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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 160001-EI

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

VOLUME 2

Pages 229 through 448

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING:
CHAIRMAN JULIE I. BROWN
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER ART GRAHAM
COMMISSIONER RONALD A. BRISÉ
COMMISSIONER JIMMY PATRONIS

DATE: Wednesday, November 2, 2016

TIME: Commenced at 9:54 a.m.
Concluded at 10:26 a.m.

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

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

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:	ID.	ADMTD.

No exhibits in this volume

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibits of
H. R. Ball
Docket No. 160001-EI
Date of Filing: March 2, 2016

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 (SES). 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, 2015 through December 31, 2015. 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 four schedules be marked as Exhibit No. _____(HRB-1).

Q. During the period January 2015 through December 2015, 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 $427,208,518 which is $803,066 or 0.19% below the projected amount of $428,011,583. Actual net power transaction energy was 11,980,374,254 kWh compared to the projected net energy of 12,010,627,000 kWh or 0.25% below projections. The resulting actual average cost of 3.5659 cents per kWh was 0.06% above the projected cost of 3.5636 cents per kWh. This information is from Schedule A-1, period-to-date, for the month of December 2015 included in Appendix 1 of Witness Boyett's exhibit. The lower total fuel and net power transaction expense is attributed to a lower quantity of energy (kWh) available, after economy and other power sales are deducted, combined with a lower per unit cost (cents per kWh) for available energy than projected for the period. The actual total cost of available energy was below projections by $1,409,321 or 0.29% and the total quantity of available energy was above projections by 2,295,828,418 kWh or 16.44%. The actual cost per kWh of available energy was 2.9594 cents per kWh which is 14.37% lower than the projected cost of 3.4561 cents per kWh. The lower cost per kWh for available energy is due primarily to the mix of available energy containing a higher percentage of purchased power. These energy purchases were primarily from lower cost gas fired generating units that Gulf has secured under Purchase Power Agreements (PPA's).

Q. During the period January 2015 through December 2015, how did Gulf Power Company's recoverable fuel cost of net generation compare with the projected expenses?

A. Gulf's recoverable fuel cost of system net generation was $269,670,468 or 6.31% below the projected amount of $287,828,569. Actual generation was 7,835,770,000 kWh compared to the projected generation of 8,027,402,000 kWh, or 2.39% below projections. The resulting actual average fuel cost of 3.4415 cents per kWh was 4.02% below the projected fuel cost of 3.5856 cents per kWh. The lower total fuel expense is attributed to the quantity of kWh generated being lower than projected for the period combined with a lower cost per unit for fuel. The actual quantity of fuel consumed was 70,436,124 MMBTU which is 0.11% below the projected quantity of 70,515,175 MMBTU. The percentage of energy generated from coal fired resources was 52.10%, which was 1.68% higher than the projected percentage of 51.24%. The weighted average fuel cost for natural gas was $2.72 cents per kWh, which is 16.82% below the projected cost of $3.27 cents per kWh. The weighted average fuel cost for coal, plus lighter fuel, was $4.10 cents per kWh, which is 5.40% higher than the projected cost of $3.89 cents per kWh. This information is found on Schedule A-3, period-to-date, for the month of December 2015 included in Appendix 1 of Witness Boyett'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 was $169,463,722 (line 17 of Schedule A-5, period-to-date, for December 2015) compared to the projected cost of $156,811,418 or 8.07% above the projected amount. The higher total coal cost was due to the actual quantity of coal purchased being 4.60% higher than projected combined with the weighted average price of coal purchased being $79.94 per ton which is 3.32% above the projected price of $77.37 per ton.

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

A. The total cost of coal burned was $163,312,141 (line 21 of Schedule A-5, period-to-date, for December 2015). This is 4.53% higher than the projection of $156,240,099. The higher total coal burn cost was due to the quantity of coal burned being 0.43% above projections combined with the actual weighted average coal burn cost being $82.59 per ton which is 4.08% above the projected burn cost of $79.35 per ton for the period.

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 $101,383,681 (line 34 of Schedule A-5, period-to-date, for December 2015). This is 20.09% below the projection of $126,873,289. The lower total gas cost was due to the actual weighted average gas burn cost being

$3.78 per MMBTU, which is 19.92% lower than the projected burn cost of $4.72 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 2015 complied with the Risk Management Plan filed on July 25, 2014.

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 is generally 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. As shown in Schedule 1 of my exhibit, total coal shipments for the period amounted to 2,772,383 tons. Gulf purchased 47% 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 typically needed 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 due either to economic or operational reasons. Gulf purchased 53% of its 2015 coal supply 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 shipments to Gulf's generating plants for the period as reported on the monthly FPSC 423 reports.

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 the price volatility of its 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 shipments for the period and the weighted average price of shipments under each purchase agreement in $/MMBTU. Because of the mix of longer-term contract coal purchase agreements and spot purchase agreements during the period, Gulf was able to take advantage of lower market pricing for spot coal. The variance between the estimated purchase price of coal and the actual price for the period was 3.32% above projected as reported on line 16 of Schedule A-5, period to date, for the month of December 2015.

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. 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 the market price on a percentage of these purchases 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 2015, Gulf's weighted average cost of natural gas purchases for generation was $3.74 per MMBTU. This was 20.76% lower than the projection of $4.72 per MMBTU (line 29 of Schedule A-5, period-to-date, for December 2015). 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 calculated volatility of Gulf's delivered cost of natural gas for the Smith 3 and Central Alabama PPA combined cycle generating units for the period is represented by a variance of 0.14 and standard deviation of 0.37. The calculation of the volatility of Gulf's hedged delivered cost of natural gas for the period yields a variance of 0.11 and standard deviation of 0.33. The lower variance and standard deviation for hedged cost of natural gas continues to demonstrate that hedging of natural gas prices reduces price volatility.

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

A. Gulf Power hedged 31,900,000 MMBTU of natural gas in 2015 using financial instruments. This represents 57% of Gulf's 56,042,912 MMBTU of actual gas burn for Smith Unit 3 plus the actual gas burn for the Central Alabama PPA combined cycle unit during the period. The total amount of natural gas burn by month for these units is reported on Schedule 4 of my exhibit.

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 swap contracts that fixed the price of gas to a certain price. These swaps settled against either a NYMEX Last Day price or Gas Daily price. Of the volume of gas hedged for the period, all was hedged using financial swap contracts.

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 2015 through December 2015?

A. No fees, commissions, or premiums were paid by Gulf on the financial hedge transactions during this period. Gulf's 2015 hedging program resulted in a net financial loss of $50,572,362 as shown on line 2 of Schedule A-1, period-to-date, for the month of December 2015 included in Appendix 1 of Witness Boyett'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 2015 through December 2015 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 ($53,982,546) or 1.11% below the projected amount of ($54,588,801). Total quantity of power sales were (4,279,206,164) kWh compared to Gulf's projected sales of (1,953,125,000) kWh, or 119.10% above projections. The resulting average fuel cost of power sold was 1.2615 cents per kWh or 54.86% below the projected amount of 2.7949 cents per kWh. This information is from Schedule A-1, period-to-date, for the month of December 2015 included in Appendix 1 of Witness Boyett'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 the lower than projected fuel reimbursement rate (cents per kWh) paid to Gulf for typical power sales. The more favorable position of Gulf's generating assets in system economic dispatch to serve load resulted in a greater quantity of energy sales.

Q. During the period January 2015 through December 2015, how did Gulf Power Company's recoverable fuel cost of purchased power compare to projected cost?

A. Gulf's recoverable fuel cost of purchased power for the period was $161,050,335 or 7.48% below the estimated amount of $174,080,000. Total kilowatt hours of purchased power were 8,423,810,418 kWh compared to the estimate of 5,936,350,000 kWh or 41.90% above projections. The resulting average fuel cost of purchased power was 1.9118 cents per kWh or 34.80% below the estimated amount of 2.9324 cents per kWh. This information is from Schedule A-1, period-to-date, for the month of December 2015 included in Appendix 1 of Witness Boyett's exhibit.

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

A. The lower total fuel cost of purchased power is attributed to Gulf purchasing energy at attractive prices to supplement its own generation to meet load demands. This includes energy supplied to Gulf through purchase power agreements. 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.

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). Gulf also purchases power when economically attractive under the terms of external purchase power agreements which have been reviewed and approved by the Commission.

Q. During the period January 2015 through December 2015, how did Gulf's actual net purchased power capacity cost compare with the net projected cost?

A. The actual total capacity payments for the January 2015 through December 2015 recovery period, as shown on line 4 of Schedule CCA-2 of Witness Boyett's Exhibit, was $88,425,147. Gulf's total re-projected net purchased power capacity cost for the same period was $88,526,101, as indicated on line 4 of Schedule CCE-1B of Witness Boyett's exhibit filed August 4, 2015. The difference between the actual net capacity cost and the projected net capacity cost for the recovery period is $100,954 or 0.11% less than the re-projected amount. This lower actual cost is due to Gulf having higher IIC capacity receipts than the re-projected amount for the 2015 recovery period.

Q. Was Gulf's actual 2015 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 Southern electric system 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.

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. 160001-EI
August 4, 2016

Q. Please state your name and business address.

A. My name is Herbert Russell 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 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 2016 through December 2016 and to summarize any noteworthy developments at Gulf in these areas. The current estimated/actual costs consist of actual expenses for the period January 2016 through June 2016 and projected fuel and net power transaction costs for July 2016 through December 2016. 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. I have no exhibits I am sponsoring as part of this testimony.

Q. During the period January 2016 through December 2016 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 $397,474,096 which is $33,577,037 or 7.79% below the original projected amount of $431,051,133. The lower total fuel and net power transaction expense for the period is attributed to lower fuel cost of generated power and purchased power. The resulting average per unit fuel cost is projected to be 3.3330 cents per kWh or 7.25% lower than the original projection of 3.5937 cents per kWh. The lower average per unit fuel and net power transactions cost (cents per kWh) is attributed to a lower per unit fuel cost of available energy for the period driven primarily by lower costs for purchased power, offset somewhat by a lower per unit fuel cost and gains on power sales. This current projection of fuel and net purchased power transaction cost is captured in the exhibit to Witness Boyett's testimony, Schedule E-1B-1, Line 14.

Q. During the period January 2016 through December 2016 how will Gulf Power Company's recoverable total fuel cost of generated power compare with the original projection of fuel cost?

A. Gulf's currently projected recoverable total fuel cost of generated power for the period is $267,852,395 which is $21,402,738 or 7.40% below the original projected amount of $289,255,133. Total generation is expected to be 6,859,524,000 kWh compared to the original projected generation of 8,228,439,000 kWh or 16.64% below original projections. The resulting average fuel cost is expected to be 3.9048 cents per kWh or 11.08% above the original projected amount of 3.5153 cents per kWh. This current projection of fuel cost of system net generation is captured in the exhibit to Witness Boyett's testimony, Schedule E-1B-1, Line 4.

Q. What are the reasons for the difference between Gulf's original projection of the total 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 a higher average per unit fuel cost (cents/kWh), the inclusion of the portion of Scherer Unit 3 for the period July – December 2016 which is serving Gulf's native load customers as fuel expense and financial hedging settlements.

Q How did the total projected fuel cost of system net generation compare to the actual cost for the first six months of 2016?

A. The total fuel cost of system net generation for the first six months of 2016 was $106,314,400 which is $42,565,800 or 28.59% lower than the projected cost of $148,880,200. On a fuel cost per kWh basis, the actual cost was 3.10 cents per kWh, which is 12.18% lower than the projected cost of 3.53 cents per kWh. This lower than projected cost of system generation on a cents per kWh basis is due to fuel cost in $/MMBtu being 13.92% lower than projected, offset somewhat by heat rate (Btu/kWh) of the generating units operating being 1.91% higher than projected. The lower price of fuel is a result of lower market prices for natural gas than projected for the period offset somewhat by higher coal costs and units operating at reduced efficiency levels during the period. This information is found on Schedule A-3 Period to Date of the June 2016 Monthly Fuel Filing.

Q. How did the total projected cost of coal burned compare to the actual cost for the first six months of 2016?

A. The total cost of coal burned (including boiler lighter) for the first six months of 2016 was $64,014,310 which is $19,969,627 or 23.78% lower than the projection of $83,983,937. The total coal fired generation was 1,421,816 MWH which is 36.47% lower than the projection of 2,237,900 MWH for the period. On a fuel cost per kWh basis, the actual cost was 4.50 cents per kWh which is 20.00% higher than the projected cost of 3.75 cents per kWh. The lower than projected total cost of coal burned (including boiler lighter) is due to total MMBtu of coal burn being 30.86% below the estimated burn for the period. The higher per kWh cost of coal fired generation is due to the weighted average heat rate (Btu/kWh) of the coal fired generating units that operated being 8.83% higher than projected combined with actual coal prices (including boiler lighter) being 10.00% higher than projected on a $/MMBtu basis. This information is found on Schedule A-3 Period to Date of the June 2016 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 and mix of contract shipments to Gulf's coal fired generating plants and firm transportation costs being spread over a lower quantity of coal shipped .

Q. How did the total projected cost of natural gas burned compare to the actual cost during the first six months of 2016?

A. The total cost of natural gas burned for generation for the first six months of 2016 was $41,891,733 which is $22,627,448 or 35.07% lower than Gulf's projection of $64,519,181. The total gas fired generation was 2,000,420 MWH which is 1.66% higher than the projection of 1,967,768 MWH for the period. The total cost of natural gas burned for generation is lower than forecast due to lower market prices for natural gas for the period. On a cost per unit basis, the actual cost of gas fired generation was 2.09 cents per kWh which is 36.28% lower than the projected cost of 3.28 cents per kWh. Actual natural gas prices were $2.86 per MMBtu or 40.04% lower than the projected cost of $4.77 per MMBtu. The gas fired unit heat rate (Btu/KWH) was 5.68% less efficient than projected. This information is found on Schedule A-3 Period to Date of the June 2016 Monthly Fuel Filing.

Q. For the period January 2016 through June 2016, what volume of natural gas was actually hedged using a fixed price contract or instrument?

A. Gulf Power financially hedged 17,130,000 MMBtu of natural gas for the period. This equates to 52.1% of the actual natural gas burn for Gulf's combined cycle generating units during the period of 32,852,195 MMBtu. This amount is the sum of the Plant Smith Unit 3 burn as reported on Schedule A-3 Period to Date of the June 2016 Monthly Fuel Filing and the Central Alabama PPA 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. The swaps settled against either a NYMEX Last Day price or Gas Daily price. The total amount of gas hedged for the period was hedged using financial swaps.

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 incurred. Gulf's gas hedging program generated a hedging settlement loss of $33,679,196 for the period January through June 2016. This information is found on Schedule A-1, Period to Date, line 2 of the June 2016 Monthly Fuel Filing.

Q. During the period January 2016 through December 2016 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 $(52,761,085) or 39.28% below the original projected amount of $(86,889,000). Total kilowatt hours of power sales is expected to be (3,932,170,427) kWh compared to the original projection of (3,370,149,000) kWh or 16.68% above projections. This current projection of fuel cost of power sold is captured in the exhibit to Witness Boyett's testimony, Schedule E-1B-1, Line 12.

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 lower total credit to fuel expense from power sales is attributed to a lower reimbursement rate (cents per kWh) for power sales offset somewhat by a higher quantity of power sales than originally projected. The currently projected price for the fuel cost and gains on power sales is 1.3418 cents/kWh which is 47.96% lower than the original projection of 2.5782 cents/kWh. The lower projected fuel reimbursement rate for power sales during the period are due to lower projected fuel costs associated with the units that are projected to set system pool interchange rates for power sales.

Q. How did the total projected fuel cost of power sold compare to the actual cost for the first six months of 2016?

A. The total fuel cost of power sold for the first six months of 2016 was $(31,978,085) which is $15,790,915 or 33.06% lower than the projection of $(47,769,000). The quantity of power sales for the period was 52.68% higher than projected. The actual cost was 1.0616 cents per kWh which is 56.15% below the projected cost of 2.4211 cents per kWh. This information is found on Schedule A-1, Period to Date, line 17 of the June 2016 Monthly Fuel Filing.

Q. During the period January 2016 through December 2016 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 $182,382,786 or 20.25% below the original projected amount of $228,685,000. The total amount of purchased power is expected to be 8,998,049,927 kWh compared to the original projection of 7,136,326,000 kWh or 26.09% above projections. The resulting average fuel cost of purchased power is expected to be 2.0269 cents per kWh or 36.75% below the original projected amount of 3.2045 cents per kWh. This current projection of fuel cost of purchased power is captured in the exhibit to Witness Boyett's testimony, Schedule E-1B-1, Line 7.

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 lower total fuel cost of purchased power is attributed to a lower projected price per kWh for purchased power due to lower natural gas market prices for the period.

Q. How did the total projected fuel cost of purchased power compare to the actual cost for the first six months of 2016?

A. The total fuel cost of purchased power for the first six months of 2016 was $83,330,786 which is $25,527,214 or 23.45% lower than our projection of $108,858,000. The lower than projected purchased power expense is due to the actual price of purchases being lower than projected offset somewhat by a greater quantity of purchases made. Purchased power quantity is 54.76% higher due to higher demand and the availability of lower cost energy purchases to meet this demand. On a fuel cost per kWh basis, the actual cost was 1.5915 cents per kWh which is 50.53% lower than the projected cost of 3.2174 cents per kWh. The majority of these purchases are from Gulf's PPAs which are a contracts associated with a gas fired generating unit and a wind power supply agreement. This information is found on Schedule A-1, Period to Date, line 12 of the June 2016 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, 2016 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. Were there any other significant developments in Gulf's purchased power program during the period?

A. No.

Q. During the period January 2016 through December 2016, 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 Boyett's testimony, Gulf's total current net capacity payment projection for the January 2016 through December 2016 recovery period is $87,336,137. Gulf's original projection for the period was $88,074,632 and is shown on Line 4 of Schedule CCE-1 filed September 1, 2015. The difference between these projections is $738,495 or 0.84% less than the original projection of net capacity payments. The variance is due to an increase in projected market capacity revenues combined with lower other capacity payments during the period.

Q. How did the total projected net capacity transactions cost compare to the actual cost for the first six months of 2016?

A. Actual net capacity costs during the first six months of 2016 were $44,294,625 (Lines 1 & 2 of Schedule CCE-1B in the exhibit of Witness Boyett's testimony) which is $192,766 higher than projected amount of $44,101,859 for the period (from Lines 1 & 2 of Schedule CCE-1 filed September 1, 2015).

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. 160001-EI
Date of Filing: September 1, 2016

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, 2017 through December 31, 2017. 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 four 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 April 6, 2016 and assigned Document Number DN 01828-16 (redacted) and 01826-16 (confidential information). This exhibit details Gulf Power's natural gas hedging transactions for August through December 2015 in compliance with Order No. PSC-08-0316-PAA-EI. The third exhibit (HRB-4) I am sponsoring as part of this testimony is Gulf Power Company's Hedging Information Report filed with the Commission Clerk on August 18, 2016 and assigned Document Number DN 06821-16 (redacted) and DN 06820-16 (confidential information). This exhibit details Gulf Power's natural gas hedging transactions for January through July 2016 in compliance with Order No. PSC-08-0316-PAA-EI. The fourth exhibit (HRB-5) I am sponsoring is Gulf Power Company's "Risk Management Plan for Fuel Procurement." This exhibit was filed with the Commission Clerk pursuant to a separate request for confidential classification on August 4, 2016 and assigned Document Number DN 05874-16 (redacted) and 05871-16 (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 four exhibits as just described be marked for identification as Exhibit Nos. _____ (HRB-2), _____ (HRB-3), _____ (HRB-4), and_____ (HRB-5) 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 2017 through December 2017 recovery period?

A. Gulf's projected total fuel and net power transaction cost for the period is $382,697,416. This projected amount is captured in the exhibit to Witness Boyett's testimony, Schedule E-1, line 19.

Q. How does the total projected fuel and net power transactions cost for the 2017 period compare to the updated projection of fuel cost for the same period in 2016?

A. The total updated cost of fuel and net power transactions for 2016, reflected on Schedule E-1B-1 line 14 of Witness Boyett's testimony filed in this docket on August 4, 2016, is projected to be $397,474,096. The projected total cost of fuel and net power transactions for the 2017 period reflects a decrease of $14,776,680 or 3.72% less than the same period in 2016. On a fuel cost per kWh basis, the 2016 projected cost is 3.3330 cents per kWh and the 2017 projected fuel cost is 3.1931 cents per kWh, a decrease of 0.1399 cents per kWh or 4.20%.

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

A. The projected total cost of fuel to meet system generated power needs in 2017 is $274,577,416. The projection of fuel cost of system generated power for 2017 is captured in the exhibit to Witness Boyett's testimony, Schedule E-1, line 5.

Q. How does the projected total fuel cost of generated power for the 2017 period compare to the updated projection of fuel cost for the same period in 2016?

