed the NYMEX prices. Did you happen to get a copy of that?

A I do not have a copy of that.

MR. MOYLE: If I could just hand her that exhibit.

CHAIRMAN GRAHAM: Sure.

MR. MOYLE: Do you have a copy, Jim?

THE WITNESS: Thank you.

MR. MOYLE: I referred her to the last page of Exhibit 68, which is the NYMEX chart.

BY MR. MOYLE:

Q And the question I want to ask you is, is that given where gas prices are today --

A Yes.

Q -- you know, Commissioner Skop previously talked about near record lows. Is Tampa Electric giving consideration to hedging a significant amount of natural gas currently for the near seeable future to lock it in at these low prices compared to the prices that were seen, say, in 2008?

A We are going to follow our risk management plan, which requires hedging of natural gas prices. And we've applied that consistently, and so we are going to continue to lock in those prices on a go-forward basis.

Q Does the risk management plan give flexibility to the people who are making hedge decisions to adjust to the extent that they see something or something occurs in the markets? You know, natural gas goes to a dollar, for example. Could you, could you alter your plan so that you go in, you know, at a dollar? And that even if you guess wrong and it goes to 50 cents, you know, the consumers are very well insulated from a situation that it might go to $10.

A Our plan does not have a price mechanism to change our strategy. And so therefore while we do have bands within which we operate within, depending on how much time is left before that particular month settles, we would continue to operate within those, within those bands and then appropriately hedge the commodity for those months going forward. We are not authorized to make changes.

And, you know, I would say we don't look at price as a mechanism to change those plans because I think at any given point in time you could then be second guessed as was that the right time to make that change?

In your example, why would you hedge everything at a dollar and then we would be second guessed as to why didn't you hedge it at 50 cents, if it were to fall that low?

And so therefore we feel like a much more disciplined approach over time will, will yield a, the result of mitigating price volatility for our customers.

Q If you could hedge at a dollar, you wouldn't hear a word from FIPUG, I promise you.

(Laughter.)

I had read an excerpt from an order, 080667, that talked about utilities gauging customers' tolerance for costs associated with hedging. You would agree that that's an important part of hedging, to, to keep the finger on the pulse with respect to the impact upon customers about the gains or losses; correct?

A I believe it's, it's our responsibility for all of our activities related to customers.

Q Okay. And at least with respect to FIPUG members, you're hearing a little bit of concern about some of the, some of the losses; correct?

A I've heard that today. Yes, sir.

Q Yes. And with respect to the 2009 results, was that the number you had changed in your testimony? Is that right?

A Yes, sir.

Q And it went from, what, 184 to 193?

A We had originally posted it as $184 million.

However, when the audit staff came in this past summer, we found an error in one of our months and corrected it, and it did go to 193 million.

Q And that's for 2009?

A Correct.

Q What -- describe 2010, if you would, in terms of customer gains or losses.

A Through September of this year we're in the neighborhood of about $53 million loss.

Q And then for 2011?

A For '11 -- and, again, remember, it's, it's completely unrealized at this point, so, you know, it changes every single day. We're in the neighborhood of about an $11 million loss.

Q And just so we're clear on that, that's if you basically mark to market today, you would be $11 million underwater with respect to cost?

A Correct. $11 million loss mark to market.

Q Okay. Now could you just briefly describe the generation mix that TECO has? Aren't you predominantly coal?

A We are predominantly coal. We've added some significant amount of natural gas in the 2003/2004 time frame. So we're at about a 55 to 60 percent coal, and then the balance pretty much is natural gas and less than

1 percent oil.

Q Okay. You don't hedge coal?

A We do not financially hedge coal. We physically hedge it.

Q Okay. And describe the difference, if you would, between physically and financially hedging?

A Sure. There is a very illiquid NYMEX contract, if you will, that basically is for a low sulfur type of, of product, low sulfur coal.

Our generation units burn high sulfur coal. And so, therefore, for us to enter into any kind of a NYMEX coal contract, it just wouldn't work because it isn't the type of fuel that we burn. So, therefore, what we do is we engage with our counter parties and fix the price on a go-forward basis for the term of the contract. Sometimes they're spot contracts, sometimes they're long, longer than that.

