BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

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In the Matter of:

DOCKET NO. 20180001-EI

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

VOLUME 2
PAGES 212 through 389

PROCEEDINGS: HEARING

COMMISSIONERS
PARTICIPATING: CHAIRMAN ART GRAHAM
COMMISSIONER JULIE I. BROWN
COMMISSIONER DONALD J. POLMANN
COMMISSIONER GARY F. CLARK
COMMISSIONER ANDREW G. FAY

DATE: Monday, November 5, 2018

TIME: Commenced: 5:45 P.M.
Concluded: 5:58 P.M.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

APPEARANCES: (As heretofore noted.)

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I N D E X

WITNESSES

NAME:	PAGE NO.
SHANE BOYETT prefiled testimony	215
CODY NICHOLSON prefiled testimony	260
PENELOPE A. RUSK prefiled testimony	269
BRIAN S. BUCKLEY prefiled testimony	306
BENJAMIN F. SMITH prefiled testimony	336
BRENT C. CALDWELL prefiled testimony	345
SIMON O. OJADA prefiled testimony	376
DEBRA N. DOBIAC prefiled testimony	379
DONNA D. BROWN prefiled testimony	382
INTESAR TERKAWI prefiled testimony	385

P R O C E E D I N G S

(Transcript follows in sequence from Volume 2.)

(Prefiled testimony inserted.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony
C. Shane Boyett
Docket No. 20180001-EI
Date of Filing: March 2, 2018

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 Regulatory and Cost Recovery Manager for Gulf Power Company (Gulf or the Company).

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

A. I graduated from the University of Florida in 2001 with a Bachelor of Science degree in Business Administration and earned a Master of Business Administration degree from the University of West Florida in 2005. I joined Gulf Power in 2002 and worked five years as a Forecasting Specialist until I took a position in the Regulatory and Cost Recovery area in 2007 as a Regulatory Analyst. I transferred to Gulf Power's Financial Planning department in 2014 as a Financial Analyst until being promoted to lead the Regulatory and Cost Recovery department later that year. My current responsibilities include oversight of the Company's fuel cost recovery clause, tariff administration, calculation of cost recovery factors and the regulatory filing function of Gulf Power Company.

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

A. The purpose of my testimony is to present the final true-up amounts for the period January 2017 through December 2017 for both the Fuel and Purchased Power Cost Recovery Clause and the Capacity Cost Recovery Clause. I will summarize Gulf Power Company's fuel expenses, net power transaction expense, and purchased power capacity costs, and certify that these expenses were properly incurred during the period January 2017 through December 2017. Lastly, I will present the actual benchmark level for the calendar year 2018 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 2017 through December 2017.

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

A. Yes, I am sponsoring 2 exhibits. Exhibit 1 consists of 7 schedules and includes 2 schedules which relate to the fuel and purchased power cost recovery final true-up, 4 schedules that relate to the capacity cost recovery final true-up and 1 schedule that relates to Gulf's natural gas fuel hedging activities for 2017. Exhibit 2 contains Schedules A-1 through A-9 and A-12 for the period December 2017, previously filed with the Florida Public Service Commission (FPSC or Commission).

Counsel: We ask that Mr. Boyett's exhibits be marked as Exhibit No. _____(CSB-1) and ______(CSB-2).

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. Unless otherwise indicated, the actual data in these documents is taken from the books and records of Gulf Power Company. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by the Commission. Based on the information in these documents and the foregoing testimony, the recoverable fuel and purchased power costs, and hedging activities are reasonable and prudent.

I. FUEL

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

A. Schedules 1 and 2 of my Exhibit CSB-1 relate to the fuel and purchased power cost recovery true-up calculation for the period January 2017 through December 2017 and compare twelve months of actual data to the estimated true-up projections filed in last year's fuel docket which included six months of actual and six months of projected data. In addition, Fuel Cost Recovery Schedules A-1 through A-9 for December 2017 are incorporated herein as Exhibit CSB-2. The A-schedules compare twelve months of actual data to twelve months of projected data from a combination of the original 2017 fuel projection for the months January through June, and the 2017 estimated true-up projections for the months July through December.