A. The total updated cost of fuel to meet 2016 system generated power needs, reflected on Schedule E-1B-1, line 4 of Witness Boyett's testimony filed in this docket on August 4, 2016, is projected to be $267,852,395. The projected total cost of fuel to meet system net generation needs for the 2017 period reflects an increase of $6,725,021 or 2.51% greater than the same period in 2016. Total system net generation in 2017 is projected to be 9,352,830,000 kWh, which is 2,493,306,000 kWh or 36.35% greater than is currently projected for 2016. The higher projected total fuel expense is the result of a higher projected cost of coal, due primarily to the inclusion of Scherer Unit 3 coal cost for the period (which is serving Gulf's native load customers during the 2017 period), offset somewhat by a lower cost of natural gas (includes estimated hedging settlement costs). On a fuel cost per kWh basis, the 2016 projected cost is 3.9048 cents per kWh and the 2017 projected fuel cost is 2.9358 cents per kWh, a decrease of 0.9690 cents per kWh or 24.82%. The lower average per unit fuel cost is the result of both lower coal and gas fired generation cost (cents/kWh) for the 2017 period. Weighted average coal burned price including boiler lighter fuel for 2016 as reflected on Schedule E-3, line 32 of Witness Boyett’s testimony filed in this docket on August 4, 2016, is projected to be $3.43 per MMBtu. Weighted average coal burned price including boiler lighter fuel for 2017, as reflected on Schedule E-3, line 32 of the exhibit to Witness Boyett’s testimony, is projected to be $2.69 per MMBtu. This reflects a cost decrease of $0.74 per MMBtu or 21.57%. The cost decrease is due to inclusion of Scherer Unit 3, which utilizes a lower cost PRB coal supply, combined with coal supply contracts that have or will expire by the end of 2016 being replaced with lower priced coal supply agreements in 2017. Gulf’s coal supply agreements have firm price and quantity commitments with the contract coal suppliers and these contracts will cover a portion of Gulf’s 2017 projected coal burn needs. The remaining coal supply needs will be purchased on the spot market. Weighted average natural gas price for 2016, as reflected on Schedule E-3, line 33 of the exhibit to Witness Boyett’s testimony filed in this docket on August 4, 2016, is projected to be $3.38 per MMBtu. When the cost of natural gas hedging settlements (Schedule E-1B-1, line 1a) is included in the total delivered gas cost, the 2016 projected cost is $4.34 per MMBtu. Weighted average natural gas price for 2017, as reflected on Schedule E-3, line 33 of the exhibit to Witness Boyett’s testimony, is projected to be $3.95 per MMBtu. This is a decrease in price of $0.39 per MMBtu or 8.99%. As reflected on Schedule E-3, lines 40 and 41 of the exhibit to Witness Boyett’s testimony, the projected fuel cost of Gulf’s coal fired generation is 3.26 cents per kWh and the projected fuel cost of Gulf’s gas fired generation is 2.74 cents per kWh for the 2017 period. The generation mix in 2016, as reflected on Schedule E-3, lines 23 and 24 of the exhibit to Witness Boyett's testimony filed in this docket on August 4, 2016, is projected to be 46.91% coal and 52.71% gas. The generation mix in 2017, as reflected on Schedule E-3, lines 23 and 24 of the exhibit to Witness Boyett's testimony, is projected to be 56.13% coal and 43.61% gas. The projected cost of landfill gas to supply the Perdido Landfill Gas to Energy Facility in the 2016 projection period is $753,445 and the rate as reflected on Schedule E-3, line 42 of the exhibit to Witness Boyett's testimony filed in this docket on August 4, 2016, is projected to be 3.13 cents per kWh. The total projected cost for landfill gas in 2017 is $774,446 and the total facility generation is projected to be 24,719,000 kWh. The average rate, as reflected on Schedule E-3, line 42 of the exhibit to Witness Boyett's testimony, is projected to be 3.13 cents per kWh.

Q. Does the 2017 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-5) to this testimony.

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 April 6, 2016 and also on August 18, 2016 detailing its natural gas hedging transactions for August 2015 through July 2016. As noted earlier, I am sponsoring these reports as exhibits ______ (HRB-3 and HRB-4) to my testimony in this docket.

Q. Has Gulf adequately mitigated the price risk of natural gas and purchased power for 2016 through 2017?

A. Yes. Gulf has natural gas financial hedges in place for 2016 to adequately mitigate price risk. Gulf currently has natural gas hedges in place for 2017 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 by entering into financial hedge agreements whose total quantity exceed the projected natural gas burn for the period. 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 and the gas fired PPA units for which Gulf has tolling agreements. 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 are Gulf's projected recoverable fuel cost and gains on power sales for the 2017 period?

A. Gulf's projected recoverable fuel cost and gains on power sales is $105,784,000. This projected amount is captured in the exhibit to Witness Boyett's testimony, Schedule E-1, line 17.

Q. How does the total projected recoverable fuel cost and gains on power sales for the 2017 period compare to the projected recoverable fuel cost and gains on power sales for the same period in 2016?

A. The total updated recoverable fuel cost and gains on power sales in 2016, reflected on Schedule E-1B-1, line 12 of Witness Boyett's testimony filed in this docket on August 4, 2016, is projected to be $52,761,085. The projected recoverable fuel cost and gains on power sales in 2017 represents an increase of $53,022,915 or 100.50%. Total quantity of power sales in 2017 is projected to be 4,155,001,000 kWh, which is 222,830,573 kWh or 5.67% greater than currently projected for 2016. On a fuel cost per kWh basis, the 2016 projected cost is 1.3418 cents per kWh and the 2017 projected fuel cost is 2.5459 cents per kWh, which is an increase of 1.2041 cents per kWh or 89.74%. The 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 marginal fuel prices for units operating to meet incremental system loads combined with an increased quantity of energy sales for the period. The marginal fuel costs to operate Gulf generating units that run to meet power sales requirements are passed on to the purchasers of power and are reflected in the higher rate (cents/kWh) for the 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 $213,904,000. This projected amount is captured in the exhibit to Witness Boyett's testimony, Schedule E-1, line 12.

Q. How does the total projected purchased power cost for the 2017 period compare to the projected purchased power cost for the same period in 2016?

A. The total updated cost of purchased power to meet 2016 system needs, reflected on Schedule E-1B-1, line 7 of Witness Boyett's testimony filed in this docket on August 4, 2016, is projected to be $182,382,786. The projected cost of purchased power to meet system needs in 2017 is $31,521,214 or 17.28% higher than is currently projected for 2016. The total quantity of purchased power in 2017 is projected to be 6,787,282,000 kWh, which is 2,210,767,927 kWh or 24.57% lower than is currently projected for 2016. On a fuel cost per kWh basis, the 2016 projected cost is 2.0269 cents per kWh and the 2017 projected fuel cost is 3.1515 cents per kWh, which represents an increase of 1.1246 cents per kWh or 55.48%.

Q. What is Gulf's projected recoverable capacity payments for the 2017 cost recovery period?

A. The total recoverable capacity payments for the period are $84,407,518. This amount is captured in the exhibit to Witness Boyett's testimony, Schedule CCE-1, line 10. Schedule CCE-4 of Mr. Boyett's testimony shows the projected cost associated with Southern Intercompany Interchange and lists the long-term purchased power contracts that are included for capacity cost recovery, their associated capacity amounts in megawatts, and the resulting cost. Also included in Gulf's 2017 projection of capacity cost is revenue produced by a market-based agreements between the Southern electric system operating companies and South Carolina Electric & Gas and South Carolina PSA. The total capacity cost of $86,064,527 is shown on Schedule CCE-4, line 15 in the exhibit to Witness Boyett's testimony. The total capacity cost included on Schedule CCE-4 line 14 is the sum of 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 for the period?

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 $138,000 in its capacity cost recovery projection. This amount is captured in the exhibit to Witness Boyett's testimony, Schedule CCE-1, line 3.

Q. How do the total projected net jurisdictional capacity payments for the 2017 period compare to the current estimated net jurisdictional capacity payments for the same period in 2016?

A. Gulf's 2017 Projected Jurisdictional Capacity Payments, found in the exhibit to Witness Boyett's testimony, Schedule CCE-1, line 6, are $83,530,252. This amount is $1,248,212 or 1.47% less than the current estimate of $84,778,464 (Schedule CCE-1B, line 6) for 2016 that was filed in Mr. Boyett's actual/estimated true-up testimony in this docket on August 4, 2016. The projected capacity payment decrease is the result of a decrease in Gulf's estimated PPA related payments for the period.

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

A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
C. Shane Boyett
Docket No. 160001-EI
Date of Filing: March 2, 2016

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

A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520. I am the Supervisor of Regulatory and Cost Recovery at Gulf Power Company.

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

A. I graduated from the University of Florida in Gainesville, Florida in 2001 with a Bachelor of Science Degree in Business Administration. I also hold a Masters in Business Administration from the University of West Florida in Pensacola, Florida. I joined Gulf Power in 2002 as a Forecasting Specialist where I worked for five years until I took a position in the Regulatory and Cost Recovery area in 2007 as a Regulatory Analyst. After working in the Regulatory and Cost Recovery department for seven years, I transferred to Gulf Power's Financial Planning department as a Financial Analyst where I worked until being promoted to my current position of Supervisor of Regulatory and Cost Recovery. My responsibilities include supervision of: tariff administration, calculation of cost recovery factors, and the regulatory filing function of the Regulatory and Cost Recovery department.

Q. What is the purpose of your testimony?
A. The purpose of my testimony is to present the actual true-up amounts for the period January 2015 through December 2015 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 2016 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 2015 through December 2015.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes. My exhibit consists of 1 schedule that relates to the fuel and purchased power cost recovery actual true-up, 4 schedules that relate to the capacity cost recovery actual true-up, and 1 appendix that includes Schedules A-1 through A-9 and A-12 for the period January 2015 through December 2015, previously filed monthly with this Commission. Each of these documents was prepared under my direction, supervision, or review.

Counsel: We ask that Mr. Boyett's exhibit consisting of 5 schedules and 1 appendix be marked as Exhibit No. _____ (CSB-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 2015 through December 2015. In addition, Fuel Cost Recovery Schedules A-1 through A-9 for January 2015 through December 2015 are incorporated herein in Appendix 1.

Q. What is the actual fuel and purchased power cost true-up amount related to the period of January 2015 through December 2015 to be refunded or collected through the fuel cost recovery factors in the period January 2017 through December 2017?

A. A net amount to be collected of $1,324,066 was calculated as shown on Schedule 1 of my exhibit.

Q. How was this amount calculated?

A. The $1,324,066 was calculated by taking the difference in the estimated and actual over/under-recovery amounts for the period January 2015 through December 2015. The estimated over-recovery was $11,285,334 as shown on Schedule E-1B, Line 6 + 7 + 8 filed August 4, 2015. The actual over-recovery was $9,961,267 which is the sum of the Period-to-Date amounts on lines 7, 8, and 12 shown on the December 2015 Schedule A-2, page 2 of 3, included in Appendix 1. Additional details supporting the approved estimated true-up amount are included on Schedules E1-A and E1-B filed August 4, 2015.

Q. Has the benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for actual 2015 gains?

A. Yes, the three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2012 through 2014 is calculated as follows:

Year	Actual Gain
2013	194,730
2014	1,319,633
2015	674,392
Three-Year Average	$ 729,585

Q. What is the actual threshold for 2016?

A. The actual threshold for 2016 is $729,585.

Q. Is Gulf seeking to recover any gains or losses from hedging settlements for the period of January 2015 through December 2015?

A. Yes. On line 2 of Schedule A-1, Period-to-Date, for December 2015 included in Appendix 1, Gulf has recorded a net loss of $50,572,362 related to hedging activities in 2015. Mr. Ball addresses the details of those hedging activities in his testimony.

Q. Mr. Boyett, 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 2015 through December 2015. In addition, Capacity Cost Recovery Schedule A-12 for the months of January 2015 through December 2015 is included in Appendix 1.

Q. What is the actual purchased power capacity cost true-up amount related to the period of January 2015 through December 2015 to be refunded or collected in the period January 2017 through December 2017?

A. An amount to be collected of $965,767 was calculated as shown on Schedule CCA-1 of my exhibit.

Q. How was this amount calculated?

A. The $965,767 was calculated by taking the difference in the estimated January 2015 through December 2015 over-recovery of $910,906 and the actual under-recovery of $54,861, which is the sum of lines 10, 11, and 14 under the total column of Schedule CCA-2. The estimated true-up amount for this period was approved in FPSC Order No. PSC-15-0586-FOF-EI dated December 23, 2015. Additional details supporting the approved estimated true-up amount are included on Schedules CCE-1A and CCE-1B filed August 4, 2015.

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

A. Schedule CCA-2 shows the calculation of the actual under-recovery of purchased power capacity costs for the period January 2015 through

December 2015. Schedule CCA-3 of my exhibit is the calculation of the interest provision on the under-recovery for the period January 2015 through December 2015.

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. Boyett, does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
C. Shane Boyett
Docket No. 160001-EI
Date of Filing: August 4, 2016

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

A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520. I am the Supervisor of Regulatory and Cost Recovery at Gulf Power Company.

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

A. I graduated from the University of Florida in Gainesville, Florida in 2001 with a Bachelor of Science degree in Business Administration. I also hold a Master of Business Administration from the University of West Florida in Pensacola, Florida. I joined Gulf Power in 2002 as a Forecasting Specialist where I worked for five years until I took a position in the Regulatory and Cost Recovery area in 2007 as a Regulatory Analyst. After working in the Regulatory and Cost Recovery department for seven years, I transferred to Gulf Power's Financial Planning department as a Financial Analyst where I worked until being promoted to my current position of Supervisor of Regulatory and Cost Recovery. My responsibilities include supervision of: tariff administration, calculation of cost recovery factors, and the regulatory filing function of the Regulatory and Cost Recovery 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. Boyett's Exhibit consisting of fourteen schedules be marked as Exhibit No. ____ (CSB-2).

Q. Are you familiar with the Fuel and Purchased Power (Energy) estimated true-up calculations for the period of January 2016 through December 2016 and the Purchased Power Capacity Cost estimated true-up calculations for the period of January 2016 through December 2016 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. The fuel and purchased power energy true-up calculations reflect Plant Scherer Unit 3 as rededicated to serve native load customers as the interim long-term sales agreements expire.

Q. Mr. Boyett, what has Gulf calculated as the fuel cost recovery true-up to be applied in the period January 2017 through December 2017?

A. The fuel cost recovery true-up for this period is a decrease of 0.2364 ¢/kWh. As shown on Schedule E-1A, this includes an estimated over-recovery for the January through December 2016 period of $27,383,731. It also includes a final under-recovery for the January through December 2015 period of $1,324,066 (see Schedule 1 of Exhibit CSB-1 in this docket filed on March 2, 2016). The resulting total over-recovery of $26,059,665 will be addressed in Gulf's proposed 2017 fuel cost recovery factors.

Q. Have you made an adjustment to address the audit staff's finding in their report dated April 28, 2016?

A. Yes. An adjustment to the over-recovery balance in the amount of ($75,803.69) was made in March 2016. As a result, the three-year rolling average gain on economy sales for 2015 has been revised. The revised calculation is shown below.

	Year	Actual Gain
	2013	194,730
	2014	1,319,633
	2015	596,791
Revised Three-Year Average		$ 703,718

Q. What is the revised actual threshold for 2016?

A. The revised actual threshold for 2016 is $703,718

Q. Have you included the impact to customers related to Gulf's request to rededicate Gulf's ownership interest in Scherer Unit 3 to native load customers as the interim long-term sales agreements expire?

A. Yes. The inclusion of Scherer Unit 3 is reflected in the estimates provided in my exhibit for July through December. In addition, I am reflecting an adjustment of ($866,563.19) to the over-recovery balance in December 2016 to recognize the January through June impact. If fuel costs for Scherer Unit 3 is not included for this period, the resulting estimated over-recovery true-up amount for the January through December 2016 period would be $29,298,004.

Q. Mr. Boyett, 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 2017 through December 2017 period.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2017 through December 2017?

A. The true-up for this period is an increase of 0.0074 ¢/kWh as shown on Schedule CCE-1A. This includes an estimated over-recovery of $149,231 for January 2016 through December 2016. It also includes a final under-recovery of $965,767 for the period of January 2015 through December 2015 (see Schedule CCA-1 of Exhibit CSB-1 in this docket filed March 2, 2016). The resulting total under-recovery of $816,536 will be addressed in Gulf's proposed 2017 purchased power capacity cost recovery factors.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
C. Shane Boyett
Docket No. 160001-EI
Date of Filing: September 1, 2016

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

A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Regulatory and Cost Recovery at Gulf Power Company.

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

A. I graduated from the University of Florida in Gainesville, Florida in 2001 with a Bachelor of Science degree in Business Administration. I also hold a Master of Business Administration from the University of West Florida in Pensacola, Florida. I joined Gulf Power in 2002 as a Forecasting Specialist where I worked for five years until I took a position in the Regulatory and Cost Recovery area in 2007 as a Regulatory Analyst. After working in the Regulatory and Cost Recovery department for seven years, I transferred to Gulf Power's Financial Planning department as a Financial Analyst where I worked until being promoted to my current position of Supervisor of Regulatory and Cost Recovery. My responsibilities include supervision of: tariff administration, calculation of cost recovery factors, and the regulatory filing function of the Regulatory and Cost Recovery department.

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 2017 through December 2017. I will also discuss the calculation of the purchased power capacity cost recovery factors for the period January 2017 through December 2017.

Q. Have you prepared any exhibits that contain information to which you will refer in your testimony?
A. Yes. I have one exhibit consisting of 15 schedules, each of which was prepared under my direction, supervision, or review.

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

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. Mr. Boyett, what is the levelized projected fuel factor for the period January 2017 through December 2017?
A. Gulf has proposed a levelized fuel factor of 3.139¢/kWh. This factor is based on projected fuel and purchased power energy expenses for January 2017 through December 2017 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 2016 is 0.511¢/kWh less or 14 percent lower than the levelized fuel factor in place January through December 2016.

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 2017 through December 2017.

A. As shown on Schedule E-1A of my exhibit, the total true-up amount of $26,059,665 includes an estimated over-recovery for the January through December 2016 period of $27,383,731 plus a final under-recovery for the period January through December 2015 of $1,324,066. The estimated over-recovery for the January through December 2016 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 2015 through December 2015?

A. The GPIF result shown on Line 31 of Schedule E-1 is a decrease of 0.0004¢/kWh to the levelized fuel factor, thereby penalizing Gulf $45,708.

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. Boyett, 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. Boyett, 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 3.163¢/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. Boyett, 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 2017 through December 2017. 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 2016 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 2016 is 3.678¢/kWh compared with the proposed factor of 3.163¢/kWh. For a residential customer who is billed for 1,000 kWh in January 2017, the fuel portion of the bill would decrease from $36.78 to $31.63.

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 2017 through December 2018.

Q. Has Gulf recalculated the monthly bill credit for participants of its Community Solar Pilot Program for the period January through December 2017 as required by Order No. PSC-16-0119-TRF-EG issued March 21, 2016, in Docket No. 150248-EG?

A. Yes. The monthly bill credit amount of $1.80 for the period January through December 2017 was calculated using the 2017 projected solar-weighted average annual avoided energy cost of 2.9 cents per kWh.

Q. What amount have you calculated to be the appropriate benchmark level for calendar year 2017 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 $802,125 has been calculated for 2016 as follows:

2014 actual gains	1,319,633
2015 actual gains	596,791
2016 estimated gains	489,951
Three-Year Average	$ 802,125

This amount represents the minimum projected threshold for 2017 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 2017.

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 CSB-3 relate to the calculation of the PPCC recovery factors for the period January 2017 through December 2017.

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 2017 through December 2017, is $85,926,527. The jurisdictional amount is $83,530,252. 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 approved by the Commission in Order No. PSC-12-0179-FOF-EI issued April 3, 2012, in Docket No. 110138-EI. For purposes of the PPCC Recovery Clause, Gulf has allocated the net purchased power capacity costs by rate class within the retail jurisdiction based on the 12-MCP and 1/13th energy allocator. This allocation is consistent with the treatment accorded to production plant in the cost of service study approved by the Commission in Order No. PSC-12-0179-FOF-EI issued April 3, 2012, in Docket No. 110138-EI.

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

A. The demand allocation factors used in the PPCC Recovery Clause have been calculated using the 2015 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C. The energy allocation factors were calculated based on projected kWh sales for the period adjusted for losses. 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.

Gulf has calculated the PPCC factor for the LP/LPT rate classes based on kilowatt (kW) rather than kilowatt hour (kWh) in accordance with Order No. PSC-13-0670-S-EI issued December 9, 2013 in Docket No. 130140-EI. The total revenue requirement assigned to rate class LP/LPT shown in column E is then divided by the sum of the projected billing demands (kW) for the twelve-month period to calculate the PPCC recovery factor. This factor would be applied to each LP/LPT customer's billing demand (kW) to calculate the amount to be billed each month.

For all other rate classes, 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 is billed for 1,000 kWh will be $8.88.