Q Could you also do that with natural gas in terms of fixing contracts with the parties just as you describe for coal?

A We could. You know, and we have on occasion done very, a little bit with actually natural gas producers. But for the most part we stick with financial over-the-counter products for natural gas.

Q There's an exhibit that I want to ask you a few questions about in a minute.

A Okay.

Q But a couple, a couple of points. With respect to reducing the risk of volatility, that's the objective of the hedge program; correct?

A That is correct.

Q Okay. There are, there are other ways that that can be accomplished, such as buying natural gas and storing it; correct?

A Yes. But you would eventually, you'd still be purchasing natural gas and you'd be paying a certain price for that and putting it in storage for later use. So I would submit to you that it's really not reducing price volatility.

Q How much capacity do y'all have to store natural gas?

A We just increased our storage capability to 1.25 million with our Bay Gas Storage facility outside of Mobile, Alabama.

Q Okay. And 1.25 million, just to give a little bit of relative amount of that, how many, how many days would that run your natural gas assets?

A Typically if you were to say our natural gas take can be anywhere upwards, you know, between 200,000 to 300,000 in the summertime, if you do the math there, that's, you know, literally five to seven days at different times during the year. And all that wouldn't necessarily be available to us anyway at any given time because there's requirements for rejection -- injection and then withdrawal.

Q So you think -- is a five- to seven-day amount --

A That would be the maximum storage capability.

Q Okay. You use Nucleus Risk Management System; is that right?

A We do.

Q Okay. And does that system help you make qualitative judgments about your hedging program, or is it just about, you know, keeping track of this contract was executed on this day? More sort of mechanical, if you will.

A It's more transaction based than qualitative based. But what it does is it allows us to maintain our system of controls by looking at authorized users and who has the ability to transact at different levels and at different tenors. And so it does provide a control mechanism from that perspective.

Q So with respect to the qualitative judgments, how are those made at TECO?

A As far as qualitative on our program?

Q Yes, ma'am.

A Well, the nucleus does help out because it lets us know how we're doing within our plan. And so, again, very transactional based and percentage based on volume.

Q Do you know, has the plan been materially changed since 2002?

A The only change that was made to the plan, and I believe it was around 2005, was an increase in the length of time which we can hedge within. So we increased it from an 18 months' viewpoint into the future to 24 months.

MR. MOYLE: Okay. Mr. Chair, if I could approach with an exhibit.

CHAIRMAN GRAHAM: Sure thing.

MR. MOYLE: And I've spoken with counsel for TECO. This is a confidential exhibit, so we need to treat it that way. And maybe, however, however the preference is, collect it at the end, but it is a confidential exhibit that I'm going to have some questions about.

CHAIRMAN GRAHAM: Okay. If I can get Staff to help you pass that out. We will number that as number 69.

(Exhibit 69 marked for identification.)

MS. HELTON: Mr. Chairman, I notice that it's not in a red folder, which is our typical practice. So does it have "Confidential" stamped in the front, Mr. Moyle, so we can at least --

MR. MOYLE: Yes.

MS. HELTON: Okay.

CHAIRMAN GRAHAM: And I take it the confidential stuff is highlighted?

MR. MOYLE: Yes, Mr. Chairman. The confidential information is highlighted.

CHAIRMAN GRAHAM: And can we get a short title?

MR. MOYLE: Excerpt of TECO Annual Risk Management Report.

CHAIRMAN GRAHAM: Thank you, sir.

MR. MOYLE: 69?

CHAIRMAN GRAHAM: Yes, sir.

BY MR. MOYLE:

Q Would you please identify this exhibit?

A This particular exhibit is page three of six of the Annual Risk Management Report that was filed on April 1st and corrected, as I mentioned earlier, on August 31st of this, of 2010.

Q Okay. And what was the correction that was made?

A It was to the actual amount hedged, I believe, to December of '09. I think there was a transposition error for that particular month that was trued up.

Q Okay. And I think in your opening you had talked about that the Company doesn't take speculative positions; is that right?

A That's correct.