Q. What is the final fuel and purchased power cost true-up amount related to the period January 2017 through December 2017 to be addressed through the fuel cost recovery factors in the period January 2019 through December 2019?

A. A net over-recovery amount of $10,213,781, to be returned to customers, was calculated as shown on Schedule 1 of my Exhibit CSB-1.

Q. How was this amount calculated?

A. The $10,213,781 is calculated on Schedule 1 of my Exhibit CSB-1 by taking the difference between the estimated and actual over/under-recovery amounts for the period January 2017 through December 2017. The estimated under-recovery amount was $21,853,354 as compared to the actual under-recovery amount of $11,639,573, resulting in an over-recovery of $10,213,781. The estimated true-up amount for this period was approved in FPSC Order No. PSC-2018-0028-FOF-EI, dated January 8, 2018. Additional details supporting the approved estimated true-up amount are included on Schedules E1-A and E1-B filed August 24, 2017 in Docket No. 20170001-EI.

Q. What are the primary factors which contributed to the final fuel and purchased power cost true-up amount?

A. Gulf Power experienced lower than projected jurisdictional fuel costs of

$4,273,077 together with higher than projected jurisdictional fuel clause revenue of $5,930,236 which combine for an over-recovery, before interest, of $10,203,313 for the period. The resulting difference and the interest provision of $10,467 makes up the remaining variance to reach the total amount of $10,213,781 as calculated on Schedule 2 of my Exhibit CSB-1.

<u>Total Fuel and Net Power Transactions</u>

Q. During the period January 2017 through December 2017, 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 $390,031,885 which is $3,371,486 or 0.86% below the projected amount of $393,403,370. Actual fuel and net power transaction energy was 11,702,772 MWh compared to the projected net energy of 11,878,722 MWh or 1.48% below projections. The resulting actual average cost of 3.3328 cents per kWh was 0.63% above the projected cost of 3.3118 cents per kWh. This information is from Schedule A-1, period-to-date, for the month of December 2017 included in my Exhibit CSB-2. The lower total fuel and net power transaction expense is attributed to a slightly lower quantity of fuel and net power transaction energy than projected for the period as presented above.

Total Fuel Cost of Generated Power

Q. During the period January 2017 through December 2017, 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 $277,982,315 or 7.06% below the projected amount of $299,112,408. Actual generation was 9,247,072 MWh compared to the projected generation of 10,041,442 MWh, or 7.91% below projections. The resulting actual average fuel cost of 3.0062 cents per kWh was 0.92% above the projected fuel cost of 2.9788 cents per kWh. The lower total fuel expense is attributed to the quantity of kWh generated being lower than projected for the period. The actual quantity of fuel consumed was 74,717,455 MMBtu which is 7.53% below the projected quantity of 80,799,509 MMBtu. The weighted average fuel cost for natural gas was 2.78 cents per kWh, which is 4.47% below the projected cost of 2.91 cents per kWh. The weighted average fuel cost for coal, plus lighter fuel, was 3.21 cents per kWh, which is 5.94% higher than the projected cost of 3.03 cents per kWh. This information is found on Schedules A-1 and A-3, period-to-date, for the month of December 2017 included in my Exhibit CSB-2.

Total Cost of Purchased Power

Q. During the period January 2017 through December 2017, 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 $194,889,953 or 8.59% below the estimated amount of $213,201,100. Total megawatt hours of purchased power were 8,242,328 MWh compared to the estimate of 6,616,047 MWh or 24.58% above projections. The resulting average fuel cost of purchased power was 2.3645 cents per kWh or 26.63% below the estimated amount of 3.2225 cents per kWh. This information is from Schedule A-1, period-to-date, for the month of December 2017 included in my Exhibit CSB-2.

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 primarily natural gas-fired energy supplied to Gulf through purchase power agreements. The average fuel cost of energy purchases per kWh was lower than projected for the period due to the availability of lower-cost energy for purchase during the period.