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 2017 and continuing through the last billing cycle of December 2017.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
C. L. Nicholson
Docket No. 160001-EI
Date of Filing: March 16, 2016

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

A. My name is Cody L. Nicholson. 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 Auburn University in 1998. I joined Southern Company with Alabama Power in 1996 as a summer intern. Upon graduation in 1998, I joined Southern Company Services (SCS), a subsidiary of Southern Company. During my time at SCS, I worked in Farley Project and in Generating Plant Performance (GPP), where I progressed through various engineering positions with increasing responsibilities. My primary responsibility in Farley Project was to coordinate design changes to Plant Farley. My primary responsibility in GPP was to conduct heat rate tests and performance tests on plant equipment. I joined Southern Nuclear Operating Company (SNC) in 2011. At SNC, my primary responsibility was to coordinate responses to requests from the U. S. Nuclear Regulatory Commission for various projects. I joined SCS in 2014 as a Performance and Reliability Engineer, where my primary responsibility was to report key performance indicators on a monthly basis. I joined Gulf Power in 2015 in my current job position as Power Generation Specialist, Senior as previously mentioned in my testimony. 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, 2015, through December 31, 2015.

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. Nicholson's Exhibit consisting of five schedules be marked as Exhibit No. _______ (CLN-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 13 through 23 of

Schedule 5 of my exhibit incorporate these changes. The data contained in these tables is the data upon which the GPIF calculations were made.

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

A. Actual equivalent availability and adjusted actual equivalent availability figures for each of Gulf's GPIF units are shown on page 12 of Schedule 5. Pages 4 through 8 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-14-0701-FOF-EI is on page 9 of Schedule 2. The results are: Crist 6, +4.00 points; Crist 7, +4.55 points; Daniel 1, +10.00 points; Daniel 2, +10.00 points; and Smith 3, +5.71 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 6 of Schedule 3.

As was done for the prior GPIF periods, and as indicated on pages 7 through 11 of Schedule 3, the target equations were used to adjust actual results to the target basis. These equations, submitted in August 2014, are shown on page 13 of Schedule 3. As calculated on page 14 of Schedule 3, the adjusted actual average net operating heat rates correspond to the following GPIF unit heat rate points: Crist 6, -0.20 points; Crist 7, +7.58 points; Daniel 1, -3.90 points; Daniel 2, -10.00 points, and Smith 3, 0.00 points.

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 -0.13 as indicated on page 2 of Schedule 4. This calculated to a penalty in the amount of $45,708.

Q. Please summarize your testimony.

A. In view of the adjusted actual equivalent availabilities, as shown on page 9 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 14 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a penalty in the amount of $45,708 as provided for by the GPIF plan.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
C. L. Nicholson
Docket No. 160001-EI
Date of Filing: September 1, 2016

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

A. My name is Cody L. Nicholson. 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 Auburn University in 1998. I joined Southern Company with Alabama Power in 1996 as a summer intern. Upon graduation in 1998, I joined Southern Company Services (SCS), a subsidiary of Southern Company. During my time at SCS, I worked in the Farley Project department as well as Generating Plant Performance (GPP), where I progressed through various engineering positions with increasing responsibilities. My primary responsibility in Farley Project was to coordinate design changes to Plant Farley. My primary responsibility in GPP was to conduct heat rate tests and performance tests on plant equipment. I joined Southern Nuclear Operating Company (SNC) in 2011. At SNC, my primary responsibility was to coordinate responses to requests from the U. S. Nuclear Regulatory Commission for various projects. I joined SCS in 2014 as a

Performance and Reliability Engineer, where my primary responsibility was to report key performance indicators on a monthly basis. I joined Gulf Power in 2015 in my current job position as Power Generation Specialist, Senior as previously mentioned in my testimony. In this position, I am responsible for preparing all Generating Performance Incentive Factor (GPIF) filings as well as other generating plant reliability and heat rate performance reporting for Gulf Power Company.

Q. What is the purpose of your testimony in this proceeding?
A. The purpose of my testimony is to present GPIF targets for Gulf Power Company for the period of January 1, 2017 through December 31, 2017.

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

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

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

Q. Which units does Gulf propose to include under the GPIF for the subject period?

A. We propose that Crist Unit 7, Daniel Units 1 and 2, Smith Unit 3, and Scherer Unit 3 be included as the Company's GPIF units. The projected net generation from these units is approximately 89% of Gulf's projected net generation for 2017.

Q. For these units, what are the target heat rates Gulf proposes to use in the GPIF for these units for the performance period January 1, 2017 through December 31, 2017?

A. I would like to refer you to page 26 of Schedule 1 of my exhibit where these targets are listed.

Q. How were these proposed target heat rates determined?

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

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

A. Page 2 of Schedule 1 of my exhibit shows the target average net operating heat rate equations for the proposed GPIF units and pages 4 through 23 of Schedule 1 contain the weekly historical data used for the statistical development of these equations. Pages 24 and 25 of Schedule 1 present the calculations that provide the unit target heat rates from the target equations.

Q. Were the maximum and minimum attainable heat rates for each proposed GPIF unit indicated on page 26 of Schedule 1 of your exhibit calculated according to the appropriate GPIF Implementation Manual procedures?

A. Yes.

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

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

Q. How were the target equivalent availabilities determined?

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

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

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

Q. Mr. Nicholson, has Gulf completed the GPIF minimum filing requirements data package?
A. Yes, we have completed the minimum filing requirements data package. Schedule 3 of my exhibit contains this information.

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

1. Crist Unit 7, Daniel Units 1 and 2, Smith Unit 3, and Scherer Unit 3 for inclusion under the GPIF for the period of January 1, 2017 through December 31, 2017.
2. The target, maximum attainable, and minimum attainable average net operating heat rates, as proposed by the Company and as shown on page 26 of Schedule 1 and also on page 5 of Schedule 3 of my exhibit.
3. The target, maximum attainable, and minimum attainable equivalent availabilities, as proposed by the Company and as shown on page 4 of Schedule 2 and also on page 5 of Schedule 3 of my exhibit.
4. The weekly average net operating heat rate least squares regression equations, shown on page 2 of Schedule 1 and also on pages 17 through 26 of Schedule 3 of my exhibit, for use in adjusting the annual actual unit heat rates to target conditions.

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

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

A. My name is Penelope A. Rusk. 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, Rates in the Regulatory Affairs Department.

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

A. I hold a Bachelor of Arts degree in Economics from the University of New Orleans and a Master of Arts degree in Economics from the University of South Florida. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, where I have assumed positions of increasing responsibility during my 19 years of electric utility experience, including load forecasting, managing cost recovery clauses, project management, and rate setting activities for wholesale and retail rate cases. My duties include managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and approved environmental projects.

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 2015 through December 2015 for the Fuel and Purchased Power Cost Recovery Clause (“Fuel Clause”), the Capacity Cost Recovery Clause (“Capacity Clause”), and the wholesale incentive benchmark for January 2016 through December 2016.

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. PAR-1, consisting of five documents which are described later in my testimony, was prepared under my direction and supervision.

Capacity Cost Recovery Clause

Q. What is the final true-up amount for the Capacity Clause for the period January 2015 through December 2015?

A. The final true-up amount for the Capacity Clause for the period January 2015 through December 2015 is an under–recovery of $2,449,694.

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 2015 Through December 2015", provides the calculation for the final under–recovery of $2,449,694. The actual capacity cost under-recovery, including interest, was $245,925 for the period January 2015 through December 2015 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the $2,203,769 actual/estimated over-recovery approved in Order No. PSC-15-0586-FOF-EI issued December 23, 2015 in Docket No. 150001-EI, results in a final under-recovery of $2,449,694 for the period, as identified in Document No. 1, page 4 of 4. This amount will be applied in the calculation of the capacity cost recovery factors for the period January 2017 through December 2017.

Q. What is the estimated effect of this $2,449,694 under-recovery for the January 2015 through December 2015 period on residential bills during January 2017 through December 2017?

A. The $2,449,694 under-recovery will increase a 1,000 kWh residential bill by approximately $0.15.

Fuel and Purchased Power Cost Recovery Clause

Q. What is the final true-up amount for the Fuel Clause for the period January 2015 through December 2015?

A. The final Fuel Clause true-up for the period January 2015 through December 2015 is an over-recovery of $18,058,299. The actual fuel cost over-recovery, including interest, was $45,648,849 for the period January 2015 through December 2015. This $45,648,849 amount, less the $27,590,550 actual/estimated over-recovery amount approved in Order No. PSC-15-0586-FOF-EI, issued December 23, 2015 in Docket No. 150001-EI, results in a net over-recovery amount for the period of $18,058,299.

Q. What is the estimated effect of the $18,058,299 over-recovery for the January 2015 through December 2015 period on residential bills during January 2017 through December 2017?

A. The $18,058,299 over-recovery will decrease a 1,000 kWh residential bill by approximately $0.96.

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 2015 Through December 2015". It shows the calculation of the final fuel over-recovery of $18,058,299.

Line 1 shows the total company fuel costs of

$696,924,863 for the period January 2015 through December 2015. The jurisdictional amount of total fuel costs is $696,924,863, 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 $48,541,935 over-recovered fuel costs for the period, interest, true-up collected and the prior period true-up shown on lines 5 through 8 respectively, constitute the actual over-recovery of $45,648,849 shown on line 9. The $45,648,849 actual amount less the $27,590,550 actual/estimated over-recovery amount shown on line 10, results in a final $18,058,299 over-recovery for the period January 2015 through December 2015, as shown on line 11.

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

A. Document No. 3 is entitled "Tampa Electric Company Calculation of True-up Amount Actual *vs.* Original Estimates for the Period January 2015 Through December 2015." It shows the calculation of the actual over-recovery compared to the estimate for the same period.

Q. What was the total fuel and net power transaction cost variance for the period January 2015 through December 2015?

A. As shown on line A7 of Document No. 3, the fuel and net power transaction cost is $34,904,264 less than the amount originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2015 through December 2015?

A. As shown on line C3 of Document No. 3, the company collected $15,481,996, or 2.1 percent greater jurisdictional fuel revenues than originally estimated.

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

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

Q. Please describe Document No. 5 of your exhibit.

A. Document No. 5 provides the capital costs and fuel savings for the Polk Unit 1 and the Big Bend Units 1-4 ignition conversion projects for the period January 2015 through December 2015. This document also contains the capital structure components and cost rates relied upon to calculate the revenue requirements rate of return on capital projects recovered through the fuel clause.

The Polk Unit 1 ignition conversion project capital costs, including depreciation and return, for the period January 2015 through December 2015 are less than the project’s fuel savings. This is shown on Document No. 5, page 1, line 33. Therefore, the Polk Unit 1 ignition conversion project capital costs should be recovered through the fuel clause in accordance with FPSC Order No. PSC-12-0498-PAA-EI, issued in Docket No. 120153-EI on September 27, 2012.

The Big Bend Units 1-4 ignition conversion project capital costs, including depreciation and return, for the period are less than the fuel savings resulting from the project, as shown on Document No. 5, page 2, line 33. Therefore, the Big Bend Units 1-4 ignition conversion project capital costs should be recovered through the fuel clause in accordance with FPSC Order No. PSC-14-0309-PAA-EI, issued in Docket No. 140032-EI on June 12, 2014.

Wholesale Incentive Benchmark

Q. What is Tampa Electric's wholesale incentive benchmark for 2016, as derived in accordance with Order No. PSC-01-2371-FOF-EI, in Docket No. 010283-EI?

A. The company's 2016 benchmark is $1,563,273, which is the three-year average of $894,045, $3,298,966 and 496,810 actual gains on non-separated wholesale sales, excluding emergency sales, for 2013, 2014 and 2015, respectively.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

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

A. My name is Penelope A. Rusk. 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, Rates in the Regulatory Affairs Department.

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

A. I hold a Bachelor of Arts degree in Economics from the University of New Orleans and a Master of Arts degree in Economics from the University of South Florida. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, where I have assumed positions of increasing responsibility during my 19 years of electric utility experience, including load forecasting, managing cost recovery clauses, project management, and rate setting activities for wholesale and retail rate cases. My current duties include managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and approved environmental projects.

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 2016 through December 2016 fuel and purchased power and capacity actual/estimated true-up amounts to be recovered in the January 2017 through December 2017 projection period. My testimony addresses the recovery of fuel and purchased power costs as well as capacity costs for the year 2016, based on six months of actual data and six months of estimated data. This information will be used in the determination of the 2017 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. PAR-2, which consists of three documents. Document No. 1 includes 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 2016 through December 2016. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period of January 2016 through December 2016. Document No. 3 provides the actual/ estimated capital costs and fuel savings during the period of January 2016 through December 2016 for capital projects authorized for cost recovery through the fuel clause. Document No. 3 also provides the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for the project. 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 2017 through December 2017 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount applicable for the period January 2017 through December 2017 is an over-recovery of $122,639,796.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2017 through December 2017 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2017 is the sum of the final true-up amount for the period January 2015 through December 2015 and the actual/estimated true-up amount for the period January 2016 through December 2016.

Q. What did Tampa Electric calculate as the final fuel and purchased power cost recovery true-up amount for 2015?

A. The final true-up is an over-recovery of $18,058,299. The actual fuel cost over-recovery, including interest is $45,648,849 for the period January 2015 through December 2015. The $45,648,849 amount, less the actual/ estimated over-recovery amount of $27,590,550 approved in Order No. PSC-15-0586-FOF-EI, issued December 23, 2015 in Docket No. 150001-EI results in a net over-recovery amount for the period of $18,058,299.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2016 through December 2016?

A. The actual/estimated fuel and purchased power cost recovery true-up is an over-recovery amount of $104,581,497 for the January 2016 through December 2016 period. The detailed calculation supporting the actual/ estimated current period true-up is shown in Exhibit No. PAR-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 2017 through December 2017 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January 2017 through December 2017 is an under-recovery of $2,986,060 as shown in Exhibit No. PAR-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 2017 through December 2017 capacity cost recovery factors?

A. The net true-up amount to be recovered in the 2017 capacity cost recovery factors is the sum of the final true-up amount for 2015 and the actual/estimated true-up amount for January 2016 through December 2016.

Q. What did Tampa Electric calculate as the final capacity cost recovery true-up amount for 2015?

A. The final 2015 true-up is an under-recovery of $2,449,694. The actual capacity cost under-recovery including interest was $245,925 for the period January 2015 through December 2015. This amount, less the $2,203,769 actual/estimated over-recovery amount approved in Docket No. 150001-EI, Order No. PSC-15-0586-FOF-EI, issued December 23, 2015 results in a net under-recovery amount for the period of $2,449,694 as identified in Exhibit No. PAR-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 2016 through December 2016?

A. The actual/estimated true-up amount is an under-recovery of $536,366 as shown on Exhibit No. PAR-2, Document No. 2, page 1 of 5.

Capital Projects Approved for Fuel Clause Recovery

Q. Please describe the capital project costs that have been authorized for recovery through the fuel clause.

A. Document No. 3 of Exhibit No. PAR-2 provides the capital costs and fuel savings for the Polk Unit 1 and the Big Bend Units 1-4 ignition conversion projects for the period January 2016 through December 2016. This document also contains the capital structure components and cost rates relied upon to calculate the revenue requirements rate of return on capital projects recovered through the fuel clause.

The Polk Unit 1 ignition conversion project capital costs, including depreciation and return, for the period January 2016 through December 2016 are less than the project’s fuel savings. This is shown on Exhibit No. PAR-2, Document No. 3, page 1, line 33. Therefore, the Polk Unit 1 ignition conversion project capital costs should be recovered through the fuel clause in accordance with FPSC Order No. PSC-12-0498-PAA-EI, issued in Docket No. 120153-EI on September 27, 2012.

The Big Bend Units 1-4 ignition conversion project capital costs, including depreciation and return, for the period are less than the fuel savings resulting from the project, as shown on Exhibit No. PAR-2, Document No. 3, page 2, line 33. Therefore, the Big Bend Units 1-4 ignition conversion project capital costs should be recovered through the fuel clause in accordance with FPSC Order No. PSC-14-0309-PAA-EI, issued in Docket No. 140032-EI on June 12, 2014.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

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

A. My name is Penelope A. Rusk. 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, Rates in the Regulatory Affairs Department.

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

A. I hold a Bachelor of Arts degree in Economics from the University of New Orleans and a Master of Arts degree in Economics from the University of South Florida. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, where I have assumed positions of increasing responsibility during my 19 years of electric utility experience, including load forecasting, managing cost recovery clauses, project management, and rate setting activities for wholesale and retail rate cases. My duties include managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and approved environmental projects.

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 2017 through December 2017. I will also describe significant events that affect the factors and provide an overview of the composite effect on the residential bill of changes in the various cost recovery factors for 2017.

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

A. Yes. Exhibit No. PAR-3, consisting of four 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. Document

No. 2, which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, includes Schedules E1 through E10 for January 2017 through December 2017 as well as Schedule H1 for January through December, 2014 through 2017. 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. Document No. 4 presents the capital costs and fuel savings for the company's projects that have been approved for recovery through the fuel clause, as well as the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for the projects.

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. PAR-3, Document No. 1, page 3 of 4.

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

A. Tampa Electric is requesting recovery of capacity payments for power purchased for retail customers, excluding optional provision purchases for interruptible customers, through the capacity cost recovery factors. As shown in Exhibit No. PAR-3, Document No. 1, Tampa Electric requests recovery of $14,045,318 after jurisdictional separation, prior year true-up, and application of the revenue tax factor, for estimated expenses in 2017.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2017 through December 2017.

A.

Rate Class and Metering Voltage	Capacity Cost Cents per kWh	Recovery Factor $ per kW
RS Secondary	0.088	
GS and TS Secondary	0.076	
GSD, SBF Standard		
Secondary		0.27
Primary		0.27
Transmission		0.26
IS, IST, SBI		

Primary		0.14
Transmission		0.14
GSD Optional		
Secondary	0.063	
Primary	0.062	
LS1 Secondary	0.017	

These factors are shown in Exhibit No. PAR-3, Document No. 1, page 3 of 4.

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.074 cents per kWh compare to the factor for January 2016 through December 2016?

A. The proposed capacity cost recovery factor is 0.077 cents per kWh (or $0.77 per 1,000 kWh) lower than the average capacity cost recovery factor of 0.151 cents per kWh for the January 2016 through December 2016 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 2017?

A. The appropriate amount for the 2017 period is 2.956 cents per kWh before the application of time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. PAR-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 2017 through December 2017.

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 $969,593, which is included in the calculation of the total fuel and purchased power cost recovery factors. In addition, Schedule E1-C indicates the net true-up amount for the January 2016 through December 2016 period. The net true-up amount for this period is an over-recovery of $122,639,796.

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 2017 through December 2017. 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. PAR-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 2017 through December 2017.

A.

Metering Voltage Level	Fuel Charge Factor (cents per kWh)
Secondary	2.956
Tier I (Up to 1,000 kWh)	2.642
Tier II (Over 1,000 kWh)	3.642
Distribution Primary	2.926

Transmission	2.897	
Lighting Service	2.916	
Distribution Secondary	3.166	(on-peak)
	2.865	(off-peak)
Distribution Primary	3.134	(on-peak)
	2.836	(off-peak)
Transmission	3.103	(on-peak)
	2.808	(off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 2.956 cents per kWh compare to the levelized fuel adjustment factor for the January 2016 through December 2016 period?

A. The proposed fuel charge factor is 0.720 cents per kWh (or $7.20 per 1,000 kWh) lower than the average fuel charge factor of 3.676 cents per kWh for the January 2016 through December 2016 period.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2017 fuel and purchased power and capacity cost recovery projections?

A. Yes, the company's highly efficient Polk 2 combined cycle

("CC") unit is anticipated to begin commercial service in January 2017. The unit will provide reliable and efficient natural gas-fired generation for customers. As stated in the testimony of Tampa Electric witness J. Brent Caldwell, the company did not require new natural gas supply or transportation agreements to serve this unit, due to the flexibility of the company's existing natural gas supply portfolio.

Capital Projects Approved for Fuel Clause Recovery

Q. What did Tampa Electric calculate as the estimated Polk Unit 1 ignition oil conversion project costs for the period January 2017 through December 2017?

A. The estimated Polk Unit 1 ignition oil conversion project capital costs, including depreciation and return, for the period of January 2017 through December 2017 are $3,518,938. This is shown in Exhibit No. PAR-3, Document No. 4.

Q. Does Tampa Electric's estimated Polk Unit 1 ignition oil conversion project fuel savings exceed estimated costs for the period January 2017 through December 2017?

A. Yes, as reflected in Exhibit No. PAR-3, Document No. 4, fuel savings exceed costs for the period January 2017 through December 2017.

Q. Should Tampa Electric's Polk Unit 1 ignition oil conversion project capital costs be recovered through the fuel clause?

A. Yes. The January 2017 through December 2017 estimated fuel savings are greater than the project capital costs, providing an expected net benefit to customers, and the costs are eligible for recovery through the fuel clause in accordance with FPSC Order No. PSC-12-0498-PAA-EI, issued in Docket No. 120153-EI on September 27, 2012.