Q So am I correct then that when hedging, you, you would not take on more natural gas than you had use for; correct?

A That's correct.

Q Okay. If you look at the November 2009 --

A Yes, sir.

Q -- number, and, again, I mean, you're treating this as confidential, so we're not going to talk numbers necessarily. But --

A Yes.

Q -- if I could ask you to reconcile that percent hedged with your policy of not taking speculative positions, that would be helpful.

A Yes. As we establish our bands with which we, within which we trade, what we do is we do it on a projected basis. And so, therefore, we do our best in order to project what our volumes are going to be. At times we fall short of that.

And so in that particular instance, that amount was over the, the amount that is in the policy to hedge;

however, it's explainable. This is -- and this is not a situation that hasn't happened in the, before in the past, before in the past. This was actually looked at during the audit when the Staff came down over the summer, and they felt comfortable with all of our answers to that.

They're -- it's mostly weather driven and unit outage driven. And if you actually look over into the hedged volume column, which is the fourth one from the left, you can see that our hedge volume is even quite a bit less than what was done for October and December. And so although our consumption was quite a bit less, if you, if you reconcile the two of those, it really explains the difference there.

Q Okay. The columns that you have where you have percent hedged, budget price and hedge price --

A Yes.

Q -- what is the, what is the budget price?

A That is what we actually put into the fuel budget or the fuel filing here.

Q So in terms of, in terms of looking at the budget price and the hedge price.

A Yes.

Q And then there's the settle price. That's what you actually paid for it; is that right?

A That's correct. What it actually settled for. And the delta between the hedge price and the settle price will, if you multiply that times your hedge volume, it'll give you your mark to market gain or loss.

Q Okay. I thought that the delta between the settle price and the budget price was somewhat remarkable, and I wanted to know if you would agree with that.

A I don't know what you mean by remarkable.

MR. MOYLE: Well, Mr. Beasley, I mean, it's not -- you don't want the numbers talked about.

THE WITNESS: There is --

MR. MOYLE: I mean, I think I may talk about an order of magnitude in terms of, of there being a pretty big difference between your budget price and your settle price. Does that work okay?

THE WITNESS: Yes. Sir, if I can address that. There, there is a difference there and it is rather large. However, you have to remember at the time the budget is developed, we're in the summertime. And if you go back and look at what prices we're trading at will probably dictate what our budget number would be there. And so it's, it's all a matter of when are those numbers developed?

BY MR. MOYLE:

Q Right. But to the extent that that budget price number is the number that you're putting forward for this Commission to set fuel factors on and, you know, your hedge price is considerably less and then your settle price is even more, even considerably less, you know, that, that to me looks like a pretty big overrecovery potential the way those numbers line up. Would you agree?

A I would agree, and that was the result was somewhat of an overrecovery between the hedge price and the budget price. But more goes into it than just the commodity itself. There are other things that flow into that, into the budget price as well, such as the use of the natural gas transportation costs.

Q With respect to your fuel recovery, does the Company have a preference whether overrecovery, under recovery? I mean, if you're going to be wrong, would you rather be wrong in asking for too much or --

A I think the, the Company would like to be right on the mark, although we have yet to do that.

Q And that's, that's I think where, where consumers would like you to be. But with respect to that question, is, are you able to answer that in terms of a preference?

A Over or under? Again, I think we'd like to be as close to zero as possible.

Q Okay. But based on these numbers then, it's a fair assumption that you were considerably over; correct?

A Yes, sir.

Q I had asked an earlier witness a question about the 2011 annual report, asking them to point to the numerical assessment of an acceptable level of price risk for natural gas found in the management plan. Could you do that for me? And you're familiar with the original hedging order; is that right?

A The 2002 hedging order?

Q Yes, ma'am.

A Yes.

Q And that was one of the components of that; correct?

A I would have to go back and look at -- I know there was a list of 14 or 15 different items.

Q Okay. Well, I'll represent to you that it was. If you want to double-check, I can show it to you.

A Okay.

Q But if you would just point to the numerical assessment of an acceptable level of price risk for natural gas.