<u>Power Sales</u>

Q. During the period January 2017 through December 2017 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 $103,530,544 or 17.29% below the projected amount of $125,177,500. The total quantity of power sales was 5,659,491 MWh compared to Gulf's projected sales of 4,609,399 MWh, or 22.78% above projections. The resulting average fuel cost of power sold was 1.8293 cents per kWh or 32.64% below the projected amount of 2.7157 cents per kWh. This information is from the December 2017 Schedule A-1, period-to-date, which is included in my Exhibit CSB-2.

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 more favorable position of Gulf's generating assets in system economic dispatch to serve load. This resulted in a greater quantity of lower cost energy sales which has the effect of lowering the average fuel reimbursement rate (cents per kWh) paid to Gulf for typical power sales.

Q. Has the benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for actual 2017 gains?

A. Yes, the three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2015 through 2017 is calculated as follows:

Year	Actual Gain
2015	596,791
2016	700,065
2017	1,988,936
Three-Year Average	$ 1,095,264

Q. What is the actual threshold for 2018?
A. The actual threshold for 2018 is $1,095,264.

II. HEDGING

Q. Did Gulf's fuel hedging activity during 2017 follow Gulf Power's Risk Management Plan for Fuel Procurement?
A. Yes. Gulf Power's fuel hedging strategy in 2017 complied with previously approved Risk Management Plans. Although Gulf did not enter into any new financial hedge contracts in 2017, hedges that settled in 2017 were entered into prior to the current moratorium on natural gas financial hedges and in compliance with previously approved Risk Management Plans.

Q. For the period in question, what volume of natural gas was hedged using a fixed price contract or financial instrument?
A. Gulf Power hedged 28,200,000 MMBtu of natural gas in 2017 using financial instruments. This represents 44% of Gulf's 63,657,955 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 3 of Exhibit CSB-1.

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 were entered into prior to the current moratorium to fix the price of natural 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 2017 through December 2017?

A. No fees, commissions, or premiums were paid by Gulf on the financial hedge transactions during this period. Gulf's 2017 hedging program activities for the period January through December 2017 resulted in a net hedge settlement cost of $24,270,662, as shown on line 2 of the December 2017 Schedule A-1, period-to-date of my Exhibit CSB-2.

III. PURCHASED POWER CAPACITY

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 Exhibit CSB-1 relate to the purchased power capacity cost recovery true-up calculation for the period January 2017 through December 2017. In addition, Schedule A-12 of my Exhibit CSB-2 contains purchased power capacity cost information for the period January 2017 through December 2017.

Q. What is the final purchased power capacity cost true-up amount related to the period of January 2017 through December 2017 to be addressed in the period January 2019 through December 2019?

A. An over-recovery amount of $846,417 should be returned to customers through 2019 purchased power capacity clause rates as shown on Schedule CCA-1 of Exhibit CSB-1.

Q. How was this amount calculated?

A. The $846,417 was calculated by taking the difference between the estimated January 2017 through December 2017 under-recovery of $3,698,545 and the actual under-recovery of $2,852,128, which is the sum of lines 11, 12, and 15 under the total column of Schedule CCA-2 of Exhibit CSB-1. The estimated true-up amount for this period was approved in FPSC Order No. PSC-2018-0028-FOF-EI dated January 8, 2018. Additional details supporting the approved estimated true-up amount are included on Schedules CCE-1A and CCE-1B filed July 27, 2017.

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

A. Schedule CCA-2 shows the monthly calculation of the actual over/under-recovery of purchased power capacity costs for the period January 2017 through December 2017. Schedule CCA-3 of my Exhibit CSB-1 is the monthly calculation of the interest provision on the average recovery balance for the period January 2017 through December 2017.

Q. Please describe Schedule CCA-4 of Exhibit CSB-1.

A. Schedule CCA-4 provides additional details related to purchased power capacity costs which also appear on Lines 1 and 2 of Schedule CCA-2.

Q. During the period January 2017 through December 2017, how did Gulf's actual net purchased power capacity cost compare with the net projected cost?