Q. What did Tampa Electric calculate as the estimated Big Bend Units 1-4 ignition oil conversion project costs for the period January 2017 through December 2017?

A. The estimated Big Bend Units 1-4 ignition oil conversion project capital costs, including depreciation and return, for the period of January 2017 through December 2017 are $5,260,518. This is shown in Document No. 4 of my exhibit.

Q. Does Tampa Electric's estimated Big Bend ignition oil conversion project fuel savings exceed estimated costs for the period of January 2017 through December 2017?

A. Yes, fuel savings exceed costs for the period January 2017 through December 2017. This information is also presented in Document No. 4 of my exhibit.

Q. Should Tampa Electric's Big Bend Units 1-4 ignition oil conversion project capital costs be recovered through the fuel clause?

A. Yes. The January 2017 through December 2017 estimated fuel savings are greater than the project capital costs, providing an expected net benefit to customers, and the costs are eligible for recovery through the fuel clause in accordance with FPSC Order No. PSC-14-0309-PAA-EI, issued in Docket No. 140032-EI on June 12, 2014.

Q. Please describe the capital structure components and cost rates used to calculate the revenue requirement rate of return for these two projects.

A. The capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for the company's projects that are approved for recovery through the fuel clause are shown in Document No. 4.

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric's projected wholesale incentive benchmark for 2017?

A. The company's projected 2017 benchmark is $1,337,579, which is the three-year average of $3,298,966, $496,810 and $216,961 in gains on the company's non-separated wholesale sales, excluding emergency sales, for 2014, 2015 and 2016 (actual/estimated), respectively.

Q. Does Tampa Electric expect gains in 2017 from non-separated wholesale sales to exceed its 2017 wholesale incentive benchmark?

A. No. Tampa Electric anticipates that sales will not exceed the projected benchmark for 2017. Therefore, all sales margins are expected to flow back to customers.

Cost Recovery Factors

Q. What is the composite effect of Tampa Electric's proposed changes in its base, 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 $1.54 beginning January 2017, when compared to the January 2016 through December 2016 charges. These charges are shown in Exhibit No. PAR-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 2017.

Q. Does this conclude your testimony?

A. Yes, it does.

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, Compliance and Performance.

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 2008, I was promoted to Manager, Operations Planning. Currently, I am the Manager of Compliance and Performance responsible for 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 heat rate used to determine the Generating Performance Incentive Factor ("GPIF") for the period January 2015 through December 2015. I will also compare these results to the targets established for 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 "GPIF Schedules" 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 2015 period.

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

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

Q. Have you calculated the results of Tampa Electric's performance under the GPIF during the January 2015 through December 2015 period?

A. Yes, I have. This is shown on Document No. 1, page 4 of 32. Based upon 1.259 Generating Performance Incentive Points ("GPIP"), the result is a reward amount of $969,593 for the period.

Q. Please proceed with your review of the actual results for the January 2015 through December 2015 period.

A. On Document No. 1, page 3 of 32, the actual average common equity for the period is shown on line 14 as $2,170,178,414. This produces the maximum penalty or reward amount of $7,702,537 as shown on line 23.

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, 2,016.0 planned outage hours were originally scheduled for 2015. Actual outage activities required 2,363.7 planned outage hours. Consequently, the actual equivalent availability of 59.0 percent is adjusted to 62.2 percent as shown on Document No. 1, page 7 of 32.

Big Bend Unit No. 2

On this unit, 576.0 planned outage hours were originally scheduled for 2015. Actual outage activities required 654.1 planned outage hours. Consequently, the actual equivalent availability of 45.8 percent is adjusted to 46.2 percent as shown on Document No. 1, page 8 of 32.

Big Bend Unit No. 3

On this unit, 576.0 planned outage hours were originally scheduled for 2015. Actual outage activities required 328.0 planned outage hours. Consequently, the actual equivalent availability of 72.2 percent is adjusted to 70.0 percent as shown on Document No. 1, page 9 of 32.

Big Bend Unit No. 4

On this unit, 576.0 planned outage hours were originally scheduled for 2015. Actual outage activities required 334.1 planned outage hours. Consequently, the actual equivalent availability of 81.1 percent is adjusted to 78.7 percent as shown on Document No. 1, page 10 of 32.

Polk Unit No. 1

On this unit, 1,200.0 planned outage hours were originally scheduled for 2015. Actual outage activities required 1,178.4 planned outage hours. Consequently, the actual equivalent availability of 70.5 percent is adjusted to 70.3 percent, as shown on Document No. 1, page 11 of 32.

Bayside Unit No. 1

On this unit, 432.0 planned outage hours were originally scheduled for 2015. Actual outage activities required 1,032.8 planned outage hours. Consequently, the actual equivalent availability of 85.9 percent is adjusted to 92.6 percent, as shown on Document No. 1, page 12 of 32.

Bayside Unit No. 2

On this unit, 528.0 planned outage hours were originally scheduled for 2015. Actual outage activities required 627.1 planned outage hours. Consequently, the actual equivalent availability of 89.2 percent is adjusted to 90.3 percent, as shown on Document No. 1, page 13 of 32.

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

A. The final adjusted equivalent availabilities for each unit are shown on Document No. 1, page 6 of 32, column 4. This number is entered into the respective GPIP table for each particular unit, shown on pages 24 of 32 through 30 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 24 through 30 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 2015 through December 2015 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, 1.259, is then entered into the GPIF table on page 2 of 32. Using linear interpolation, the reward amount is $969,593.

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. Tampa Electric met this constraint, limiting the total potential reward and penalty incentive dollars to $7,702,537, as shown in Document No. 1, Pages 2 and 3.

Q. Does this conclude your testimony?

A. Yes, it does.

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, Compliance and Performance.

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. Currently, I am the Manager of Compliance and Performance responsible for unit performance analysis and reporting of generation statistics.

Q. What is the purpose of your testimony?

A. My testimony describes 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 2017 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. In accordance with the GPIF Manual, the GPIF units selected represent no less than 80 percent of the estimated system net generation. The units Tampa Electric proposes to use for the period January 2017 through December 2017 represent the top 99 percent of the total forecasted system net generation for this period excluding the new Polk 2 combined cycle unit ("Polk Unit 2 CC"). The Polk Unit 2 CC is expected to enter commercial service in January 2017 and was excluded from the GPIF calculation because the company does not have historical operational data on which to base targets.

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. 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. Big Bend Unit 1 and Big Bend Unit 2 forced outages were identified as outlying outages; therefore, the associated forced outage hours were removed from the study.

Q. Did Tampa Electric make any other adjustments?

A. Yes. As allowed per Section 4.3 of the GPIF Implementation Manual, the Forced Outage and Maintenance Outage Factors were adjusted to reflect recent unit performance and known unit modifications or equipment changes. Big Bend Units 1-4 and Polk Unit 1 heat rates were adjusted to reflect natural gas and coal co-firing.

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 2017 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 2017 period, the projected EUOF for Bayside Unit 2 is 4.4 percent, and the POF is 19.5 percent. Therefore, the target EAF for Bayside Unit 2 equals 76.1 percent or:

$$100\% - (4.4\% + 19.5\%) = 76.1\%$$

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:

$$EAF_{MAX} = 1 - [0.80 \ (EUOF_T) + 0.95 \ (POF_T)]$$

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, plus a five percent reduction in the POF are necessary. Continuing with the Bayside Unit 2 example:

$$EAF_{MAX} = 1 - [0.80 \ (4.4\%) + 0.95 \ (19.5\%)] = 78.0\%$$

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 Bayside Unit 2 example,

$$EAF_{MIN} = 1 - [1.40 \ (4.4\%) + 1.10 \ (19.5\%)] = 72.4\%$$

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 2017 are shown on page 21 of Document No. 1. Three GPIF units have a major outage of 28 days or greater in 2017; therefore, three Critical Path Method diagrams are provided. Planned Outage Factors are calculated for each unit. For example, Bayside Unit 2 is scheduled for a planned outage from April 15, 2017 to April 29, 2017 and September 26, 2017 to November 20, 2017. There are 1,705 planned outage hours scheduled for the 2017 period, and a total of 8,760 hours during this 12-month period. Consequently, the POF for Bayside Unit 2 is 19.5 percent or:

$$\frac{1,705}{8,760} \times 100\% = 19.5\%$$

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 6.6 percent. Big Bend Unit 2 has a POF of 6.6 percent. Big Bend Unit 3 has a POF of 21.9 percent. Big Bend Unit 4 has a POF of 6.6 percent. Polk Unit 1 has a POF of 7.4 percent. Bayside Unit 1 has a POF of 18.6 percent, and Bayside Unit 2 has a POF of 19.5 percent.

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

A. Projected factors are based upon historical unit performance. For each unit the three most recent July through June annual periods formed the basis of the target development. Historical data and target values are analyzed to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or recent trends having material effect can be taken into consideration. These target factors are additive and result in a EUOF of 4.4 percent for Bayside Unit 2. The EUOF for Bayside Unit 2 is verified by the data shown on page 20, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

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

or

$$EUOF = \frac{(135 + 255)}{8,760} \times 100\% = 4.4\%$$

Relative to Bayside Unit 2, the EUOF of 4.4 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 12.9 percent. The unit will have two planned outages in 2017, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 80.5 percent.

Big Bend Unit 2

The projected EUOF for this unit is 23.8 percent. The unit will have two planned outages in 2017, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 69.6 percent.

Big Bend Unit 3

The projected EUOF for this unit is 16.7 percent. The unit will have two planned outages in 2017, and the POF is 21.9 percent. Therefore, the target equivalent availability for this unit is 61.4 percent.

Big Bend Unit 4

The projected EUOF for this unit is 14.3 percent. The unit will have two planned outages in 2017, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 79.1 percent.

Polk Unit 1

The projected EUOF for this unit is 10.5 percent. The unit will have two planned outages in 2017, and the POF is 7.4 percent. Therefore, the target equivalent availability for this unit is 82.1 percent.

Bayside Unit 1

The projected EUOF for this unit is 6.1 percent. The unit will have two planned outages in 2017, and the POF is 18.6 percent. Therefore, the target equivalent availability for this unit is 75.3 percent.

Bayside Unit 2

The projected EUOF for this unit is 4.4 percent. The unit will have two planned outages in 2017, and the POF is 19.5 percent. Therefore, the target equivalent availability for this unit is 76.1 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 74.4 percent is shown on Page 5 of Document No. 1.

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 cannot 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 Bayside Unit 2 on page 20 of Document No. 1. Except for the months of April, September, and November, the Equivalent Unplanned Outage

Rate and the Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled during these months. During the months of April, September, and November, the Equivalent Unplanned Outage Rate exceeds the Equivalent Unplanned Outage Factor 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 and co-firing.

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 and fuel.

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 2017 period.

A. The heat rate target for Big Bend Unit 1 is 10,698 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ± 289 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,545 Btu/Net kWh with a range of ± 447 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,588 Btu/Net kWh, with a range of ± 264 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,447 Btu/Net kWh with a range of ± 204 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,048 Btu/Net kWh with a range of ± 520 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,517 Btu/Net kWh with a range of ± 135 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,683 Btu/Net kWh with a range of ± 179 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 $695,758,070 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 $18,187,737 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 Bayside Unit 2, the weighting factor for average net operating heat rate is 12.03 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 Bayside Unit 2, page 13, if the unit operates at 7,504 average net operating heat rate, fuel savings would equal $2,187,738 and +10 average net operating heat rate 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 $18,187,737. 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 2017 is $2,455,955,733. This produces the maximum allowed jurisdictional incentive of $10,013,992 shown on line 21.

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

A. Yes. As Order No. PSC-13-0665-FOF-EI issued in Docket No. 130001-EI on December 18, 2013 states, incentive dollars are not to exceed 50 percent of fuel savings.

Page 2 of Document No. 1 demonstrates that this constraint is met, limiting total potential reward and penalty incentive dollars to $9,093,869.

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):

$$
\begin{aligned}
GPIP: = (&0.0661\ EAP_{BB1} + 0.0870\ EAP_{BB2} \\
&+ 0.0555\ EAP_{BB3} + 0.0782\ EAP_{BB4} \\
&+ 0.0429\ EAP_{PK1} + 0.0274\ EAP_{BAY1} \\
&+ 0.0062\ EAP_{BAY2} + 0.0922\ HRP_{BB1} \\
&+ 0.1261\ HRP_{BB2} + 0.0625\ HRP_{BB3} \\
&+ 0.0720\ HRP_{BB4} + 0.0701\ HRP_{PK1} \\
&+ 0.0933\ HRP_{BAY1} + 0.1203\ HRP_{BAY2})
\end{aligned}
$$

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 2017 period?

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

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH II

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

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

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

A. I received a Bachelor of Science degree in Electric Engineering in 1991 from the University of South Florida in Tampa, Florida and a Master of Business Administration degree in 2015 from Saint Leo University in Saint Leo, Florida. I am also a registered Professional Engineer within the State of Florida and a Certified Energy Manager through the Association of Energy Engineers. 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 Wholesale Business Development in Tampa Electric's Fuels Management department. My responsibilities are to evaluate short- and long-term purchase and sale opportunities within the wholesale power market, assist in wholesale origination and contract structures, and help evaluate the processes used to value potential wholesale power transactions. In this capacity, I interact with wholesale power market participants such as utilities, municipalities, electric cooperatives, power marketers, and other wholesale developers and independent power producers.

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 power purchase agreements 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 purchase 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 Tampa Electric considers making a power purchase, the company aggressively searches for available supplies of wholesale capacity or energy from creditworthy counterparties. The objective is to secure reliable quantities of purchased power for customers at the best possible price.

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 and improve reliability. 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 2016 wholesale power purchases.

A. Tampa Electric assessed the wholesale power market and entered into short- and long-term purchases based on price and availability of supply. Approximately ten percent of the company's expected energy needs for 2016 will be met using purchased power. This includes economy energy purchases, purchases from qualifying facilities, and pre-existing firm purchased power agreements with Pasco Cogen and Calpine. The company also entered three additional firm power purchase agreements with Duke Energy Florida

("Duke"), Florida Power & Light ("FPL"), and Exelon Generation Company, formerly known as Constellation Energy Commodities Group ("Exelon").

My testimony in previous years' dockets described the agreements with Pasco Cogen and Calpine. However, in summary, both pre-existing purchases are call options with dual-fuel (*i.e.*, natural gas or oil) capability. The Pasco Cogen purchase is for 121 MW of intermediate capacity and continues through 2018, and the Calpine agreement is a peaking purchase with a capacity of 117 MW. The Calpine purchase continues through 2016. These two purchases were previously approved by the Commission as being cost-effective for Tampa Electric customers.

The three new power purchase agreements sum to 500 MW of capacity and are of various sizes and end dates, the last of which concludes in February 2017. The Duke purchase is for250 MW of efficient combined-cycle capacity for the term February 2016 through February 2017. The FPL purchase is for 100 MW of system capacity for the period May through November 2016, and the Exelon purchase is for 150 MW of efficient combined-cycle capacity, also for the period May through November 2016.

Q. How did Tampa Electric determine that the three new purchases were the most beneficial options for Tampa Electric's customers?

A. As stated in my 2016 projection testimony, the Commission approved Tampa Electric's determination of need for the Polk Unit 2-5 combined cycle conversion ("Polk Unit 2 CC") in Docket No. 120234-EI. Polk Unit 2 CC is expected to begin commercial service in January 2017, and its construction timeline often requires at least two of the existing 150 MW Polk combustion turbine ("CT") units to be unavailable from May through November of this year for combined cycle tie-in and testing. This tie-in and testing requirement created a projected need for capacity and energy to meet system reserve margin requirements and ensure operational flexibility. Therefore, Tampa Electric included a 300 MW purchase in the 2016 projected costs submitted in Docket No. 150001-EI.

On August 31, 2015, Tampa Electric issued a market solicitation for proposals to provide the needed firm power, with the objective of securing necessary purchased power for customers at the best possible price. Upon evaluating the solicitation responses and the company's demand and energy forecasts, Tampa Electric secured 500 MW of capacity purchases over varying periods at terms more economical for customers than the projected costs included in the 2016 projection submitted in Docket No. 150001-EI. This allowed Tampa Electric to make the purchases both for economics and to ensure reliability while various CTs at Polk were unavailable for equipment tie-in and testing activities.

The terms of the FPL and Exelon transactions are coincident with the projected Polk CT tie-in and testing activities. The Duke transaction extends beyond the duration of the projected construction testing. After consideration of the favorable terms for this purchase, it was more cost-effective to Tampa Electric and its customers to start the purchase in February of 2016 and extend it through February of 2017. Notably, the Duke purchase is within the Tampa Electric balancing authority area. Thus, the purchase has the economic benefit of having no transmission wheeling costs.

All three new purchases are needed to help meet Tampa Electric’s reserve margin needs during the Polk Unit 2 CC construction window in 2016 and together provide a fuel savings to customers of approximately $8 million on an energy basis. These new purchases are prudent and beneficial for customers, and the company asks the Commission to approve them for cost recovery.

All of the aforementioned purchases provide supply reliability and help reduce energy price volatility. In addition to these purchases, Tampa Electric will continue to evaluate economic combinations of forward and spot market energy purchases during the company's peak periods and spring and fall generation maintenance periods. This purchasing strategy provides a reasonable and diversified approach to serving customers.

Q. Has Tampa Electric entered into any other wholesale energy purchases beyond 2016?

A. No.

Q. Does Tampa Electric anticipate entering into any other new wholesale energy purchases for 2017 and beyond?

A. Although Tampa Electric does not anticipate making other long-term purchases at this time, the company always evaluates the merits of long-term purchases as opportunities are presented. In doing so, Tampa Electric will consider entering into additional long-term purchases that bring value to customers. In addition, Tampa Electric will continue to evaluate and utilize economically the short-term purchased power market, as part of its purchasing strategy for 2017 and beyond. Currently, Tampa Electric expects purchased power to meet approximately two percent of its 2017 energy needs. This energy includes contributions from the previously mentioned firm purchases.

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 no Florida trading hub exists where standard financial transactions can occur with enough volume to create a liquid market. Due to this lack of liquidity and standard financial instruments, Tampa Electric has not purchased any financial wholesale power hedges. However, the company employs a diversified physical power supply strategy, which includes self-generation and short- and long-term capacity and energy purchases. This strategy provides the company the opportunity to take advantage of favorable spot market pricing while maintaining reliable service to its customers.

Q. Does Tampa Electric's risk management strategy for power transactions adequately mitigate price risk for purchased power in 2016?

A. Yes, Tampa Electric expects its physical wholesale purchases to continue to reduce its customers' purchased power price risk. For instance, the 121 MW purchased from Pasco Cogen and 117 MW from Calpine are reliable, cost-based call options for power. Likewise, the same sentiment applies for the three new firm purchases. The Duke purchase is from the Osprey combined cycle within the Tampa Electric balancing authority area and provides economic natural-gas energy. The FPL purchase is a system product, which not only provides economic energy but also has greater reliability than a single unit source. Similarly, the Exelon product is a site-wide purchase from a multi-unit natural gas combined cycle facility, which makes it more reliable than a single unit purchase in addition to being economic. These purchases serve as both a physical hedge and reliable source of economic power. 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 continues to evaluate its options in light of changing circumstances and new opportunities. Tampa Electric also maintains a mix of short- and long-term capacity and energy purchases to augment the company's own generation for the year 2016 and beyond.

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

A. During hurricane season, Tampa Electric continues to utilize a purchased power risk management strategy to minimize potential power supply disruptions. 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 sellers' fuel sources and dual-fuel capabilities; and focusing on fuel-diversified purchases. Notably, the company's Pasco Cogen and Calpine power agreements are from 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. Also, the FPL purchase, being a system product, helps mitigate power supply risks that may arise because of unavailability of a specific fuel type. Absent the threat of a hurricane, and for all other months of the year, the company evaluates economic combinations of short- and long-term purchase opportunities in the marketplace.

Q. Please describe Tampa Electric's wholesale energy sales for 2016 and 2017.

A. Tampa Electric entered into various non-separated wholesale sales in 2016, and the company anticipates making additional non-separated sales during the balance of 2016 and in 2017. The gains from these sales are distributed among Tampa Electric and its customers in accordance with the company's current incentive mechanism established in Order No. PSC-01-2371-FOF-EI, issued on December 7, 2001 in Docket No. 010283-EI. The current incentive mechanism provides that all gains from non-separated sales be 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 2016, Tampa Electric projects the company’s gains from non-separated wholesale sales to be $216,961, which is less than the 2016 threshold of $1,563,273. Therefore, Tampa Electric expects customers to receive 100 percent of the 2016 non-separated sales gains. Likewise, in 2017, the company projects gains to be $47,795, of which customers would receive 100 percent, since the amount is less than the 2017 projected three-year rolling average threshold of $1,337,579.

Q. Please summarize your testimony.

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

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

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

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

A. I received a Bachelor's degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science degree in Electrical Engineering in 1988 from the University of South Florida. I have over 20 years of utility experience with an emphasis in state and federal regulatory matters, fuel procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October 2010, I assumed responsibility for long term fuel supply planning and procurement for Tampa Electric's generating stations.