A I believe that on page 4 of the risk management plan for 2011 there's some confidential data that's listed on the bottom of page 4 and continues on to the page, to the top of page 5.

Q Okay. Do you, do you set forth your limitations? Do you have a dollar limit as to how much the consumers might be exposed to as a result of hedging?

A No, we do not.

Q Okay. Do you think that might be something to look at in the future?

A Explain to me a little bit further about what you're getting at.

Q Well, in terms, in terms of the order of magnitude of the potential financial impacts, to have a provision that says, look, you know, you can hedge, but we don't want hedging losses coming forward in the amount of a billion dollars. So can you tailor your program in a way that, you know, through collars and swaps and all these fancy trading mechanisms, you're not, we're not going to be looking at more than a billion dollars in losses on an annual basis?

A I think that would be something that the Commission would have to approach each of the companies and have to look at the companies' individual fuel mix and, and programs in order to attempt that if, if there was a certain dollar threshold that they were looking to avoid.

Remember though that we do also have the 10 percent midcourse correction that can occur throughout the year, which would also true up prices if, if any of the companies were to get out of whack, if you will, on a plus or minus 10 percent basis or above.

MR. MOYLE: Okay. That's all the questions I have. Thank you.

CHAIRMAN GRAHAM: Thank you, sir.

Staff?

CROSS EXAMINATION

BY MS. BENNETT:

Q Thank you. Good morning or afternoon.

A Good afternoon.

Q Ms. Wehle, I'm -- Wehle; right?

A Wehle.

Q After four years I think I've got it right.

I'm Lisa Bennett with Commission Staff. I think on the desk before you is Staff's Exhibit Number 67, 67.

A Yes, ma'am.

Q Have you had an opportunity to review this document in the past?

A I have. Mostly the Tampa Electric portion of it.

Q And the Tampa Electric portion of that starts on page 79; is that correct?

A Yes.

Q And can you tell me what involvement TECO had with the preparation and presentation of this study?

A We were very involved with the gentleman from the Staff that came and visited with, with the Company and the different group, folks in my group, as well as the Risk Management Group answering questions, providing transaction data. A lot of the, of the background data came from the fuels management area to, to populate this particular report.

Q And were you also involved in several informal meetings regarding this?

A Yes, ma'am.

Q And did this audit end up in Order Number PSC-080667-PAA?

A Yes.

Q And I want to turn now to -- the Commission has determined as prudent the hedging transactions prior to July 31st, 2009; is that correct?

A That's correct.

Q For the results of hedging activities for the 12-month period ending July 31st, 2010, TECO enter into hedge positions at market prices; is that correct?

A That's correct.

Q For the same period were TECO hedging activities guided by its risk management plan?

A Yes, ma'am.

Q In the 2008 fuel clause proceeding, the Commission approved TECO's risk management plan for hedging transactions entered into during 2009; is that correct?

A Could you repeat the question?

Q Sure. In the 2008 fuel clause proceeding, Gulf -- I mean, sorry, Gulf did, but TECO is who I'm asking you about, presented its risk management plan for hedging transactions and that was approved.

A Correct.

Q And that was for 2009 hedging activities?

A Yes, ma'am.

Q Okay. Does TECO's risk management plan that governs the 2011 hedging transactions in your opinion comply with the guidelines established in Order 080667?

A Yes, it does.

Q Would you agree with me that the purpose of TECO's hedging activities is to reduce TECO's exposure to fuel price volatility?

A Yes, ma'am.

Q And based on this purpose, will there be times when TECO has hedging gains or savings and times when they have losses?

A Yes, it will.

MR. BEASLEY: I have no further questions.

CHAIRMAN GRAHAM: Okay. To the Commission board. Commissioner Skop.

COMMISSIONER SKOP: Thank you. I had asked Staff to locate some information that's not yet been forthcoming, so I would respectfully request if we could take a ten- or 15-minute break at this point to allow me to get the information I need, which is confidential information, I'd appreciate that, as the ability to ask questions that I have.

CHAIRMAN GRAHAM: If it's okay, I'd like to go to the rest of the board. And if it's not here at that time, we can take the recess.

COMMISSIONER SKOP: All right.