A. The actual total capacity payments for the period January 2017 through December 2017, as shown on line 5 of Schedule CCA-2 contained in my Exhibit CSB-1, was $82,010,434. Gulf’s total re-projected net purchased power capacity cost for the same period was $82,457,282, as indicated on line 5 of Schedule CCE-1B of my Exhibit CSB-2 filed July 27, 2017 in Docket No. 20170001-EI. The difference between the actual net capacity cost and the projected net capacity cost for the recovery period is $446,848 or 0.5% less than the re-projected amount. The lower actual net cost to customers is due to Gulf having a higher than expected retail credit relating to the Scherer/Flint credit that resulted from the approved 2017 Stipulation and Settlement Agreement in Docket No. 20160186-EI. Excluding the higher than expected Scherer/Flint credit, the net purchased power capacity cost of $86,262,410 was $71,646 or 0.1% less than the re-projected amount of $86,334,056.

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

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
C. Shane Boyett
Docket No. 20180001-EI
July 27, 2018

Q. Please state your name and business address.

A. My name is Shane Boyett. My business address is One Energy Place, Pensacola, Florida 32520. I am the Regulatory and Cost Recovery Manager for Gulf Power Company (Gulf or the Company).

Q. Have you previously filed testimony before this Commission in Docket 20180001-EI?

A. Yes, I provided direct testimony on March 2, 2018.

Q. Has your job description, education, background or professional experience changed since that time?

A. No.

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

A. The purpose of my testimony is to present the estimated true-up amounts for the period January 2018 through December 2018 for both the Fuel and Purchased Power Cost Recovery Clause and the Capacity Cost Recovery Clause. I will also 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 2018 through

December 2018 and summarize any variances in these areas. The current estimated/actual costs consist of actual expenses for the period January 2018 through June 2018 and projected costs for July 2018 through December 2018.

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

A. Yes, I am sponsoring two exhibits. My first exhibit consists of 16 schedules that relate to the fuel and purchased power capacity estimated true-up schedules. My second exhibit contains the calculation of the purchased power capacity credit provision related to Scherer wholesale revenue (Scherer/Flint Credit) contained in the Stipulation and Settlement Agreement that resolved consolidated Docket Nos. 20160186-EI and 20160170-EI.

Counsel: We ask that Mr. Boyett's exhibits be marked as Exhibit Nos. ____ (CSB-3) and ____ (CSB-4).

Q. Are you familiar with the Fuel and Purchased Power (Energy) estimated true-up calculations for the period January 2018 through December 2018, the Purchased Power Capacity Cost estimated true-up calculations for the period January 2018 through December 2018 and the Scherer/Flint Credit calculations as set forth in your exhibits?

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. Unless otherwise indicated, the actual data in these documents is taken from the books and records of Gulf Power Company. The books and records are kept in the regular course of business in accordance with generally accepted accounting principles and practices, and provisions of the Uniform System of Accounts as prescribed by the Commission.

I. FUEL COST RECOVERY CLAUSE

Q. Mr. Boyett, what has Gulf calculated as the fuel cost recovery true-up factor to be applied in the period January 2019 through December 2019?

A. The fuel cost recovery true-up factor for this period is a decrease of 0.1963 cents per kWh. As shown on Schedule E-1A, this calculation includes an estimated over-recovery for the January through December 2018 period of $10,927,716. It also includes a final over-recovery for the January through December 2017 period of $10,213,781 (see Schedule 1 of Exhibit CSB-1 filed in this docket on March 2, 2018). The resulting total over-recovery of $21,141,497 will be incorporated into Gulf's proposed 2019 fuel cost recovery factors.

Q. Does the estimated true-up amount discussed above reflect the provisions of the 2018 Tax Stipulation and Settlement Agreement (2018 Tax Settlement Agreement)?

A. Yes. The applicable schedules contained in my exhibit reflect the fuel-related provisions of the 2018 Tax Settlement Agreement. These provisions include lower fuel cost recovery rates effective April 2018 that implemented a $73.2 million rate reduction during the period April 2018 through December 2018. The 2018 Tax Settlement Agreement was approved by Florida Public Service Commission (FPSC or Commission) Order No. PSC-2018-0180-FOF-EI in Docket 20180039-EI dated April 12, 2018.