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

A. Yes. I have submitted written testimony in the annual fuel docket since 2011. In 2015, I testified in Docket No. 150001-EI on the subject of natural gas hedging. I have also testified before the Commission in Docket No. 120234-EI regarding the company's fuel procurement for the Polk 2-5 Combined Cycle Conversion project.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present, for the Commission's review, information regarding the 2015 results of Tampa Electric's risk management activities, as required by the terms of the stipulation entered into by the parties to Docket No. 011605-EI and approved by the Commission in Order No. PSC-02-1484-FOF-EI.

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

A. Yes. Exhibit No. ___ (JBC-1), entitled Tampa Electric's

2015 Hedging Activity True-up, was prepared under my direction and supervision. This report explains the company's risk management activities and results for the calendar year 2015.

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 2015?

A. As outlined in Tampa Electric's 2015 Hedging Activity True-up, filed as an exhibit to this testimony, the company follows a non-speculative risk management strategy to reduce fuel price volatility while maintaining a reliable supply of fuel. In particular, Tampa Electric established a financial hedging program to limit customers' exposure to spikes in the price of natural gas. Over time, this program has been enhanced as Tampa Electric's gas needs have evolved and grown. All enhancements have been reviewed and approved by the company's Risk Authorization Committee.

The report indicates that Tampa Electric's 2015 hedging activities resulted in a net mark-to-market loss of approximately $39.8 million. These results are due to the market conditions experienced in the past year. Natural gas prices decreased significantly in late 2014 and all of 2015 due to mild winters, abundant natural gas production and nearly full natural gas storage at the end of the summer injection season. The decrease in prices over the hedging time horizon resulted in a mark-to-market loss. However, the hedges were successful in achieving the plan objective of reducing price volatility while maintaining a reliable fuel supply.

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

A. No, Tampa Electric does not hedge natural gas pricing through physical gas supply contracts. Tampa Electric does hedge its natural gas supply through diversification. Tampa Electric also physically hedges its supply through the use of a variety of sources, delivery methods, inventory locations and contractual terms to enhance the company's supply reliability and flexibility to cost-effectively meet changing operational needs.

Tampa Electric continually pursues new creditworthy counterparties and maintains contracts for gas supplies from various regions and on different pipelines. The company also contracts for pipeline capacity to access non-conventional shale gas production which is less sensitive to interruption by hurricanes. Additionally, Tampa Electric has storage capacity with Bay Gas Storage near Mobile, Alabama. All of these actions enhance the effectiveness of Tampa Electric's gas supply portfolio.

Q. Does Tampa Electric use a hedging information system?

A. Yes, until recently, Tampa Electric has used Sungard's Nucleus Risk Management System ("Nucleus"). In 2013, Tampa Electric initiated a project to replace Nucleus with Allegro. The natural gas portion of the Allegro project replaced Nucleus for all natural gas financial and physical transactions effective November 1, 2014. The wholesale power portion of the Allegro project replaced the in-house system on October 1, 2015. Allegro supports sound hedging practices with its contract management, separation of duties, credit tracking, transaction limits, deal confirmation, risk exposure analysis and business report generation functions. The Allegro system records all financial natural gas hedging transactions, and the system calculates risk management reports.

Q. Did the company use financial hedges for commodities other than natural gas in 2015?

A. No. Tampa Electric did not use financial hedges for commodities other than natural gas in 2015.

Tampa Electric's generation comprises mostly coal and natural gas. The price of coal has historically been stable compared to the prices of oil and natural gas. In addition, there is not an organized, nor a liquid, market for financial hedging instruments for the high-sulfur Illinois Basin coal that Tampa Electric uses at Big Bend Station, its largest coal-fired generation facility.

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

Similarly, Tampa Electric did not use financial hedges for wholesale power transactions because a liquid, published market does not exist for power in Florida.

Q. How does Tampa Electric assure physical supply of other commodities?

A. Tampa Electric assures sufficient physical supply of coal and oil through supply diversification, inventory sufficiency, and delivery flexibility. For coal, the company enters into a portfolio of contracts with differing terms and various suppliers to obtain the types of coal used in its electric generation system. Through a competitive bid process, supplier diversity and transportation flexibility, Tampa Electric is able to obtain competitive prices with valuable quality and transportation flexibility by selecting from a wide range of purchase options.

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

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

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

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 160001-EI
FILED: 8/4/2016

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

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

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

A. I received a Bachelor's degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science degree in Electrical Engineering in 1988 from the University of South Florida. I have over 20 years of utility experience with an emphasis in state and federal regulatory matters, fuel procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October 2010, I assumed responsibility for long term fuel supply planning and procurement for Tampa Electric’s generating stations.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor and describe Exhibit No. JBC-2, entitled Tampa Electric Company’s Fuel Procurement and Wholesale Power Purchases Risk Management Plan 2017.

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

A. Yes, it was.

Q. Please describe your exhibit.

A. My Exhibit No. JBC-2 provides Tampa Electric’s overall plan for mitigating risk in the company’s procurement of fuel and purchased power during 2017.

Q. Did Tampa Electric make changes to its 2017 risk management plan pursuant to Order No. PSC-16-0247-PAA-EI, issued June 27, 2016?

A. No. Office of Public Counsel ("OPC") filed a protest of Order No. PSC-16-0247-PAA-EI within the protest period. Therefore, the company did not update its risk management plan in accordance with the order, pending resolution of the protest.

Q. Since Order No. PSC-16-0247-PAA-EI was issued, has the company changed its position on reducing the percentage of projected natural gas usage to be hedged?

A. No, the company has not changed its position. Tampa Electric remains willing to reduce the duration of hedges and percentage of natural gas hedged by the amount that the Commission deems beneficial for consumers. The sole reason that the company has not modified its 2017 risk management plan in response to Order No. PSC-16-0247-PAA-EI is that it is the company's understanding that the protest filed by OPC prevents the order from taking effect at this time.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

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

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

A. I received a Bachelor Degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science degree in Electrical Engineering in 1988 from the University of South Florida. I have over 20 years of utility experience with an emphasis in state and federal regulatory matters, natural gas procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October 2010, I assumed responsibility for long term fuel supply planning and procurement for Tampa Electric’s generating stations.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor and describe my Exhibit No. JBC-3, entitled Tampa Electric Natural Gas Hedging Activities, January 1, 2016 through July 31, 2016.

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

A. Yes, it was.

Q. Please describe your exhibit.

A. My Exhibit No. JBC-3 shows details of Tampa Electric's hedging activities for natural gas for the seven-month period January through July 2016.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

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

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

A. I received a Bachelor's degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science degree in Electrical Engineering in 1988 from the University of South Florida. I have over 20 years of utility experience with an emphasis in state and federal regulatory matters, fuel procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October 2010, I assumed responsibility for long-term fuel supply planning and procurement for Tampa Electric's generating stations.

Q. Have you previously testified before this Commission?

A. Yes. I have submitted written testimony in the annual fuel docket since 2011. In 2015, I testified in Docket No. 150001-EI on the subject of natural gas hedging. I have also testified before the Commission in Docket No. 120234-EI regarding the company's fuel procurement for the Polk 2-5 Combined Cycle ("CC") Conversion project.

Q. What is 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.

Fuel Mix and Procurement Strategies

Q. What fuels do Tampa Electric's generating stations use?

A. Tampa Electric's fuel mix includes coal, natural gas, and oil. Coal is the primary fuel for Big Bend Station, and natural gas is a secondary fuel. The Polk Unit 1 integrated gasification combined-cycle unit utilizes coal as the primary fuel and natural gas as a secondary fuel; and Bayside Station combined-cycle units and the company's collection of peakers (*i.e.*, simple cycle and aero-derivative combustion turbines) utilize natural gas. Some of Tampa Electric's peakers utilize oil as a secondary fuel, but oil consumption as a percentage of system generation is minute (*i.e.*, less than one percent). During the first half of 2016, very low natural gas prices resulted in greater use of natural gas, compared to the original projection. Based upon the 2016 actual-estimate projections, the company expects 2016 total system generation to be 42 percent coal and 58 percent natural gas, with oil making up a fraction of a percentage point.

In 2017, coal-fired and natural gas-fired generation are expected to be approximately 47 percent and 53 percent of total generation, respectively. Generation from oil is expected to remain less than one percent of the total generation.

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

A. Tampa Electric emphasizes flexibility and options in its fuel procurement strategy for all of its fuel needs. The company strives to maintain a large number of creditworthy and viable suppliers. Similarly, the company endeavors to maintain multiple delivery path options. Tampa Electric also attempts to diversify the locations from which its supply is sourced. Having a greater number of fuel supply and delivery options provides increased reliability and lower costs for Tampa Electric's customers.

Coal Supply Strategy

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

A. Tampa Electric uses solid fuel for the four pulverized-coal steam turbine units at Big Bend Station and as the primary fuel for the integrated gasification combined cycle Polk Unit 1. The coal-fired units at Big Bend Station are fully scrubbed for sulfur dioxide and nitrogen oxides and are designed to burn high-sulfur Illinois Basin coal. Polk Unit 1 currently burns a mix of petroleum coke and low sulfur coal. Each plant has varying operational and environmental restrictions and requires fuel with custom quality characteristics such as ash content, fusion temperature, sulfur content, heat content, and chlorine content. Coal is not a homogenous product, and the variability of the product dictates Tampa Electric select fuel based on multiple parameters. Those parameters include unique coal characteristics, price, availability, deliverability, and creditworthiness of the supplier.

To minimize costs, maintain operational flexibility, and ensure reliable supply, Tampa Electric maintains a portfolio of bilateral coal supply contracts with varying term lengths. 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 short- and long-term market conditions. Tampa Electric's strategy provides a stable supply of reliable fuel sources while still allowing the company the flexibility to take advantage of favorable spot market opportunities and address operational needs.

Q. Please summarize Tampa Electric's solid fuel, coal, and petroleum coke supply through 2017.

A. Tampa Electric supplies Big Bend Station's coal needs through a combination of three coal supply agreements that continue through 2017 and a collection of shorter term contracts and spot purchases. These shorter term purchases allow the company to adjust supply to reflect changing coal quality and quantity needs, operational changes and pricing opportunities.

Q. Has Tampa Electric entered into coal supply transactions for 2017 delivery?

A. Yes, Tampa Electric has contracted for and has available from inventory over 75 percent of its 2017 expected coal needs through agreements with coal suppliers to mitigate price volatility and ensure the reliability of supply. Tampa Electric anticipates the remaining solid fuel consumption for Big Bend Station and Polk Unit 1 will be procured through spot market purchases or consumed from inventory during 2016 and 2017.

Coal Transportation

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

A. Tampa Electric can receive coal at its Big Bend Station via waterborne or rail delivery. Once delivered to Big Bend Station, Polk Unit 1 solid fuel is trucked to Polk Station.

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

A. Transportation options provide benefits to customers. Bimodal solid fuel transportation to Big Bend Station affords the company and its customers 1) access to more potential coal suppliers providing a more competitively priced and diverse, delivered coal portfolio, 2) the opportunity 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. Will Tampa Electric continue to receive coal deliveries via rail in 2016 and 2017?

A. Yes. Tampa Electric expects to receive coal for use at Big Bend Station through the Big Bend rail facility during 2016 and is in the process of evaluating how much coal to receive by rail in 2017.

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

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

Q. Please describe the replacement for the river barge transportation contract with a term ending December 31, 2016.

A. One of two river barge transportation agreements expire at the end of 2016. Tampa Electric is currently assessing the most economic replacement option for this agreement. Due to the flexibility in the company's delivery and supply portfolio, Tampa Electric can meet its 2017 solid fuel delivery needs without replacing this agreement.

Q. Please describe any other changes to the solid fuel transportation agreements.

A. Tampa Electric has taken advantage of a number of spot market transportation opportunities. Tampa Electric has used delivered coal, a different river transportation provider, and three new terminals during 2016 to manage its portfolio during changing coal consumption levels, increase reliability during outages, and increase flexibility in its supply and transportation portfolio.

Q. Do you have any other updates to provide with regard to Tampa Electric’s solid fuel transportation portfolio?

A. Tampa Electric monitors the financial strength and ability to perform of its solid fuel suppliers and transportation providers. On August 1, 2016 United Ocean Services (“UOS”), Tampa Electric’s gulf transportation provider, filed for protection under Chapter 11 bankruptcy law. While this has not become a performance issue yet and Tampa Electric believes UOS fully intends to emerge from the filing as an operationally sufficient and financially stronger transportation service provider, the company must consider the uncertainty of UOS’s future. Tampa Electric is closely monitoring the situation, actively engaged in communication with UOS, and developing contingency plans to ensure reliable and cost-effective solid fuel supply to its power plants. Tampa Electric expects UOS to continue to provide service as the bankruptcy hearings proceed. It is likely that at least several months will pass before more definitive information about the UOS bankruptcy outcome is available.

Q. Please describe any other significant factors that Tampa Electric considered in developing its 2017 solid fuel supply portfolio.

A. Tampa Electric continues to place an emphasis on flexibility in its solid fuel supply portfolio. The company recognizes that several factors may impact the annual consumption of solid fuel. New or pending environmental regulations may affect the types of coal, the quantities of coal that can be consumed at the stations or, most likely, both. Also, the use of different types of fuel within the state continue to evolve as generation assets are built, upgraded or retired. For instance, Tampa Electric's Polk Unit 2 CC is anticipated to enter commercial service in January 2017. The Polk Unit 2 CC project converts the existing natural gas combustion turbines at Polk Power Station into a very efficient natural gas combined-cycle unit. Similarly, several new natural gas combined-cycle units recently have been built within the state. Depending on the relative price of delivered solid fuel, delivered natural gas and the dynamics of the wholesale power market, the actual quantity of solid fuel burned may vary significantly each year. Tampa Electric strives to balance the need to have reliable solid fuel commodity and transportation while mitigating the potential for significant shortfall penalties if the commodity or transportation is not needed.

Natural Gas Supply Strategy

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

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

Tampa Electric diversifies its pipeline transportation assets, including receipt points. The company also utilizes pipeline and storage tools to enhance access to natural gas supply during hurricanes or other events that constrain supply. Such actions improve the reliability and cost effectiveness of the physical delivery of natural gas to the company's power plants. Furthermore, Tampa Electric strives daily to obtain reliable supplies of natural gas at favorable prices in order to mitigate costs to its customers. Additionally, Tampa Electric's risk management activities reduce natural gas price volatility.

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

A. Tampa Electric receives natural gas via the Florida Gas Transmission ("FGT") and Gulfstream Natural Gas System, LLC ("Gulfstream") pipelines. The ability to deliver natural gas directly from two pipelines increases the fuel delivery reliability for Bayside Power Station, which is composed of two large natural gas combined-cycle units and four aero-derivative combustion turbines. Natural gas can also be delivered to Big Bend Station directly from Gulfstream to support the aero-derivative combustion turbine and natural gas co-firing in the coal units. Polk Station receives natural gas from FGT to support the four existing natural gas combustion turbines that are being converted to Polk Unit 2 CC and Polk Unit 1 as an alternate fuel.

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

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

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

Tampa Electric also reserves capacity on the Southeast Supply Header ("SESH") and the Transco lateral. SESH and the Transco lateral connect 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. Thus, SESH and the Transco lateral give Tampa Electric access to secure, competitively priced on-shore gas supply for a portion of its portfolio.

Q. Does Tampa Electric have plans to secure additional natural gas supply for 2017 delivery?

A. Yes. Tampa Electric is currently in the process of securing approximately 65 percent of the company's expected natural gas requirements for 2017. The balance of Tampa Electric's natural gas supply will be acquired through seasonal, monthly, and daily purchases to meet its varying operational needs.

Q. Will Tampa Electric need to enter additional supply or transportation contracts for natural gas once Polk Unit 2 CC is declared to be commercially in-service?

A. No, Tampa Electric does not expect to enter additional supply or transportation agreements for the natural gas to be used at Polk Station. Tampa Electric's portfolio approach to natural gas fuel supply and delivery allows it to absorb the new unit without significant changes to its contracts.

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

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

Projected 2016 Fuel Prices

Q. How does Tampa Electric project fuel prices?

A. Tampa Electric reviews fuel price forecasts from sources widely used in the industry, including the New York Mercantile Exchange ("NYMEX"), PIRA Energy, Wood Mackenzie, the Energy Information Administration, and other energy market information sources. Futures prices for energy commodities as traded on the NYMEX form the basis of the natural gas and No. 2 oil market commodity price forecasts. The commodity price projections are then adjusted to incorporate expected transportation costs and location differences. Tampa Electric utilized the average of the five daily NYMEX natural gas futures settlement prices for the period June 28, 2016 through July 5, 2016 to prepare the fuel price forecast.

Coal prices and coal transportation prices are projected using contracted pricing and information from industry-recognized consultants and published indices. Also, the price projections 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 2017 projected fuel prices compare to the fuel prices projected for 2016?

A. The commodity price for natural gas during 2017 is projected to be slightly higher than the prices projected for 2016. Reductions to natural gas production combined with increased gas-fired generation demand have put upward pressure on natural gas prices.

The 2017 coal commodity price projection is about the same as the price projected for 2016. Lower national coal demand resulting from coal-fired unit closures is expected to keep coal prices low despite consolidation and production cuts in domestic coal supply. However, in the long term these production cuts are expected to put upward pressure on coal prices.

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

A. Yes. While 2017 projected prices for coal and natural gas are expected to be relatively similar to 2016 prices, Tampa Electric recognizes that there is uncertainty in future prices. Therefore, Tampa Electric prepared a scenario in which the forecasted price for natural gas was increased by 40 percent. Similarly, Tampa Electric prepared a scenario in which the forecasted price for natural gas was reduced by 40 percent. Due to Tampa Electric's generating mix and Commission-approved natural gas hedging strategy, the impact of the fuel price changes under either scenario is mitigated.

Risk Management Activities

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

A. Tampa Electric complies with its risk management plan as approved by the company's Risk Authorizing Committee. Tampa

Electric's plan is described in detail in the Fuel Procurement and Wholesale Power Purchases Risk Management Plan ("Risk Management Plan"), submitted to the Commission on August 4, 2016 in this docket.

Q. Has Tampa Electric used financial hedging in an effort to mitigate the price volatility of its 2016 and 2017 natural gas requirements?

A. Yes. As a part of its Risk Management Plan, Tampa Electric hedged a significant portion of its 2016 natural gas supply needs and a portion of its expected 2017 natural gas supply needs in accordance with the company's hedge plan. Tampa Electric will continue to take advantage of available natural gas hedging opportunities in an effort to benefit its customers, while complying with its approved Risk Management Plan. The current market position for natural gas hedges was provided in the company's Natural Gas Hedging Activities report submitted to the Commission in this docket on August 18, 2016.

Q. Are the company's strategies adequate for mitigating price risk for Tampa Electric's 2016 and 2017 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 also described in detail in Tampa Electric's Risk Management Plan.

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

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

Q. Were Tampa Electric's efforts through July 31, 2016 to mitigate price volatility through its non-speculative hedging program prudent?

A. Yes. Tampa Electric has executed hedges according to the Risk Management Plan approved by the company's Risk Authorizing Committee and filed with this Commission. On April 6, 2016, the company filed its 2015 Natural Gas Hedging Activities report. Additionally, utilities must submit a Natural Gas Hedging Activity Report showing the results of hedging activities from January through July of the current year. The Hedging Activity 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 Natural Gas Hedging Activities report, showing the results of its prudent hedging activities from January through July 2016, in this docket on August 18, 2016.

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

A. Tampa Electric's hedged quantity of natural gas may or may not generate fuel savings. Fuel savings is not the focus of the hedge program. The primary objective of the company's hedging program is to reduce fuel price volatility as approved by the Commission, not speculate on the price of fuel. Tampa Electric's hedging program requires consistent hedging based on expected needs. The company does not engage in speculative hedging strategies aimed at out-guessing the market. This discipline ensures the needed hedge volumes will be in place for customers regardless of the price movements of natural gas.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF SIMON O. OJADA

DOCKET NO. 160001-EI

September 23, 2016

Q. Please state your name and business address.

A. My name is Simon O. Ojada. My business address is 1313 N. Tampa Street, Suite 220, Tampa, Florida 33602.

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

A. I am employed by the Florida Public Service Commission (FPSC or Commission) as a Public Utility Analyst in the Office of Auditing and Performance Analysis. I have been employed by the Commission since April 1997.

Q. Briefly review your educational and professional background.

A. I received a Bachelor of Science degree from the University of South Florida with a major in Finance in 1991, a Bachelor of Science Degree from Florida Metropolitan University with a major in Accounting in 1994, and a Master of Business Administration with a concentration in Accounting in 1997.

Q. Please describe your current responsibilities.

A. My responsibilities consist of planning and conducting utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you previously presented testimony before this Commission?