CHAIRMAN GRAHAM: Commissioner Brisé.

COMMISSIONER BRISÉ: Thank you, Mr. Chairman.

I just have one question. When we're looking at Exhibit 69, which is marked confidential, you mentioned that the difference between the budget price and the settle price is for transportation. I'm just curious as to what percentage would represent the transportation cost or price.

THE WITNESS: Is 69 the page 3 of 6?

COMMISSIONER BRISÉ: Yes. Page 3 of 6.

THE WITNESS: Okay. Actually I'd like to correct that statement. I don't think there's any transportation costs in, in these actual budgeted numbers in order to do a proper compare, apples-to- apples comparison.

So, but what my point to Mr. Moyle was is that there are transportation costs associated with natural gas that actually do flow through the clause as well besides just these numbers here on the commodity.

COMMISSIONER BRISÉ: Follow-up, Mr. Chair?

CHAIRMAN GRAHAM: Yes.

COMMISSIONER BRISÉ: You also represented that there are some other costs that are incurred as part of the budget price that, that aren't necessarily the commodity price found at the settle price. So if you could elaborate on that.

THE WITNESS: There are -- any other costs associated with getting the gas to your facility. Mr. Moyle also brought up the fact that we do maintain natural gas storage at a facility, and there are fees associated with that that would flow through the clause as well. So that's another type of, of cost that would actually be incurred.

COMMISSIONER BRISÉ: Follow-up?

CHAIRMAN GRAHAM: Yes, sir.

COMMISSIONER BRISÉ: Thank you. If you could quantify that for me, not, not in terms of the dollars, but just quantify within that difference that exists --

THE WITNESS: Uh-huh.

COMMISSIONER BRISÉ: -- how much of that difference in terms of percentage goes towards those costs versus what we see as the actual.

THE WITNESS: I don't have the storage costs associated readily. You know, we could file that as a late-filed exhibit, if you'd like.

However, on, on the transportation side, anywhere from, a rule of thumb, 76 cents to in the neighborhood of $1.50 depending on how much transportation is used in a given month and how much you actually have procured and which phases of gas transportation purchases have been made on the pipelines.

COMMISSIONER BRISÉ: Okay. Thank you.

THE WITNESS: Uh-huh.

CHAIRMAN GRAHAM: Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chair.

Good afternoon. A little bit ago Mr. Moyle asked you to discuss or distinguish the difference between physical hedging and financial hedging.

THE WITNESS: Yes.

COMMISSIONER EDGAR: Could you either give that answer again or elaborate on it a little more?

THE WITNESS: Sure. Sure. And specifically it relates to our coal purchases. We, we consider that physical hedging because we are actually taking delivery of the underlying product in that contract, as opposed to financial hedging where you're actually doing an over-the-counter trade or you're doing some kind of a derivative on an exchange.

And so under physical hedging, like I said earlier, that really relates to, to our coal purchases where we actually fix the price or as much of the price as we can with the actual counter party that we're buying the commodity from.

COMMISSIONER EDGAR: Thank you. And you've done it, but I'm going to ask this anyway.

THE WITNESS: Sure.

COMMISSIONER EDGAR: In your initial response to Mr. Moyle you used the term "fix the contract" or "fixing the contract," and I was wondering if you could expand on that term specifically?

THE WITNESS: Sure. For instance, if the, if a particular coal type is trading at, just a round number, $50 a ton, we would fix that price on a go-forward basis for, let's say, calendar 2011. So all the coal that we would buy from that counter party would be priced at $50 a ton taken at a certain delivery point. That's what I mean by that.

COMMISSIONER EDGAR: Thank you. Thank you.

THE WITNESS: Okay.

CHAIRMAN GRAHAM: I think we're still waiting for some more information for Staff to bring down here. So right now I have about 12 after 2:00. Let's give it about ten minutes. I'm sorry. Quarter after 2:00. Let's give it about ten minutes. Is that okay, Mr. Skop? So about 25 after we'll reconvene.

(Recess taken.)

All right. Let's get started again.

Commissioner Skop, you have the floor.

COMMISSIONER SKOP: Thank you.