Q. Please explain the variances on Schedule E-1B-1.

A. Below is an explanation of key areas of Schedule E-1B-1 of my Exhibit CSB-3.

<u>Total Fuel and Net Power Transactions (Schedule E-1B-1, line 14)</u>

Gulf's currently projected recoverable total fuel and net power transactions cost for the period is $381,141,686, which is $12,308,432, or 3.13% lower than the original projected amount of $393,450,117. The lower total fuel and net power transactions cost for the period is attributed to higher than expected revenue from power sales and lower purchased power expense, partially offset by higher fuel cost of generated power. The resulting average per unit fuel and net power transactions cost is estimated to be 3.2142 cents per kWh, or 3.30% lower than the original projection of 3.3240 cents per kWh.

<u>Total Cost of Generated Power (Schedule E-1B-1, line 4)</u>

Gulf's currently projected recoverable total fuel cost of generated power for the twelve months ending December 2018 is $282,785,430, which is $7,184,133, or 2.61% above the original projected amount of $275,601,297. Total generation is expected to be 9,169,152 MWh compared to the original projected generation of 8,752,133 MWh, or 4.76% above original projections. The resulting average fuel cost is expected to be 3.0841 cents per kWh, or 2.06% below the original projected amount of 3.1490 cents per kWh.

The total fuel cost of system net generation for the first six months of 2018 was $113,971,631, which is $3,809,143, or 3.23% lower than the projected cost of $117,780,774. On a fuel cost per kWh basis, the actual cost was 2.93 cents per kWh, which is 3.62% lower than the projected cost of 3.04 cents per kWh. This lower than projected cost of system generation on a cents per kWh basis was due to lower than projected natural gas prices and a higher mix of natural gas-fired generation for the period. This information is found on Schedule A-3, Period to Date, of the June 2018 Monthly Fuel Filing.

The total cost of coal burned (including boiler lighter) for the first six months of 2018 was $57,484,892, which is $2,059,023, or 3.46% lower than the projection of $59,543,915. Total coal-fired generation was 1,786,387 MWh, which is 5.00% lower than the projection of 1,880,334 MWh for the period. On a fuel cost per kWh basis, the actual cost was 3.22 cents per kWh, which is 1.58% higher than the projected cost of 3.17 cents per kWh. The slightly higher per kWh cost of coal-fired generation is due to actual coal prices (including boiler lighter) being 2.85% higher than projected on a $/MMBtu basis, partially offset by the weighted average heat rate (Btu/kWh) of the coal-fired generating units that operated performing 1.13% better than projected. This information is found on Schedule A-3, Period to Date, of the June 2018 Monthly Fuel Filing. Gulf has fixed price coal contracts in place for the period to limit price volatility and ensure reliability of supply.

While Gulf burned more natural gas than projected during this period, the total cost and the cost per unit were less than projected. The total cost of natural gas burned for generation for the first six months of 2018 was $55,985,121, which is $1,786,898, or 3.09% lower than Gulf's projection of $57,772,018. The total gas-fired generation was 2,096,979 MWh, which is 5.56% higher than the projection of 1,986,488 MWh for the period. Gulf's gas-fired generating units consumed 14,653,922 MMBtu, or 8.31% more than the projected amount of 13,529,727 MMBtu during the period. On a cost per unit basis, the actual cost of gas-fired generation was 2.67 cents per kWh, which is 8.25% lower than the projected cost of 2.91 cents per kWh. The lower than projected per kWh cost of gas-fired generation is due to actual gas prices being 10.55% lower than projected on a $/MMBtu basis for the six-month period. This information is found on Schedule A-3, Period to Date, of the June 2018 Monthly Fuel Filing.

<u>Total Fuel Cost and Gains on Power Sales (Schedule E-1B-1, line 12)</u>

Gulf's currently projected recoverable fuel cost and gains on power sales for the twelve months ending December 2018 are $106,979,823, or 15.77% above the original projected amount of $92,403,521. Total power sales are expected to be 3,809,951 MWh, in comparison to the original projection of 3,621,814 MWh, or 5.19% above projections. The currently projected price for the fuel cost and gains on power sales is 2.8079 cents per kWh, which is 10.06% higher than the original projection of 2.5513 cents per kWh. The higher projected fuel reimbursement rate for power sales during the period is due to higher fuel costs associated with the units that set system pool interchange rates for power sales during periods of extreme winter weather in the first quarter of 2018.