A. Yes. I filed testimony in the Fuel and Purchased Power Cost Recovery Clause, Docket Nos. 130001-EI, 140001-EI, and 150001-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Duke Energy Florida, LLC (DEF or Utility) which addresses the Utility's filing in Docket No. 160001-EI, Fuel and Purchased Power Cost Recovery Clause, for costs associated with its hedging activities. We issued an audit report in this docket for the hedging activities on September 16, 2016. This audit report is filed with my testimony and is identified as Exhibit (SOO-1).

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

A. Yes, it was prepared under my direction.

Q. Please describe the work performed in this audit.

A. I have separated the audit work into several categories.

Accounting Treatment

I reviewed DEF's supporting detail of the hedging settlements for the twelve months ended July 31, 2016. I verified the monthly balances of hedging transactions from DEF's Hedging Details Report for the period August 1, 2015 to July 31, 2016 to its Hedging Summary by Commodity Reports for 2015 and 2016 to the general ledger. No exceptions were noted.

Gains and Losses

I selected 20 natural gas hedging transactions from August 2015 through July 2016 as a sample. I reconciled the selected samples from the Hedging Details Reports to the third-party confirmation notices and contracts. I reconciled the gains and losses to the Utility's journal entries. I compared the price on the confirmation notice to the price published by the NYMEX Henry Hub gas futures contract rates. No exceptions were noted.

Hedged Volume and Limits

I obtained and reviewed DEF's Risk Management Plan**.** I reviewed the quantity limits and authorizations for all hedged fuel types. No exceptions were noted.

Separation of Duties

I reviewed DEF's written procedures for separation of duties related to hedging activities. There were no internal or external audits related to hedging activities. No exceptions were noted.

Q. Please review the audit findings in this audit report.

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

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF INTESAR TERKAWI

DOCKET NO. 160001-EI

September 23, 2016

Q. Please state your name and business address.

A. My name is Intesar Terkawi. My business address is 1313 N. Tampa Street, Suite 220, Tampa, Florida 33602.

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

A. I am employed by the Florida Public Service Commission (FPSC or Commission) as a Public Utility Analyst in the Office of Auditing and Performance Analysis. I have been employed by the Commission since October 2001.

Q. Briefly review your educational and professional background.

A. In 1995, I received a Master Degree of Arts with a major in Communications from the University of Central Florida. In 2001, I received a Bachelor of Science Degree from the University of Central Florida with a major in accounting. I am also a Certified Public Accountant and an Enrolled Tax Agent.

Q. Please describe your current responsibilities.

A. My responsibilities consist of planning and conducting utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you previously presented testimony before this Commission?

A. Yes. I filed testimony in the Fuel and Purchased Power Cost Recovery Clause, Docket Nos. 140001-EI and 150001-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Tampa Electric Company (TECO or Utility) which addresses the Utility's filing in Docket No. 160001-EI, Fuel and Purchased Power Cost Recovery Clause, for costs associated with its hedging activities. We issued an audit report in this docket for the hedging activities on September 16, 2016. This audit report is filed with my testimony and is identified as Exhibit (IT-1).

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

A. Yes, it was prepared under my direction.

Q. Please describe the work performed in this audit.

A. I have separated the audit work into several categories.

Accounting Treatment

I reviewed TECO's supporting detail of the hedging settlements for the twelve months ended July 31, 2016. I traced the transactions to the general ledger and trade confirmation documents. I verified that the hedging settlements were in compliance with the Risk Management Plan and verified that the accounting treatment for hedging transactions and transactions costs are consistent with Commission orders relating to hedging activities. No exceptions were noted.

Gains and Losses

I traced the monthly balances of hedging transactions from TECO's Hedging Information Report to its Mark to Market Position Report for the period August 1, 2015, to July 31, 2016. I selected all gas hedging transactions for September and October 2015 and traced them from the Mark to Market Position Report to the third-party confirmation notices and contracts. I traced a sample of the purchase prices to the Gas Daily – NYMEX Henry Hub gas futures contract rates. I traced the related settlements prices to the Gas Daily – NYMEX Henry Hub gas futures contract rate. I recalculated the gains and losses and traced them to the Utility's journal entries for realized gains and losses. No exceptions were noted.

Hedged Volume and Limits

I reviewed the quantity limits and authorizations. I also obtained TECO's analysis of the monthly percent of fuel hedged in relation to fuel burned for the twelve months ended July 31, 2016, and compared them with the Utility's Risk Management Plan. There were variances for 11 of the 12 months between the percentages of actual and projected natural gas burned that were hedged. No further work was done.

Separation of Duties

I reviewed TECO's written procedures for separation of duties related to hedging activities. There were no internal or external audits related to hedging activities. No exceptions were noted.

Q. Please review the audit findings in this audit report.

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

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF MARISA N. GLOVER

DOCKET NO. 160001-EI

SEPTEMBER 23, 2016

Q. Please state your name and business address.

A. My name is Marisa Glover and my business address is 2540 Shumard Oak Boulevard, Tallahassee, FL 32399.

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

A. I am employed by the Florida Public Service Commission (FPSC or Commission) as a Regulatory Analyst Supervisor in the Office of Auditing and Performance Analysis.

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

A. I have been employed by the Commission since April 2016.

Q. Briefly review your educational and professional background.

A. I have a Bachelor of Science degree in Accounting from the Saint Leo University, and a Criminology degree from Florida State University.

Q. Please describe your current responsibilities.

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

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

A. No

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Florida Power & Light Company (FPL or Utility) which addresses the Utility's filing in Docket No. 160001-EI Fuel and Purchased Power Cost Recovery Clause for costs associated with its hedging activities. We issued an audit report in this docket for the hedging activities on August 19, 2016. This audit report is filed with my testimony and is identified as Exhibit MNG-1.

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

A. Yes, it was prepared under my direction.

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

A. I have separated the audit work into several categories.

<u>Accounting Treatment</u>

We obtained FPL's supporting detail of the hedging settlements for the twelve months ended July 31, 2016. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements were in compliance with the Risk Management Plan and verified that the accounting treatment for hedging transactions and transactions costs are consistent with Commission orders relating to hedging activities. No exceptions were noted.

<u>Gains and Losses</u>

We traced the monthly balances of hedging transactions from FPL's April 6, 2016 and August 18, 2016 filings in this docket for the period August 1, 2015 to July 31, 2016 to FPL's Derivative Settlement Report. We selected various hedging transactions from various counterparties from November 2015 and March 2016 for natural gas as a sample and traced them from the Derivative Settlement Report to the invoices, purchase statements, confirmation notices and deal tickets. FPL does not have any tolling agreements where natural gas is provided to generators under purchase power agreements. We recalculated the gains and losses. We compared these recalculated gains and losses with FPL's journal entries for realized gains and losses. We compared a sample of the purchase prices to the futures rates published by the NYMEX Henry Hub gas futures contract rates. We traced a sample of settlement prices to the futures rates published by the NYMEX Henry Hub gas futures contract rates. No exceptions were noted.

<u>Hedged Volume and Limits</u>

We reviewed the quantity limits and authorizations. We also obtained FPL's analysis of the monthly percent of fuel hedged in relation to fuel burned for the twelve months ended July 31, 2016, and compared them with the Utility's Risk Management Plan. The hedged targets for natural gas were traced to the Planned Position Strategy Schedule. The fuel burn forecast was traced to the Fuel Burn Summary. No exceptions were noted.

<u>Separation of Duties</u>

We reviewed the Utility's procedures for separating duties related to hedging activities. We traced the names from deal tickets and confirmations to FPL's procedures and determined the physical location of various personnel. No exceptions were noted.

Q. Please review the audit findings in this audit report, Exhibit MNG-1.

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

Q. Does that conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF DONNA D. BROWN

DOCKET NO. 160001-EI

SEPTEMBER 23, 2016

Q. Please state your name and business address.

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

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

A. I am employed by the Florida Public Service Commission (FPSC or Commission) as a Public Utility Analyst II in the Office of Auditing and Performance Analysis. I have been employed by the Commission since February 2008.

Q. Briefly review your educational and professional background.

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

Q. Please describe your current responsibilities.

A. My responsibilities consist of planning and conducting utility audits of manual and automated accounting systems for historical and forecasted data.

Q. Have you previously presented testimony before this Commission?

A. Yes. I filed testimony in the Fuel and Purchased Power Cost Recovery Clause, Docket Nos. 110001-EI and 120001-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Gulf Power

Company (Gulf or Utility) which addresses the Utility's filing in Docket No. 160001-EI, Fuel and Purchased Power Cost Recovery Clause, for costs associated with its hedging activities. We issued an audit report in this docket for the hedging activities on September 15, 2016. This audit report is filed with my testimony and is identified as Exhibit (DDB-1).

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

A. Yes, it was prepared under my direction.

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

A. I have separated the audit work into several categories.

<u>Accounting Treatment</u>

We obtained Gulf's supporting detail of the hedging settlements for the twelve months ended July 31, 2016. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements are in compliance with the Risk Management Plan and verified that the accounting treatment for hedging transactions and transactions costs is consistent with Commission orders relating to hedging activities. No exceptions were noted.

<u>Gains and Losses</u>

We traced the monthly balances of all hedging transactions from Gulf's Hedging Information Reports to its settlement report and its general ledger for the period August 1, 2015 to July 31, 2016. We reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. We recalculated the gains and losses, traced the price to the settlement statement details, and compared the price to the gas futures rates published by the New York Mercantile Exchange (NYMEX) Henry Hub Gas futures contract rates. We compared these recalculated gains and losses with Gulf's journal entries for realized gains and losses. No exceptions were noted.

Hedged Volume and Limits

We reviewed the quantity limits and authorizations. We also obtained Gulf's analysis of the monthly percent of natural gas hedged in relation to natural gas burned for the twelve months ended July 31, 2016, and compared them with the Utility's Risk Management Plan. No exceptions were noted.

Separation of Duties

We reviewed the Utility's procedures for separating duties related to hedging activities. We also reviewed internal audit reports from August 1, 2015 to July 31, 2016 and noted one pertained to fuel hedging programs, issued July 12, 2016 with no reportable findings. No exceptions were noted.

Q. Please review the audit findings in this audit report.

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

Q. Does that conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 160001-EI DATED: OCTOBER 19, 2016

NOTICE OF FILING ERRATA CORRECTIONS

NOTICE is hereby given of the following corrections to the testimony of Michael A. Gettings filed on September 23, 2016:

Page 22, line 7	From 75% to 81%
Page 22, line 8	From 38% to 40%
Page 22, line 9	From 37% to 41%
Page 22, line 11	From 38% to 40%
Page 22, line 12	From 37% to 41%

RESPECTFULLY SUBMITTED, this 19th day of October, 2016:

/s/ Suzanne S. Brownless

SUZANNE S. BROWNLESS
Senior Attorney, Office of the General Counsel

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF MICHAEL A. GETTINGS

DOCKET NO. 160001-EI

SEPTEMBER 23, 2016

Q. Please state your name, and employment information.

A. My name is Michael A. Gettings and I am Senior Partner and owner of RiskCentrix, LLC. My address is 225 Good Hope Rd., Bluffton, SC.

Q. Please provide a brief summary of your qualifications, particularly as related to energy hedging practices.

A. I have a Bachelor's degree in Mechanical Engineering from Manhattan College (1971) and an MBA in Financial Management from Pace University (1977). I worked for Orange and Rockland Utilities ("O&R") as manager of economic studies in the regulatory area from approximately 1978 to 1982. Beginning in 1982, I ran O&R's non-regulated oil and gas production assets, and with the advent of FERC Order 436 in 1985, I founded their natural gas marketing and trading company, O&R Energy. As president of O&R Energy, I oversaw the adoption of hedging practices when NYMEX natural gas futures contracts began trading in 1991. Before leaving O&R in 1996, I effected the sale of a minority interest in O&R Energy to Shell Oil.

Beginning in 1996, I joined CC Pace, an energy consulting firm in Fairfax VA, and started an energy management practice there. Hedging strategy formulation, risk quantification systems, and hedge advisories quickly became the most significant offerings of that practice, and around the year 2000, the risk management group was a stand-alone division within the firm. For the last 17 years, I have advised utilities, large industrials, and independent generation companies on the formulation of economically efficient hedging programs. Since 2010, I have done so with my own firm - RiskCentrix, LLC. Most recently I have worked for the Washington State public utility commission and Attorney General's office writing a position paper and testifying at collaborative workshops to encourage more robust hedging practices among gas utilities there.

My resume which includes a description of experience, testimony and publications is attached as Exhibit ____ (MAG-1).

Q. Have you designed and run hedging programs for utilities?

A. Yes. I've designed energy risk mitigation programs and provided ongoing advisory services for numerous large public utilities in New York, California, and other states, as well as Canada. In numerous cases I sat as an ex officio member on the utilities' executive risk management committee. I've also done this for an investor-owned utility with provider-of-last-resort obligations, as well as others who simply wanted to upgrade from fixed-percentage hedge accumulations. Finally, I've designed programs for many industrial firms and sat on the executive risk management committee for one independent power producer.

Q. Please describe the nature of your testimony here?

A. My testimony presents a hedging framework for the Commission to consider as an alternative to the current hedging practices that Duke Energy Florida ("DEF"), Florida Power and Light ("FPL"), Gulf Power ("Gulf"), and Tampa Electric ("TECO") follow in procuring natural gas to fuel their generating plants. The core of my testimony will contrast the "targeted-volume" hedging methods currently deployed in Florida with a more robust "risk-responsive" approach that monitors risk and responds to emerging conditions in accordance with preplanned decision protocols. The risk-responsive approach has been supported by quantitative finance methods developed in the 1990's.

I will also describe the reasons for hedging and how to structure objectives in a well-conceived hedging program. I will explain in some detail the methods and advantages of a risk-responsive approach to hedging, and present simulation results that compare the economics of that approach to the targeted-volume hedge accumulation currently deployed by Florida utilities. Finally, I will offer opinions as to how regulatory policy might inhibit or could promote the adoption of better hedge programs.

Q. How is your testimony organized?

A. My testimony is organized in three parts. **Part I - Background** includes a limited discussion of the current hedging practices of DEF, FPL, Gulf, and TECO and a conceptual discussion as to why hedging is beneficial, the definition of key risk management concepts, and perspectives on market history, objective setting, and the shortcoming of fundamental predictions. **Part II - Strategy** provides more detail as to how hedge programs can be improved, including risk-responsive strategy elements, simulated results, and a discussion of the mechanics within a risk-responsive strategy. Finally, **Part III - Regulation** provides a discussion of the regulatory implications and how small changes in regulation could encourage beneficial change.

<u>Part I - Background</u>

Q. In this docket one issue has been whether or not to hedge at all. Do you have a view on this?

A. Yes I do. The purpose of hedging is to minimize customer pain associated with energy-price (or customer-cost) increases. That is different than simply reducing exposure to volatility because customers' sensitivity to pain is not symmetrical. This characteristic suggests hedging provides a benefit to customers.

Q. Please explain your point as to the customers' asymmetric pain.

A. The asymmetry is due to the fact that tolerance for upside cost exposure in rising markets is different than the tolerance for hedge losses in downward markets. Using a simple analogy for residential customers, taking a $500 better vacation with utility-bill savings would be a good thing and if utility hedge losses moderate those savings so that they are $300 rather than $500 it is still a good net outcome despite the $200 foregone savings. On the other hand, that same customer might struggle to meet necessary expenses if faced with an unmitigated $500 increase in utility costs, and that would be a very bad thing. Said differently, hedge losses occur in low-cost markets, so outcomes are still beneficial but less so; in low-cost markets customer impacts are constrained to discretionary choices regarding alternative uses of reduced savings. Cost increases occur in high-cost markets where unfavorable outcomes, if unmitigated, can be severe; also the customers' budget response is more likely to impact non-discretionary spending. So on balance, customers experience greater value from potential cost mitigation than they forego with potential hedge losses.

Q. Is there any other factor that would influence the customers' value realization?

A. Yes. Natural gas prices are lognormally distributed. That is, relative to the average price, upside outliers are much larger than downside outliers. To illustrate, historical price variations since the year 2000 indicate the average price of Henry Hub natural gas has been about $5.00 per MMBtu. Month-end prices have ranged from under $2.00 per MMBtu to about $15.00 per MMBtu. That is, three dollars lower than average, but ten dollars higher than average. Even using a twelve-month smoothing to reflect a proxy for fuel cost adjustments, smoothed prices ranged from over $9.00 to less than $3.00 per MMBtu; that is four dollars above average versus two dollars below. And price peaks tend to last about a year, while price troughs tend to last longer.

Q. Why does this matter?

A. It is self-evident that gas-related customer cost increases, which are double those of cost decreases when unhedged, would argue in favor of a mitigation program. A hedge program increases the probability of small cost changes and decreases the probability of large changes; customers can absorb small cost changes with disproportionate ease, while large changes can be disproportionately painful.

Q. Have you reviewed the 2017 risk management plans filed by the four Florida Utilities?

A. Yes. The plans cover numerous risk elements as well as governance and management controls.

Q. What observations can you offer regarding those plans and please explain how your observations inform the rest of your testimony?

A. My scope here will deal only with the prospective economic performance of the 2017 Risk Management plans, and how the plans could be improved. I will focus on the core structure of those plans rather than specifics due to confidentiality constraints regarding the detailed risk management plans ("2017 RMPs"). Generally all of the utilities propose to accumulate hedges in accordance with a predetermined timeline using a targeted-volume approach. Some discretion is contemplated, but none of the 2017 RMPs seem to measure the risk being managed in a quantitative fashion. The target hedge ratios specified in the 2017 RMPs are sometimes lower than prior targets. I find this concerning, but when limited to a calendar-based hedge program it is a typical reaction to increased scrutiny following significant hedge losses like those of recent years. I will discuss this concern, but more importantly, I will explain how comparable cost mitigation can be accomplished while better managing the risk of hedge losses. In Part II of my testimony, I will propose an alternative approach to hedging utilizing more robust quantitative tools deployed in a risk-responsive fashion.

Q. Would you agree with the goals expressed in the 2017 RMPs?

A. Only in a colloquial sense, but more precision would be very helpful. In all cases the RMP goals are stated as net volatility reduction or some semantic variation of it; some speak of volatility and risk, implying a valid distinction between the two which was never developed in the plans. I think it is important to distinguish volatility from the two-sided risk that derives from volatility, so I will deal with that in my testimony. None of the plans state that they will explicitly measure and manage the upside cost risk for customers, but curiously, the risk management control documents included in the 2017 RMPs do seem to measure the value at risk associated with executed hedge positions. It is self-evident that the primary reason for hedging is to mitigate upside cost exposures, and the potential for hedge losses is an associated consequence which needs to be managed as well. The cost mitigation is primary and the loss potential is possible collateral damage, but the 2017 RMPs only seem to measure the latter. In fact, it was not clear that the risk of loss is being viewed from the customers' perspective; it seemed to focus only on the exposures of trading positions.

At least one company specifies that, its "strategy primarily attempts to enter into hedges on downward gas movements;" yet they assert that they do not attempt to "beat the market." I struggled to reconcile those two assertions, but I will address the issue by discussing the difference between hedging driven by a risk view versus a market view.

Q. Earlier you referred to more robust quantitative tools. What sort of tools do you mean, and would this represent a new skill set for the utilities?

A. I'll explain in some detail, but the most useful of these tools permit the measurement of volatility and the assessment of associated risks, and I believe the companies generally possess capabilities to do so, although the deployment of those tools is not focused on cost mitigation. The governance and controls documents included with the 2017 RMPs generally refer to value-at-risk metrics. Value at Risk (VaR) is a term of art in the field of quantitative finance.

It is a very important concept for managing trading risk or commodity-cost risk. In the governance and controls documents of the 2017 RMPs, VaR is used to control trading risk, but it is never referenced as a driver of a hedge program. I will spend some time discussing its application to natural gas hedging on behalf of customers.

Q. Would you characterize the structure of these plans as typical among utilities in the USA?

A. To answer fairly I will divide the utility industry into segments. There is the regulated investor-owned utility segment which most often deploys targeted-volume hedge accumulation programs like those reflected in the 2017 RMPs. There is the public-power segment which has been far more prone to use risk-responsive programs based on quantitative-finance tools. Finally there is the non-regulated segment consisting of independent power generators and utility affiliates that trade or produce energy for profit, and they too are more prone to use risk-responsive programs.

So, while calendar-based, targeted-volume hedge accumulation is typical of regulated investor-owned utilities, utilities with a different regulatory structure often adopt more sophisticated methods; so do affiliated unregulated operations.

Q. Please explain in more detail what you mean by a risk-responsive hedge program.

A. I will describe more specifics later, but stated simply, risk exposures can be assessed by measuring transient price volatility and the related VaR. Methods to do so were published by a JP Morgan affiliate more than twenty-five years ago. Many companies, including Florida utilities, understand the mathematics of VaR but they often use it to measure risk of credit exposures or as a control on trader activities. The same mathematics can be applied to customers' risk of cost increases or hedge loss potential. A customer-focused, risk-responsive hedge program would establish tolerances for cost increases and separate tolerances for hedge losses, and then formulate a strategy of prescribed responses to defend those tolerances against whatever risk conditions might emerge. In other words, rather than accumulate hedges according to the calendar regardless of how prices and risks might change, risk-responsive programs serve to measure and respond to risk conditions on behalf of customers.