Good afternoon, Ms. Wehle.

THE WITNESS: Good afternoon.

COMMISSIONER SKOP: I was actually hoping Staff would find a copy of the hedging plan and guidelines that showed the specific percentages that, within the plan that TECO submitted on how they would hedge their specific fuel requirements for various fuel commodities and for natural gas without giving away what the percentages were, which I don't remember but I could probably be real close in guessing. There's a certain percentage by each month of the year that TECO planned to hedge its natural gas requirements for. Is that generally correct?

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: And in relation to what's been marked for identification as Exhibit 69, which is a confidential document, Mr. Moyle asked you some questions regarding the November month, which, as the title, I mean, as the column is entitled percentage hedged. That threw me a little bit, so it caused me, during the break, since Staff did not have the data available, to create a spreadsheet to better understand how the numbers on those, on that page originated. And so I think I understand that the reason for that percentage hedged in November basically results from, from other data on that same row; is that correct?

THE WITNESS: That is correct.

COMMISSIONER SKOP: Okay. All right. But in the aggregate, and without getting into confidential information, TECO for natural gas in 2009 hedged somewhat less than its entire fuel requirement for natural gas; is that correct?

THE WITNESS: That is correct. And actually, sir, to further that, our total that we percentage hedged for the year was within our plan guidelines.

COMMISSIONER SKOP: Okay. And that's, that's what I was trying to ascertain, whether the month of November substantially departed from that, and I think I've convinced myself the answer is no. It's just the manner in which the data is presented here in this table makes things appear out of the norm and somewhat confusing. So I think I resolved that.

And the confidential number that shows the total percent hedged, I've reasonably convinced myself that that's in line looking at what the hedged amounts would be per month based on the hedge volume versus the total annual consumption. I think I ball parked it to get a comfort level with it in the absence of having the data.

The other two questions I had -- actually three questions -- is you mentioned that for 2010 to date the loss on the hedging program for natural gas is approximately $53 million; is that correct?

THE WITNESS: That's correct.

COMMISSIONER SKOP: Okay. And then for 2011, at this point in time it's approximately $11 million, but that could change given that, you know, we don't know what the gas price is going to be in 2011 yet; is that correct?

THE WITNESS: That's correct. That's just on realized losses at this point.

COMMISSIONER SKOP: Okay. And then on that table that's within Exhibit 69 that we've been discussing where it talks about budget price versus the settlement price versus the hedge price, am I correct to understand that the budget price is based on forward-looking fuel forecasts that TECO prepares when it submits its hedging plan or fuel forecast for the year.

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: Okay. And would it also be correct to understand that the hedge price is the actual price of the hedge that was placed in that specific month shown for 2009?

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: Okay. And the settlement price would be actually the closing price of gas either by the contract or the Henry Hub. Can you elaborate on that?

THE WITNESS: It's, it's the NYMEX contract. Yes, sir.

COMMISSIONER SKOP: Okay. All right. So the closing price of the NYMEX contract at a specific delivery point.

THE WITNESS: At the Henry Hub. Yes, sir.

COMMISSIONER SKOP: Okay. All right. Thank you.

All right. And then just one final question that I had, and it gets into a question I had previously for TECO, and I think Mr. Moyle tried to touch upon, I think, what I was trying to articulate.

In following the hedging guidelines and the hedging plans that have been submitted by each of the respective investor-owned utilities and approved by this Commission, those dictate, you know, the utility is going to do something by percentage in a given month spread across the year.

And I think that the concern I had, and I think the point Mr. Moyle was trying to get at, you know, following that prescriptively obviously provides regulatory certainty, which is important to the utilities and equally important to the Commission. So I understand that.

I think that the question I have, and the same would hold true for the other utilities, if the utilities saw something like a historical low in natural gas that would clearly provide a legitimate rationale for revising their hedging plan or seeking to depart for it for various specific reasons, i.e., a tremendous cost savings to the consumer by locking in natural gas. And I understand the point you made about you don't want to be second guessed if we hedge at a dollar and it drops to 50 cents, and that's a legitimate concern.