The total fuel cost of power sold for the first six months of 2018 was $39,183,493, which is $8,580,278, or 28.04% higher than the projection of $30,603,214. The quantity of power sales for the period was 10.43% lower than projected. The actual cost was 3.5461 cents per kWh, which is 42.94% above the projected cost of 2.4808 cents per kWh. This information is found on Schedule A-1, Period to Date, line 12 of the June 2018 Monthly Fuel Filing.

<u>Total Cost of Purchased Power (Schedule E-1B-1, line 7)</u>

Gulf's currently projected recoverable fuel cost of purchased power for the twelve months ending December 2018 is $205,336,079, or 2.34% below the original projected amount of $210,252,341. The total amount of purchased power is expected to be 6,498,769 MWh, in comparison to the original projection of 6,706,285 MWh, or 3.09% below projections. The resulting average fuel cost of purchased power is expected to be 3.1596 cents per kWh, or 0.78% above the original projected amount of 3.1352 cents per kWh. The lower total fuel cost of purchased power is attributed to lower than projected quantities of purchased power for the period.

The total fuel cost of purchased power for the first six months of 2018 was $97,705,135, which is $2,301,454, or 2.41% higher than the original projection of $95,403,681, and the quantity of purchased power was on budget at 0.01% below original projections. The higher than projected purchased power expense is due to higher cost purchases made during the extreme winter weather in the first quarter of 2018. On a fuel cost per kWh basis, the actual cost was 3.3292 cents per kWh, which is 2.42% higher than the projected cost of 3.2505 cents per kWh. This information is found on Schedule A-1, Period to Date, line 7 of the June 2018 Monthly Fuel Filing. A majority of Gulf's purchases are from energy or power purchase agreements (PPAs), which include contracts associated with a gas-fired generating unit and multiple renewable energy purchase agreements.

II. HEDGING

Q. Please briefly discuss the status of Gulf's hedging program.

A. There has been no change in the status of Gulf's hedging program. Gulf's hedging program is currently subject to a moratorium pursuant to the Joint Stipulation and Agreement for Interim Resolution of Hedging Issues filed on October 24, 2016, in Docket No. 20160001-EI and approved by the Commission in Order No. PSC-16-0547-FOF-EI. Subsequently, on March 20, 2017, Gulf filed a Stipulation and Settlement Agreement which resolved all issues in consolidated Docket Nos. 20160186-EI and 20160170-EI. As part of the Stipulation and Settlement Agreement approved by the Commission in Order No. PSC-17-0178-S-FOF-EI, the existing moratorium for new natural gas financial hedges shall continue until January 1, 2021. Accordingly, Gulf has not entered into any new financial natural gas hedges since the effective date of the stipulated moratorium.

Q. For the period January 2018 through June 2018, what volume of natural gas was hedged using a fixed price contract or instrument?

A. Under previously-approved Risk Management Plans, Gulf Power financially hedged 1,420,000 MMBtu of natural gas for the period. This equates to 26% of the actual natural gas burn for Gulf's combined cycle generating units during the period of 5,504,659 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 2018 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 hedging settlement costs of $7,645,700 for the period January through June 2018. This information is found on Schedule A-1, Period to Date, line 1a of the June 2018 Monthly Fuel Filing.

III. FUEL PROCUREMENT

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

A. No.

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 receives reimbursement 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.

IV. PURCHASED POWER CAPACITY

Q. Mr. Boyett, you stated earlier that you are responsible for the Purchased Power Capacity Cost (PPCC) true-up calculation. Which schedules of your Exhibit CSB-3 relate to the calculation of these factors?

A. Schedules CCE-1A, CCE-1B, CCE-2, CCE-3 and CCE-4 of my exhibit relate to the Purchased Power Capacity Cost true-up calculation.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2019 through December 2019?