Q. You talk of price volatility as a transient, measurable metric which does not seem to be factored explicitly into the utilities' plans. Can you explain?

A. Yes. Beyond its colloquial meaning, volatility is a term of art in the discipline of financial hedging. It has a very specific meaning. "Observed volatility" is the potential percentage movement in future prices at a specified confidence level over a specified timeframe. For natural gas, when one hears a standardized expression of volatility, it typically refers to the potential for price movements of a specific futures contract or group of contracts over one year at one standard deviation. To illustrate, if the November-2016 NYMEX contract for natural gas exhibited a 30% volatility, that would mean one could be 83% confident that the price of that contract will not increase by more than an indicative 30% in a year. Note that I say indicative because a more precise measure of variability would be asymmetrical, reflecting the lognormal probability distribution (upward magnitude greater than downward), but the single volatility number represents an indicative estimation.

Q. You also referred to value at risk or VaR; how does that relate to volatility and risk?

A. Volatility is a non-directional concept of price variability. Value at Risk is a tangible measurement of volatility-related financial risk; it is directional and it is actionable. VaR can measure cost-increase risks in potential upside markets as well as hedge-loss risk in potential downside markets. These measurements can then serve as the basis for risk-responsive hedging decisions.

Q. Would you elaborate?

A. In hedging, it is useful to articulate cost tolerances for upside markets as well as hedge-loss tolerance for downside markets, and to make risk assessments to determine if those tolerances are at risk of being breached. Hedge decisions can then be guided by those metrics. To facilitate decisions, a useful risk assessment should reflect exposures in aggregate dollar values as well as value per unit; it should consider hedged versus unhedged volumes, the hedger's reasonable response time, and how confidently one would like to prevent painful outcomes. Importantly, it should reflect the asymmetrical risk of price movements; VaR is the metric that does all this. "Cost VaR" measures upward cost risk, while mark-to-market VaR, or "MtM VaR" measures incremental hedge loss potential. Finally, since VaR reflects the incremental risk, the potential for unfavorable outcomes can be calculated by adding VaR to the current position. So a "Cost Outlier" would equal the current forward portfolio cost plus Cost VaR, and the "MtM Outlier" would equal the current forward MtM plus MtM VaR. VaR metrics and the associated outliers measure potential outcomes before they materialize. The lead time is called a "holding period."

The holding period can be set at the discretion of the hedge manager; it should provide reasonable time to execute hedge decisions, but not so long as to render the risk unmanageable. A trading company typically uses a 1-day VaR, but in managing customer costs where the time to execute hedges is longer, something like a 10 or 20-day holding period is more appropriate, but certainly not a full year. And typically metrics would be assessed at some higher confidence than one standard deviation because hedge managers look for higher confidence in acceptable outcomes.

Q. How does this relate to the utilities' objective of reducing volatility?

A. The risk management plans indicate that generally Florida utilities maintain volatility curves and some VaR metrics for control functions, but not to track a customer-cost perspective. A hedge program that accumulates hedge positions in accordance with a calendar schedule pays little attention to these risk metrics because the metrics do not drive hedge responses. Yet the utilities' capability to measure VaR exists or is within easy reach. I believe the phrase "reducing volatility" is being used colloquially in these plans. If volatility were used in a quantitatively disciplined fashion, the assertion of volatility reduction would be far from certain with a targeted-volume hedge ratio.

To illustrate, in early 2008 one-year-forward natural gas market prices exhibited a 25% approximate volatility. A hedge planner who targeted a 50% hedge ratio might have expected a net volatility reduction to 12.5%, but it would not have worked. A year later, market volatility had risen to about 50%, and having attained the 50% hedge ratio the net exposure to prevailing volatility would have been unchanged at 25%. The colloquially stated objective would have led to a measureable risk profile that was unchanged because quantitative discipline was never imposed and the hedge plan did not provide for transient measurements and responses.

The hedge ratio is the tool and the two objectives are tolerable costs and tolerable hedge losses. A fixed target volume of hedges without consideration of the risk conditions permits intolerable outcomes. Florida's principle hedging issue in recent years has been that, following the 2008 price peak, hedging a fixed percentage without consideration of the risk conditions allowed losses to accumulate without a plan for responsive adjustments.

Gas market volatility is like the weather; it is constantly changing. By way of analogy, in Florida and everywhere, air conditioners are not set to target a 50% run rate; they target a temperature. A thermostat measures the temperature and responds by increasing or decreasing the compressor runtime. If a 50% runtime were targeted, the results would be too hot on hot days and too cold on cold days. The objective is comfort on both hot and cold days, and the compressor is the tool, just as tolerable costs and tolerable hedge losses are the objectives and the hedge ratio is the tool.

Q. What conclusion would you draw from this illustration?

A. If the results are important, and clearly they are, a colloquial treatment of volatility will not accomplish fully articulated hedge objectives, and targeting a hedge ratio, which is only a tool, is inferior to targeting explicitly tolerable results. Quantitative discipline is a critical component in attaining tolerable outcomes.

Q. Are there other reasons to impose quantitative discipline?

A. Yes, at least two others. Human nature can be insidious when hedging ignores transient quantitative risk metrics, and a quantitative discipline facilitates better targeted objectives.

Q. Please explain your comment on human nature.

A. This goes to my concern with the current trend of hedge ratio reductions. Without a quantitative framework, it is a common response to increase hedge ratios when recent high-price fears have escalated, and to decrease hedge ratios after those fears subside. When annual plans determine target hedge ratios preemptively, and these metrics are not monitored, the focus is typically on prices; fearful sentiments tend to follow price events, so hedge ratios will often increase when prices are already peaking. Placid sentiments follow price troughs so hedge ratios often decrease when prices have already declined. The result is often self-defeating - to hedge more at higher prices and hedge less at lower prices. Under a regulated environment, where prudency issues are an issue, this instinct could be heightened. Once losses have accumulated, the instinct to curtail future losses can become dominant. Recently gas prices have been in a trough, so I would consider that the current trend of reducing hedge ratios might be driven by these instincts.

On the other hand, when the hedge manager is focused on volatility and value at risk, hedge responses substantially anticipate price events because VaR measures the potential for price changes before they happen.

Q. Could you put this concern into the context of historical price experience?

A. Yes. Since 2000, there have been two major spikes in natural gas prices; the first was related to hurricane Katrina in 2005 and the second coincided with the financial crisis of 2008.

Table 1 shows the magnitude of those spikes in green. In each case conventional wisdom during the price peak held that natural gas prices would continue at higher than historical prices. Consider the EIA forecasts published at the tail end of the 2008 price spike. Table 2 shows the EIA base case forecast (left) and four sensitivity cases (right) published in March of 2009 after the price peak had largely subsided.

Table 1: Natural Gas Futures Settlements 2002 to 2011

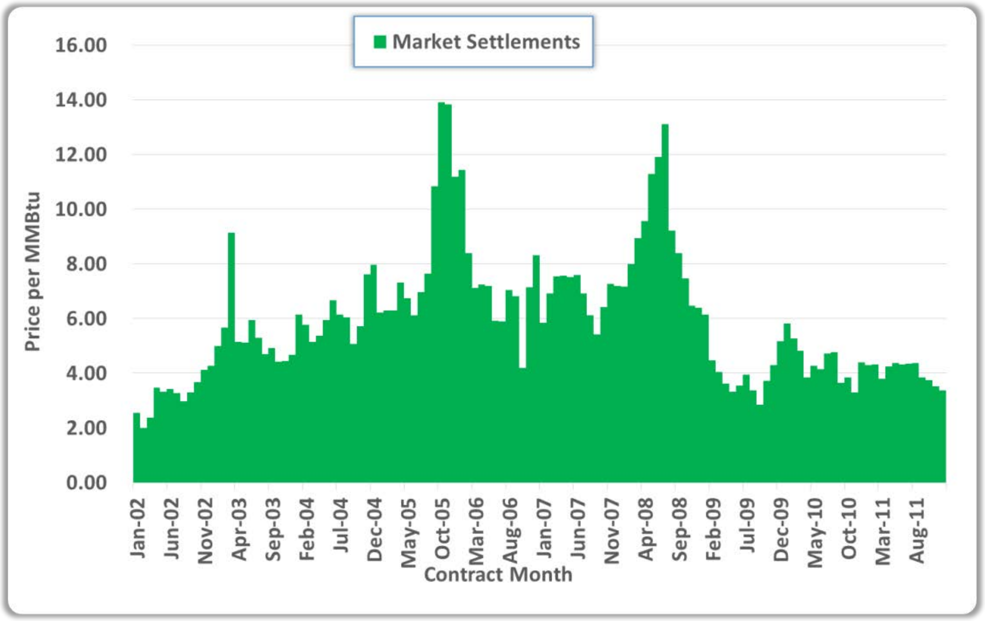


Table 2: EIA 2009 Natural Gas Forecasts

2009 EIA Annual Energy Outlook, March 2009

Figure 69. Lower 48 wellhead prices for natural gas in two cases, 1990-2030 (2007 dollars per thousand cubic feet)

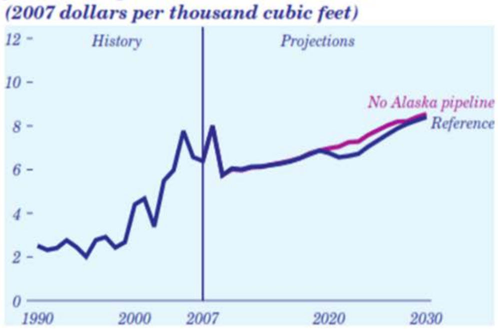
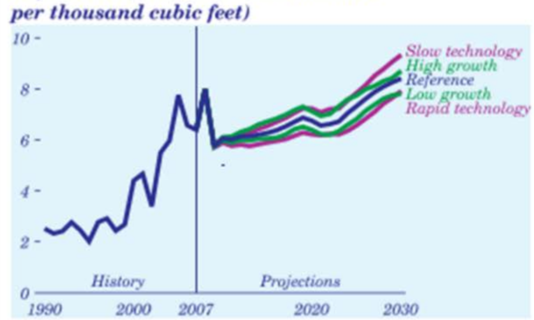


Figure 65. Lower 48 wellhead natural gas prices in five cases, 1990-2030 (2007 dollars per thousand cubic feet)



http://www.eia.gov/forecasts/archive/aeo09/pdf/0383(2009).pdf

Note how, in every EIA scenario, prices were expected to continue at elevated levels compared to historical norms. EIA forecasts are steeped in fundamental analysis. The 2009 Energy Outlook, which covers numerous energy commodities, is 221 pages of facts and projections regarding consumption, production, storage, legislation, regulation, technological evolution, cross-commodity effects, etc. But fundamental confidence in the future is an illusion. Such projections promote a false sense of confidence because our basic instincts find cause-and-effect narratives unrealistically attractive when thinking about the future. On the other hand, from a quantitative finance perspective, the prompt month price was about $4.00 and prompt month volatility was about 50%, so the 95% confidence range of potential price outcomes over one full year would have been between $1.50 and $10.65. When viewed objectively, the amount of uncertainty is very large, but it can be quantified, and when measured in smaller time increments, it can be managed.

Q. How does a quantitative perspective facilitate better objective setting?

A. Earlier I described how a colloquial view of volatility could result unexpectedly in a net risk position that is no better than the risk posture at the time the strategy was planned, but that only illustrates a symptom. More to the point, when reviewing results of a hedge strategy, the focus is always on two factors: cost increases in upside markets and hedge losses in downside markets. Even when a simple volatility reduction is invoked as the objective, stakeholders will ultimately judge success or failure by those two issues – how much did it mitigate costs or how large were hedge losses. Reinforcing the earlier distinction between tools and objectives, stakeholders will almost never judge success or failure of the hedge program based on whether or not the target hedge ratio was attained; stakeholders instinctively know the difference between the tool (hedge ratio) and the results (tolerable or intolerable outcomes). So the real objectives are two-fold; tolerances should reflect cost limits and hedge loss limits, and objectives should be established to promote results within acceptable dual tolerances. This can only be done using quantitative methods.

Q. Given what you describe, would you view the utilities' calendar-based hedging programs as imprudent?

A. No. In my experience, the vast majority of investor-owned utilities deploy programs of this nature. Without a stated regulatory policy having established higher standards, it would be unreasonable to label such a common practice as imprudent. Yet there is room for substantial improvement.

<u>Part II - Strategy</u>

Q. Please explain how you would structure improvements to a typical hedge program.

A. I would rely on defensive hedges primarily; I'll describe defensive hedge protocols in some detail later. I would use programmatic, or calendar-based hedges, only if the unmitigated risk profile would unduly strain the defensive hedge protocols. Finally I would plan contingent strategies for those rare times when hedge loss potential threatens the hedge-loss tolerance.

Q. Please explain the terms you used in that answer.

A. Hedge strategies consist of a basket of hedge decision rules, and hedge decisions can be categorized in four types: programmatic, defensive, contingent and discretionary. Programmatic hedges are executed based on the calendar regardless of prevailing risk conditions; chronologically they are usually the first executed, but in a well-designed program their importance is dwarfed by the defensive hedge protocols. Defensive hedge protocols monitor cost risk (Cost Outliers described earlier) and execute additional hedges only when risk conditions threaten some tolerance level. To the extent programmatic hedge volumes can be reduced and replaced with defensive protocols, customers can gain greater participation in declining cost markets. Contingent strategies monitor hedge-loss risk (MtM Outliers described earlier) and stand ready to respond to any threatened breach of hedge-loss tolerance by suspending new hedges, using options to constrain hedge loss potential, or unwinding hedges when necessary. A robust program preplans these three hedge responses which together constitute a comprehensive hedge strategy. Finally, some programs make limited use of discretionary hedges – buying hedges when the price is deemed attractive.

Q. While you defined four hedge decision categories, you seemed to deemphasize discretionary hedges in your response. Would you explain why?

A. Yes, a risk management program should measure and manage risk; hedges should be executed based on a "risk view" not a "market view." Responsive risk management strategies do not rely on the prediction of market movements; they rely on measuring and monitoring prevailing risk conditions, so the more precise designation used here is "risk-responsive" programs. A hedge program works most reliably when risk is measured daily or weekly and prospective hedge decisions are pre-planned for risk conditions that might emerge.

Further, the ability to win at market timing is usually illusory. Hedges are placed at futures market prices which reflect all participants' money-backed consensus as to the future price of natural gas. For the purpose of making hedge decisions, it is meaningless to hold a view that the price of gas is likely to rise (or fall) because of today's known fundamental factors. The futures price already reflects a consensus on what those factors mean for the future price of gas, and hedges can only be placed at those prices. All market participants have access to data regarding consumption, production, storage and other factors, and they have reached a consensus on next year's futures price. A given manager might do better or worse than a random guess at market timing, but if that represented a reliable skill, that manager would not be working for a salary. Having said that, a small constrained volume of discretionary hedges does little harm as long as hedge-loss risk is considered and monitored. I will ignore discretionary hedges for the rest of my direct testimony.

Q. Would you explain Defensive Hedge Protocols further?

A. Yes. First, let me state an obvious but important tenet: if no hedges are ever executed, no losses will be incurred, so if practical, the preference would be to hedge only when necessary. That is the nature of defensive hedge protocols. When risk metrics indicate that a defensible cost threshold might be breached over the holding period, hedges would be placed in proportion to the value at risk that must be eliminated – no more often and in no greater quantity. To avoid precipitous hedge accumulation, it is advisable to set interim action boundaries to be defended; the final action boundary would be equal to the ultimate cost tolerance. This might be more easily understood by using graphics to facilitate further discussion.

Table 3: Illustration of Value at Risk as Applied to a Natural Gas Portfolio

Table 3 illustrates the portfolio's Value at Risk for cost increases as the dotted line over a 10-day holding period. For ease of reference I have called VaR related to cost increases "Cost VaR" and the 2-sigma potential after 10 days, the "Cost Outlier." The portfolio costs and outliers would typically be different from analogous market values because of prior hedges.

Table 4: Comparing Portfolio Risk to a Cost Tolerance or Defensive Action Boundary

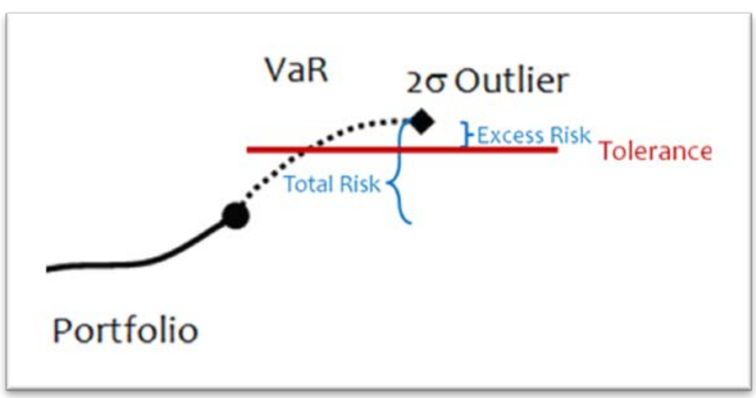


Table 4 illustrates how the Cost Outlier can be compared to a cost tolerance. Note that at any point, if hedges are executed they would be placed at prevailing market values consistent with the then-current portfolio cost; in other words, hedges will not be placed at the higher values burdened by the Cost VaR increment. The total risk reflects price exposure associated with the unhedged portion of the portfolio, so if the hedge manager desired to eliminate the encroachment, he or she would add a volume of hedges in accordance with the formula:

Hedge Increment (%) = Unhedged Ratio (%) x Excess VaR ($)/Total VaR ($)

A hedge of that magnitude would bring the post-hedge 2-sigma outlier down to the action boundary. Using illustrative numbers for clarity, if the portfolio were 40% hedged and 60% unhedged, and the Excess Risk was 5% of the Total Risk, then a 3% hedge increment would constrain the Cost Outlier to the Tolerance (5% times 60%). When the program monitors risk in weekly time spans a 3% hedge increment would be typical of occasional responses; many weeks would call for no hedge increments at all.

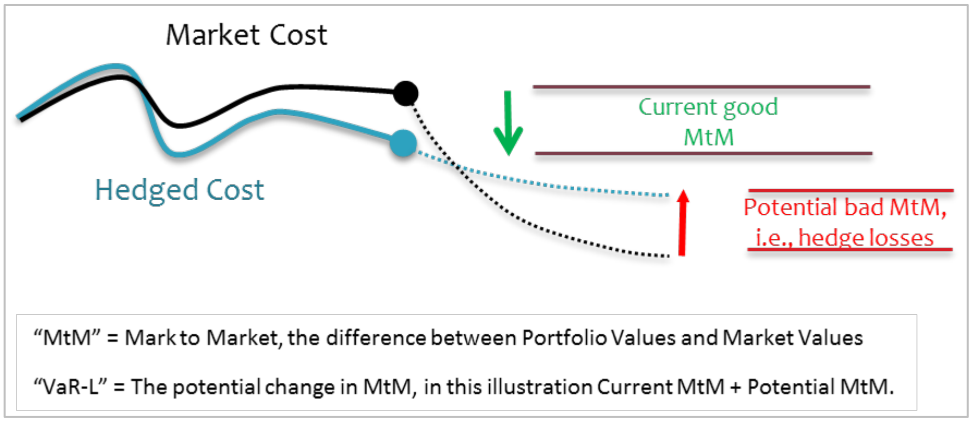
Q. Would you elaborate on the interim defensive action boundaries you referenced?

A. Yes. Natural gas volatility is typically high, so defensive hedge requirements might be precipitously large at times unless the ultimate cost tolerance is defended by interim tiered cost boundaries. Since these tiers are by definition at lower cost thresholds than the ultimate tolerance, I have called them “action boundaries.” Tiered action boundaries work this way: hedge as necessary in defense of boundary #1 up to a 30% hedge ratio (illustrative), then shift to defense of boundary #2 up to a 50% hedge ratio, etc. In this way the hedge manager is not waiting for the potential breach of an ultimate tolerance to hedge all needs in a precipitous manner.

Q. Would you explain what a Contingent Strategy might look like?

A. Yes. Recall that the contingent strategy is triggered when quantitative metrics indicate the risk of hedge losses is a serious concern, so first I will describe those metrics. Table 5 illustrates how hedge losses might accumulate in a market decline because the market price will fall more quickly than the hedged portfolio cost.

Table 5: Potential Hedge Loss Metrics



In the particular case illustrated, the portfolio begins with a favorable cost relative to market ("MtM"), but given the difference between potential downside market movements and downside portfolio movements there is a risk that favorable MtM could turn to hedge losses. To define terms analogous to the upside risk, MtM VaR would be the change in MtM in a downside market, and MtM Outlier would be the potential 2-sigma hedge loss. Both metrics refer to a holding period which might be 10 days, but if the firm's appetite is more averse to hedge losses a 90-day holding period could provide earlier warnings and more response time to adjust hedges.