But is there any reason that TECO, and this applies to the other utilities, have not -- you know, if they see an opportunity, and I know we're not speculating, but we're at, you know, gas has fallen out, we're at a historical low, so we're at a floor, so there can't be much downside, but there could be a lot of upside. And that's where it starts costing consumers a lot more money if those -- you know, I heard a comment that you hedge on the way down. But, you know, where consumers incur a lot of additional cost is when prices start moving up dramatically.

So the question I have as a parting thought is, is has there been any consideration given, instead of prescriptively following the approved hedging plan, to coming in with opportunities that are not speculative but just sound judgment of trying to lock in prices and maybe depart from, you know, hedging X percent in this month and X percent in that month and a little more the next month throughout the year, and just saying, look, we see an opportunity and we want to be able to lock in all of our fuel requirements while gas is historically low? Has there been any discussion or thought, or I mean are the utilities just scared to propose that in the Commission?

Because I don't think the Commission would, you know, I don't want to speak for my colleagues, but I mean obviously the Commission looks favorably on trying to do the right things to save Florida ratepayers money.

And I think that, you know, we can get prescriptively caught up in hedging plans which were put in place to protect the utilities from armchair quarterbacking and second guessing and provide regulatory certainty, and I'm fine with that. But I also can't be agnostic to the fact that gas is at historical lows, and there may be some latitude there for utilities to propose something a little bit, you know, outside the scope of what the plan is instead of prescriptively following a plan. And I just wanted to get your perspective on that.

THE WITNESS: Commissioner, I, I've been a part of the hedging workshops and dockets since they actually started in 2002. And the one thing I think that all participants have gleaned from it is that there's just a lot of oversight related to hedging in general and what's the best way to do it and what's the right way to do it.

And I think the overall feeling, I'll just speak for TECO, the others might share this, is that we're very concerned about the Monday morning quarterbacking, especially since in light of the fact that we revisited this in 2008, we went through numerous meetings, informal, more formal, audits, reviews, and all we did was go back and say that the programs that we had in place were effective and so forth.

To say that we've never said, gee, wouldn't it be great if we just lock it in and we can kind of, you know, not worry about the rest of the year, I mean, we, there are, you know, water cooler discussions, if you will, about things like that.

But, again, we're, I think as a company we're very concerned about the fact that, you know, Commissioners may leave, you know, new people may come in and see it and, and provide a different perspective to it after it's all said and done. And what's the appropriate amount of time? Do you do it just for 2011? Do you look at it for longer than that?

I agree with you, it's, it's a very difficult decision to make. I think if the Commission approached the utilities and said, you know, we think it's ripe for us to look at a short window, we certainly would be open to that. However, I think given the fact that we've had so much scrutiny in this particular area, in fact, to the point where we feel like in years where there are mark to market gains we don't hear about it, but in years where there's mark to market losses, it's kind of drug out from the closet and revisited, we're just, we're skeptical, we're skittish. And so, therefore, I don't know that you're going to see it brought forth by one of the utilities, and that's just my honest opinion.

COMMISSIONER SKOP: And I appreciate your candor on that. Again, I've been through the, the hedging discussion that the Commission entertained in 2008 where we did put in some what I feel to be best practices to protect Florida ratepayers, but also to mitigate fuel price volatility that has been substantial, particularly in the natural gas markets, whether that be through market manipulation or things beyond control. But for some of our utilities, they get a lot of their generation from natural gas.

THE WITNESS: Yes.

COMMISSIONER SKOP: So gas swings have a big price impact on, on Florida ratepayers, including, you know, not only residential, but commercial.

But -- and I understand the armchair quarterbacking and the reluctance, you know, probably better than most. So I appreciate the position.

I think that I alluded to or tried to hint at this during last year's fuel proceeding. You know, I know that we can religiously and prescriptively follow the hedging plan that's in place so everyone is protected because, you know, hey, we did what the Commission approved, and I understand that. I'm just saying there are, I think, unique times such as now where natural gas is at a, you know, a low that we have not seen in quite some time to where thinking outside of the box instead of religiously or prescriptively following a hedging plan might have some merit, might have some benefit not only to the Company but to Florida ratepayers.