A. The true-up for this period is a decrease of 0.0189 cents per kWh, as shown on Schedule CCE-1A. This calculation includes an estimated over-recovery of $1,187,593 for January 2018 through December 2018. It also includes a final over-recovery of $846,417 for the period January 2017 through December 2017 (see Schedule CCA-1 of Exhibit CSB-1 filed in this docket on March 2, 2018). The resulting total over-recovery of $2,034,010 will be incorporated into Gulf's proposed 2019 purchased power capacity cost recovery factors.

Q. During the period January 2018 through December 2018, what is Gulf's projection of purchased power capacity costs and how does it compare with the original projection of capacity costs?

A. As shown on Schedule CCE-1B, lines 1 and 2, of Exhibit CSB-3, Gulf's total capacity payments projection for the January 2018 through December 2018 recovery period is $85,412,496. Gulf's original projection for the period was

$86,277,012 and is shown on lines 1 and 2 of Schedule CCE-1 filed August 24, 2017. The difference between these projections is $864,516, or 1.00% lower than the original projection of capacity payments.

Q. How did the total projected capacity costs compare to the actual cost for the first six months of 2018?

A. Actual capacity costs during the first six months of 2018 were $42,341,956 (Lines 1 & 2 of Schedule CCE-1B), which is $844,202 lower than projected amount of $43,186,158 for the period (from Lines 1 & 2 of Schedule CCE-1 filed August 24, 2017).

Q. Please describe how the Stipulation and Settlement Agreement in consolidated Docket Nos. 20160186-EI and 20160170-EI is applied to the Capacity Clause as it relates to the portion of Gulf's ownership of Scherer Unit 3 that is still committed to a wholesale customer.

A. I have prepared Exhibit CSB-4 to present the calculation of Flint Electric Membership Corporation (Flint) wholesale contract revenue that was committed to retail customers pursuant to the relevant provisions of the approved Stipulation and Settlement agreement. The credit that is included in the PPCC is equal to total Flint revenue less the environmental cost recovery revenue requirements and fuel costs attributable to the portion of Scherer Unit 3 that is currently contracted to Flint through December 2019. The total estimated Scherer/Flint credit for 2018 is $8,955,368. The estimated Scherer/Flint Credit for the period January through December 2018, as shown on line 4 of Schedule CCE-1B of

Exhibit CSB-3, has the effect of lowering retail capacity payments (line 5). The calculation of the credit, as presented in Exhibit CSB-4, is performed in accordance with the Stipulation and Settlement Agreement approved by Order No. PSC-17-0178-S-EI in the consolidated Docket Nos. 20160186-EI and 20160170-EI.

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

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
C. Shane Boyett
Docket No. 20180001-EI
Date of Filing: August 24, 2018

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 Regulatory and Cost Recovery Manager for Gulf Power Company.

Q. Have you previously filed testimony before the Florida Public Service Commission (FPSC or Commission) in Docket No. 20180001-EI?

A. Yes, I provided direct testimony on March 2, 2018, and on July 27, 2018.

Q. Has your education, background or professional experience changed since that time?

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the projection of fuel expenses, net power transaction expense, and purchased power capacity costs for the period January 1, 2019, through December 31, 2019, along with the resulting calculation of Gulf Power's fuel cost recovery and purchased power capacity factors for the period January 2019 through December 2019.

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 as shown below.

<u>Exhibit Number</u>	<u>Summary</u>
CSB-5	23 schedules related to Fuel and Purchased Power Capacity Calculations
CSB-6	2019 Scherer/Flint Credit Calculation
CSB-7	Gulf Power Company's Hedging Information Report filed with the Commission Clerk on April 3, 2018, and assigned Document Number DN 02704-2018 (redacted) and 02700-2018 (confidential information). This exhibit details Gulf Power's natural gas hedging transactions for August 2017 through December 2017 in compliance with Order No. PSC-08-0316-PAA-EI.
CSB-8	Gulf Power Company's Hedging Information Report filed with the Commission Clerk on August 10, 2018, and assigned Document Number DN 05228-2018 (redacted) and DN 05241-2018 (confidential information). This exhibit details Gulf Power's natural gas hedging

transactions for January 2018 through July 2018 in compliance with Order No. PSC-08-0316-PAA-EI.