Just as the defensive protocols defend against intolerable costs, a contingent strategy can be devised to defend against intolerable hedge losses. Since the year 2000, contingent strategies have rarely been necessary, most notably in the market environment following the 2008 price peak. At that time, when prices began collapsing, favorable MtMs, which accrued in the peak, provided an initial cushion. But later, as the favorable MtM faded, pre-planned contingent strategies were helpful in avoiding large losses.

Q. If defensive hedge rules require the establishment of cost tolerances, and contingent strategies require hedge-loss tolerances, how would you determine reasonable dual tolerances?

A. First let me explain some market considerations. Rational choices for cost tolerances and hedge-loss tolerances need to be paired in market-feasible sets. Tolerances are only rational if a strategy can attain them. In other words, for a given strategy a very tight cost tolerance must allow for greater hedge-loss tolerance and vice versa. Also market volatility plays a role. In high-volatility markets both tolerances must be wider to be attainable. Finally, the hedge strategy will play a big role in what can be accomplished. Tolerance pairs can be established by simulating hedge strategies against forward price curves for volatile periods, and then choosing the pairing that fits the firms risk appetite. I have done some simulations for the period from 2002 through 2011 to illustrate how improvements to goal setting and hedge strategy could be implemented.

Q. Why 2002 to 2011?

A. I chose those years because they include two major price cycles, and by 2011 the forward price curve and settlement prices had reached equilibrium.

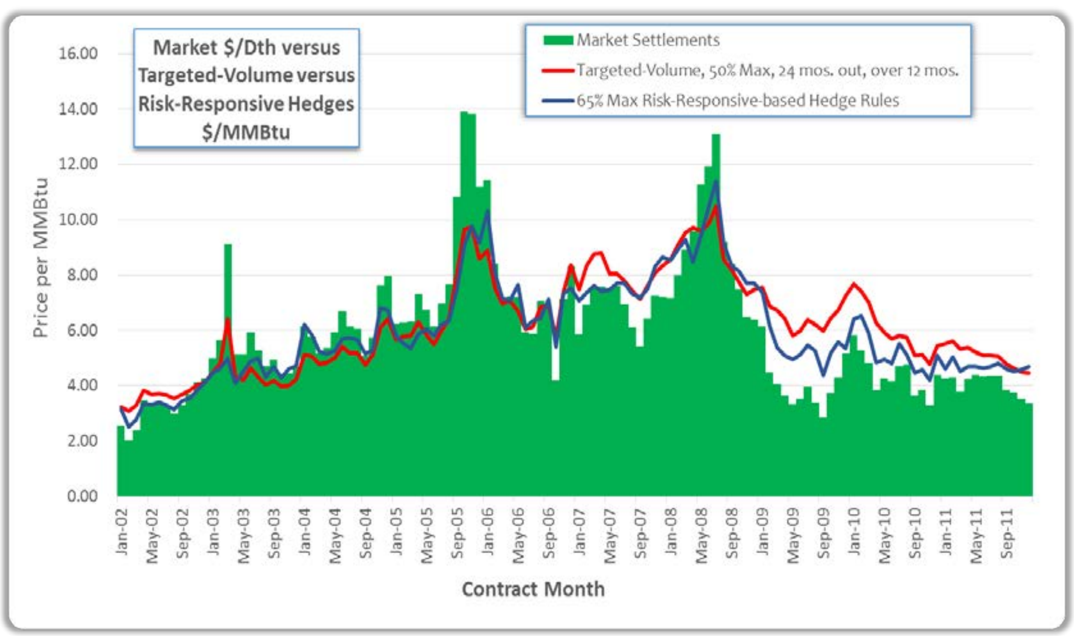
Q. Would you describe the simulations?

A. Yes. I simulated two strategy structures to show comparisons; the first was a targeted-volume strategy, much like those used in Florida to date, beginning 24 months prior to delivery. The second was a risk-responsive set of decision rules emphasizing defensive hedge responses to weekly risk measurements as well as contingent rules that either suspend hedges or unwind them when hedge-loss risk approaches tolerances. In the event of a conflict between defensive and contingent rules, the contingent rules dominated. For the targeted-volume structure, I tested numerous maximum hedge ratios. My objective was to assess worst-case pairings of rolling year-over-year cost increases and rolling 12-month hedge losses. To put the hedge-loss in context, I expressed that metric as a percent of average-year costs. This avoided the distortion which could have been created had hedge losses been expressed as a percent of severely depressed transient costs.

Q. What were the results of those simulations?

A. The graph in Table 6 shows monthly cost outcomes for both structures where targeted-volume hedges reached a maximum 50% hedge ratio and risk-responsive rules were permitted up to a maximum 65% of illustrative generic summer-peaking gas needs. The graph indicates substantially improved participation in the post 2008 downturn of market prices for the risk-responsive hedge rules. For reference, the largest year-over-year cost increase at market prices was about 75%, and obviously no hedge losses would have been incurred at market values. The targeted-volume approach produced a worst-case 38% cost increase and a worst-case 43% hedge loss. The risk-responsive program produced a 37% worst-case cost increase and a worst-case 22% hedge loss as a percent of average-year costs. Expressed as paired "tolerances" for cost increases and hedge losses, targeted volume rules were {38%, 43%} and risk-responsive rules were {37%, 22%}. In other words, the risk-responsive approach produced the same cost mitigation in high-cost periods, while incurring about one-half the hedge losses in the worst market downturns.

Table 6: Monthly Simulation Comparisons



Q. So, would you assert that these programs result in net savings versus market?

A. No. While comparative results have been very favorable compared to targeted volumes and the simulations illustrate this, the goal is not to "beat the market" and it would be inconsistent to assert that these programs do so. In fact, the simulation results indicate that even the risk-responsive hedges were very slightly higher than market costs. The goals are to ensure high confidence as to tolerable outcomes for customer cost increases as well as hedge losses. In other words, regardless of the price turmoil, accept that costs will track the average while ensuring that aberrations in costs and hedge losses conform to the desired risk appetite. In my experience, supported by the simulation results, risk-responsive programs accomplish exactly that. Those are the objectives, and risk-responsive hedging provides a large improvement over market outcomes or targeted-volume programs.

Q. You stated that you tested numerous maximum hedge ratios, what did those results indicate?

A. Table 7 is a plot of the tolerance pairs for various maximum hedge ratios under the targeted-volume structures compared to the risk-responsive strategy. It shows worst-case annual-cost changes increasing from left to right, and worst-over-period annual-loss outcomes increasing from top to bottom. Note that the targeted-volume pairings fall approximately on a diagonal line. This represents the range of choices available at various target hedge ratios under the generic representation of current Florida hedge programs. The blue dots represent the tolerance pairings available under an alternative risk-responsive structure. Only the maximum hedge ratio was varied to show a few blue dots. It should be noted that the risk-responsive structure can be adjusted in numerous ways and the structure shown is not particularly complex; for example, it uses no options. But the blue dots fall to the upside and left of the diagonal line. In other words it is superior as to cost containment and hedge loss containment. Had more strategies been evaluated, an efficient frontier could have been constructed; that is, a line defining superior outcomes so that any tolerance pairing downward and rightward would have inferior merit.

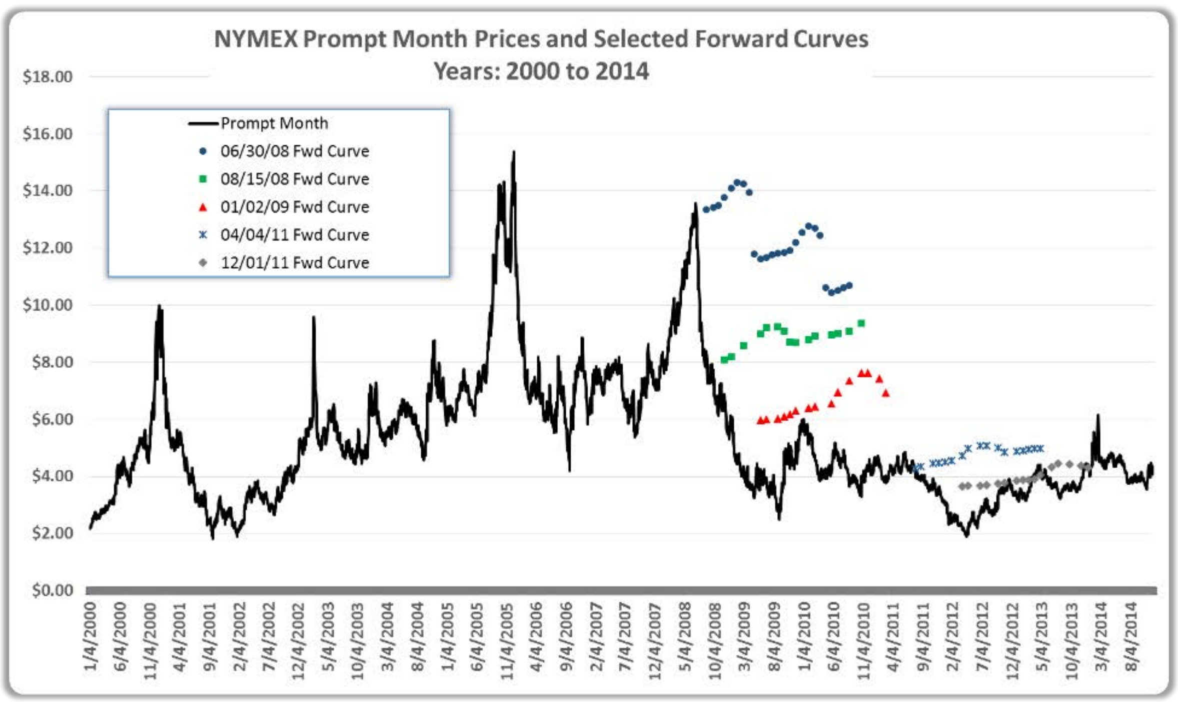
Table 7: Simulated Tolerance Pairs

Q. Given your testimony so far, how would you explain the multi-billion dollar losses experienced in Florida?

A. Calendar-based hedging, or what I have called targeted-volume hedging, exercises no quantitative risk monitoring in deciding to execute hedges. In theory, for a very large sample over a thousand years, if the program used a fixed-hedge ratio, average hedged costs should be about equal to market costs, but over a small history of five years there is no such comfort. Also, as described earlier, human nature can be insidious and hedge ratios rarely stay fixed over the long term.

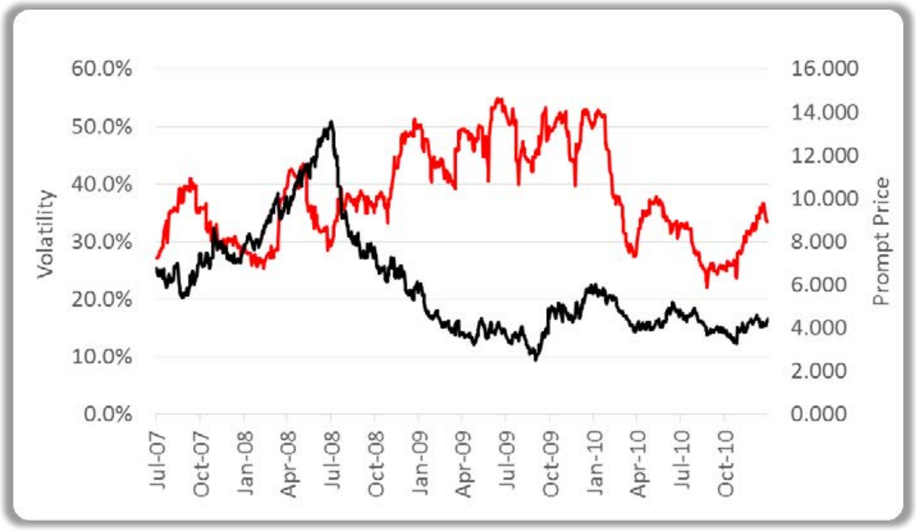
Table 8 will help highlight the small-history problem. Table 8 shows the prompt month price trends from 2000 through 2014 as a black continuous line. The prompt month is the nearest futures contract and it closely resembles spot prices so the graph will look familiar. The focus here is on the forward curves that are also plotted from 2008 onward. The forward curves represent monthly futures-contract values at which hedges could have been placed as of each of the dates shown in the legend. Inspection of this graph makes it obvious that any hedges placed following the emergence of the 2008 price peak would have yielded losses when compared to the contract expiry price, approximated by the prompt month price in black. That was true through the end of 2011, so four of the five years from 2008 to 2012 would have been costly for targeted-volume hedge plans. I did not illustrate the 2005 price period, but I suspect the same would have been true for the 2005 Katrina-related price peak. Since calendar-based hedges do not utilize risk metrics, companies running targeted-volume programs would have hedged throughout this timeframe and suffered the associated hedge losses. While the spot price graph might have been misinterpreted to indicate each price peak passed in little more than 12 months, the legacy of high cost calendar-based hedges actually went on for years.

Table 8: NYMEX Prompt Month Prices and Selected Forward Curves



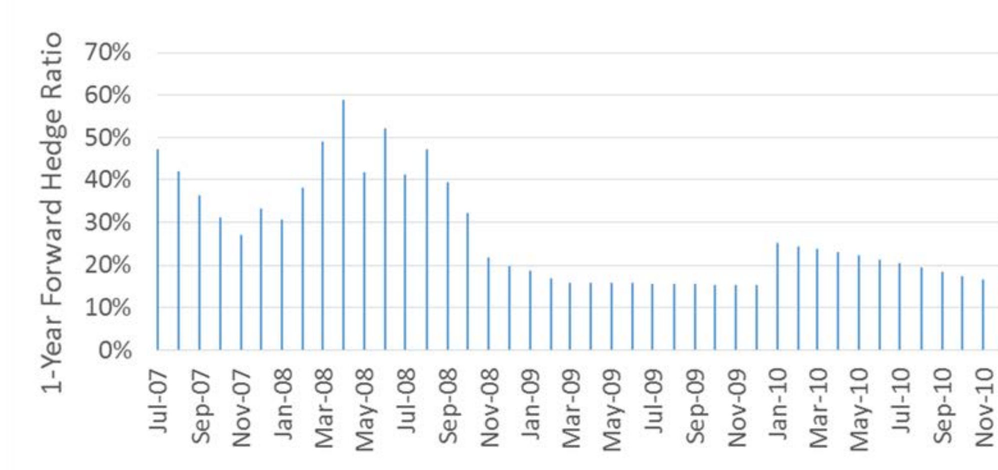
Tables 8 and 9 confirm why risk-responsive programs would have performed better. Table 9 plots the average volatility (red) for the 12 nearest NYMEX contract months at any point in time from 2007 through 2011 along with the prompt-month prices (black). Consider that from 2009 onward, prices were falling but volatility did not fall precipitously until early 2010.

Table 9: Measured Volatility, Average 12 Forward Months, from mid-2007 through 2010



As prices fell and volatility remained high the risk-responsive decision rules shifted from cost concerns to hedge-loss warnings. The strategy's response to that transition is reflected in the simulated hedge ratio which is shown in Table 10. Any risk-responsive program that was averse to hedge-loss tolerances would have substantially reduced or eliminated new hedges shortly after the price peak. In the case of the simulated strategy, hedges were suspended and then shortly later unwound as the price collapse continued. More sophisticated strategies could have used options to navigate these conditions, but computational complexity did not permit this in the Excel simulations.

Table 10: Quantitative-Finance Hedge Ratio, from mid-2007 through 2010



Q. You haven't yet spoken about the hedge window; do the hedge-loss results for programmatic hedges vary much with different hedge windows?

A. Simulated hedge losses do not seem to change much with different hedge windows. Table 11 shows the comparison of worst-year hedge losses for targeted-volume hedging using various hedge windows for the period from 2002 to 2011. The chart indicates that the loss potential was about the same for any reasonable hedge accumulation timeframe.

Table 11: Maximum Losses for Numerous Targeted-Volume Hedge Windows, 2002 - 2011

Programmatic Worst Loss for Various Hedge Accumulation Windows		
Through	Starting	
Mo.# 6	Mo.# 12	-38%
Mo.# 6	Mo.# 18	-41%
Mo.# 12	Mo.# 24	-43%
Mo.# 12	Mo.# 30	-41%
Mo.# 24	Mo.# 36	-40%
Mo.# 24	Mo.# 42	-38%
Mo.# 24	Mo.# 48	-36%

Expressed as % of Average Annual Costs

The reason seems to be related to the recent cycle times from price peaks to price troughs. A careful look at Table 1 reveals that the time from peak to trough for the 2005 and 2008 settlements was about one year. Instinct often leads hedge managers to choose a short hedge window like one year on the theory that a short propagation time should moderate potential losses, but that can result in a lack of smoothing and fairly radical price changes when hedge-to-settlement periods align with market cycle times. Yet longer timeframes allow price migration to propagate longer; the two effects seem to balance, so calendar-based hedging offers little flexibility in addressing loss potential.

Part III – Regulation

Q. Would you describe why you think investor-owned utilities run targeted-volume programs when more sophisticated methods have been available for some time?

A. Customers are a core constituent for utilities but so are shareholders. A regulated utility assumes some shareholder risk whenever it hedges, and that risk is also asymmetrical. In the absence of a more definitive regulatory compact, a utility with a large hedge position has the following two-sided risk exposures: If costs rise, they save customers money and potentially gain modest goodwill for doing what was expected of them; but if costs fall customers' bills will still fall but by less, yet the utility carries hedge losses which may be subject to prudence issues. Even if no prudence finding has ever been levied, the possibility will influence program design.

The utility's asymmetry is exactly opposite that of its customers' described earlier. Customers' risk profiles are improved by rational hedging, but the utility shareholders' risk profile is exacerbated. Formulation of a new regulatory approach might attempt to reconcile the conflict in order to extract more value for ratepayers by reducing prudence risk for utilities who design and execute more robust programs. I will address this later.

It is worth making another observation regarding the typical utility's risk profile and its implications. Once the utility chooses to run a hedging program, it must design it to meet explicit and implicit objectives. Typically those objectives are stated in simple terms such as "reduce volatility", but the underlying nuance is usually at least two-fold: (1) reduce the customers' exposure to cost-related pain and (2) constrain the utility's exposure to prudence risk. That second objective carries a corollary which might be stated this way: any market-oriented decisions could be criticized, so minimize market-responsive decisions to minimize prudence risk. Hence the prevalence of calendar-based hedge programs, where hedge accumulation decisions are made at a policy level at a single point in time for a pre-determined target volume; that policy is then executed as specified, and left in place for the full term with no risk-responsive protocols. If the plan is approved and then executed as crafted, prudence risk is virtually non-existent.

Q. Have you considered how a new regulatory approach might be formulated?

A. I have. The goal would be to promote a more robust structure for hedging strategies while not being overly prescriptive. The first step would be to require contemporaneous weekly risk measurement and monitoring from the customers' perspective, to be reported to the Commission quarterly. These metrics would cover the current fuel adjustment year plus two more, no fewer than twenty-five forward months segmented by fuel adjustment years. Those weekly metrics would include the transient value of the forward gas portfolio for each fuel adjustment year, reflecting hedged volumes at their hedged values and unhedged volumes at market prices. Recorded metrics would also include the transient mark to market, Cost VaR and MtM VaR, as well as the related outliers, Cost Outlier and MtM Outlier. These were all described earlier. The very existence of contemporaneous weekly risk metrics will change behavior and eventually inform prudence determinations. Exhibit ____ (MAG-2), at the end of my testimony, shows a sample three-page format for such a report.

Strategy formulation would be left to utility management, but after one year of reporting risk metrics, I would expect strategies to reflect lower programmatic hedge targets, relying more heavily on defensive hedging protocols and contingent response plans to constrain hedge loss potential. The simple act of requiring such measurement and reporting will change the utilities' perspective on prudence risk. I cannot imagine a scenario where any utility identifies unusually high risk of upside cost exposures or potential high-magnitude hedge losses, and then chooses to ignore those metrics without prudence concerns.

I would recommend that the commission specify common parameters for these reports. For example, cost-oriented risk metrics, could use a 20-workday holding period at 2 standard deviations. If the sentiment is more risk-averse with respect to losses, a holding period of 90 workdays would ensure earlier warnings and a longer response time. These were the holding periods used in the simulations described earlier.

After the first year of risk reporting, I would require that each annual filing of risk management strategies relate the strategy to the risk metrics. This would further promote an improved blend of programmatic, defensive, and contingent protocols. Once again, the prudence risk profile would be better articulated. Companies filing a programmatic-dominant plan will face greater prudence exposures than those with more robust strategies.

Later as experience is gained, the Commission might consider making a policy statement indicating a rebuttable presumption of prudence if key strategy elements are incorporated in the risk management plans and then executed per plan.

Q. You have used various terms in your testimony that might be new to some; could you provide a glossary of terms used in your testimony?

A. Yes. Exhibit **____** (MAG-3) lists the terms as I have defined them throughout the testimony.

Q. Does this conclude your testimony?

A. Yes it does.

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

I, LINDA BOLES, CRR, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney, or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 4th day of November, 2016.

Linda Boles

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