And, again, you know, I respect the utilities needing regulatory certainty and that's what the hedging plan provides, but I also equally appreciate innovative thinking and outside of the box thinking that saves Florida ratepayers money.

And, again, I would, you know, at least from my perspective, if the utilities have a good idea -- I'm only here for two months, I'm out the door. But it seems to me that if you've got the right idea and it's founded on, on trying to leverage something to the benefit of your ratepayers, then certainly I think it would be foolhardy of the Commission not to consider any proposal put forth that would not offer substantial benefit to the ratepayers that does not involve speculation.

But I, I've seen the -- and, as you mentioned, where in the good years where there's a savings, we don't hear a peep about it. And then when gas falls through the floor, gas falls through the roof, you know, all we hear is losses, losses, losses. And that becomes a concern because it's asymmetric to some degree because we're focused on one thing at one time instead of the long-term or the big picture. But the losses can be substantial when gas trends downward, as we've seen, and that is a concern.

But also you could look at it conversely, that could be an opportunity, instead of prescriptively following a rigid plan, to look into whether you could lock in natural gas at least for the, for the current year or, you know, some portion outward. Because as prices go up, then, you know, unhedged or over time as prices go up you don't maximize the savings. But I know you can't time the market and I'm not suggesting speculation, but I am looking at, you know, gas prices that are very, very, very, very, very low. And I know when gas prices were very, very, very high when I managed wind projects in California, I know what I did to lock in revenue based on, on the pricing I had in place.

But I'll leave that to you guys. I just wanted to get your perspective, and I appreciate your candor on that matter. Thank you.

THE WITNESS: Yes.

CHAIRMAN GRAHAM: Other Commissioners?

Redirect?

MR. BEASLEY: No to redirect, sir. I'd like to move the admission of Exhibit 29, and also note that the document marked Exhibit 69 is contained on a confidential basis within Exhibit 29. So it's in the record, if we could perhaps just have this Exhibit 69 recollected.

CHAIRMAN GRAHAM: Mr. Moyle.

MR. MOYLE: I think that's okay, as long as we identify it real clearly for the record. If you could just identify where within your Exhibit 28 it's found, because there's a lot of reference to 69 in the discussion.

MR. BEASLEY: Right. It's Exhibit 29, and I will be happy to show you where it is in the exhibit.

MR. MOYLE: Okay.

CHAIRMAN GRAHAM: Okay. So we're going to put Exhibit 29 in the record and we're not going to put 69. Is that correct?

MR. BEASLEY: That's what we would propose. Yes, sir.

MR. MOYLE: Can I get it on the record where it is in the exhibit? I mean, you can show me, but that's not going to be in the record. Or alternatively we can put 69 in. Whatever. You know, I don't have strong feelings one --

MR. BEASLEY: It's Page 3 of 6 of the Risk

Management Report which is identified as such in Exhibit 29, Risk Management Report.

CHAIRMAN GRAHAM: Is that sufficient?

MR. MOYLE: Yes, sir.

CHAIRMAN GRAHAM: Okay. So we are going to move Exhibit 29 into the record.

(Exhibit 29 admitted into the record.)

And we're not going to put 69 there. I take it Staff is going to collect 69 back up again?

MS. BENNETT: Staff is going to collect 69.

And Staff would also at this point in time move Exhibit Number 67 into the record. That's the hedging audit report that we've been discussing.

CHAIRMAN GRAHAM: Staff is moving 67 into the record. Okay.

(Exhibit 67 admitted into the record.)

MS. BENNETT: Unless there's objections to it.

CHAIRMAN GRAHAM: Are there any objections to moving 67 into the record? Okay. Sounds good.

Mr. Beasley.

MR. BEASLEY: That concludes our case.

CHAIRMAN GRAHAM: Do we have any other questions or things for this witness?

MS. BENNETT: No, Mr. Chairman.

CHAIRMAN GRAHAM: I believe you're excused.

Thank you so very much for spending your time with us.

(Transcript continues in sequence in Volume 3.)

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

I, LINDA BOLES, RPR, CRR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorneys or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 2nd day of November, 2010.

Linda Boles

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