Counsel: We ask that Mr. Boyett's exhibits as described be marked for identification as Exhibit Nos. _____(CSB-5), _____(CSB-6), _____(CSB-7), and _____(CSB-8).

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.

I. FUEL

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 2019 through December 2019.

A. As shown on Revised Schedule E-1A of Exhibit CSB-5, the total true-up amount of $23,409,339 includes an estimated over-recovery for the January 2018 through December 2018 period of $13,195,558, in addition to a final over-recovery for the period January through December 2017 of $10,213,781. The estimated over-recovery for the January 2018 through December 2018 period has been revised since the filing of my estimated true-up testimony on

July 27, 2018, to include one additional month of actual data. The true-up amount now includes seven months of actual data and five months of estimated data, as reflected on Revised Schedule E-1B of Exhibit CSB-5.

Q. Does the estimated true-up amount discussed above reflect the provisions of the 2018 Tax Stipulation and Settlement Agreement (2018 Tax Settlement Agreement)?

A. Yes. The applicable schedules contained in my Exhibit CSB-5 reflect the fuel clause related provisions of the 2018 Tax Settlement Agreement. These provisions include lower fuel cost recovery rates effective April 2018 that implemented a $73.2 million rate reduction during the period April 2018 through December 2018. They also include an additional ratemaking adjustment for the 2019 period representing an estimate of the 2018 tax savings amount reserved on Gulf's balance sheet relating to protected excess deferred taxes that are being returned to customers consistent with the 2018 Tax Settlement Agreement and IRS normalization rules. The 2018 Tax Settlement Agreement was approved by Commission Order No. PSC-2018-0180-FOF-EI in Docket No. 20180039-EI dated April 12, 2018.

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of January 2017 through December 2017?

A. The GPIF result shown on Line 27 of Schedule E-1 is a decrease of 0.0024 cents per kWh to the levelized fuel factor, thereby penalizing Gulf $256,872.

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 25 of Schedule E-1.

Q. What is the levelized projected fuel factor for the period January 2019 through December 2019?
A. Gulf has proposed a levelized fuel factor of 3.030 cents per kWh. This factor is based on projected fuel and purchased power energy expenses and projected kWh sales for January 2019 through December 2019 and includes the true-up and GPIF amounts identified above. The projected levelized fuel factor for 2019 also includes a $9,946,000 credit relating to the estimated tax savings adjustment discussed above, as contemplated in the 2018 Tax Settlement Agreement.

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 3.047 cents per 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 2019 through December 2019 and include the GPIF, true-up amount and estimated tax savings credit. These time-of-use fuel factors as shown on Schedule E-1E have all been adjusted for line losses.

Q. How does the proposed fuel factor for Rate Schedule RS compare with the factor applicable to December 2018, 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 2018 is 2.949 cents per kWh compared with the proposed factor of 3.047 cents per kWh. For a residential customer who is billed for 1,000 kWh in January 2019, the fuel portion of the bill, including tax savings adjustments, would increase from $29.49 to $30.47.

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 2019 through December 2020. In addition, pursuant to Commission Order

No. PSC-16-0119-TRF-EG in Docket No. 150248-EG, Gulf has calculated the bill credit for participants of the Community Solar Pilot Program to be $1.74 per month based on the 2019 projected solar-weighted average annual avoided energy cost of 2.8 cents per kWh.

Q. What amount have you calculated to be the appropriate benchmark level for calendar year 2019 gains on non-separated wholesale energy sales eligible for a shareholder incentive?

A. In accordance with Order No. PSC-00-1744-PAA-EI, an estimated three-year average benchmark level has been calculated as follows:

2016 actual gains	700,065
2017 actual gains	1,988,936
2018 estimated gains	240,157
Three-Year Average	$ 976,386

This amount represents the minimum projected threshold for 2019 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% of the gains on non-separated sales for 2019.

Total Fuel and Net Power Transactions

Q. What is Gulf's projected recoverable total fuel and net power transactions cost for the January 2019 through December 2019 recovery period?

A. Gulf's projected total fuel and net power transactions cost for the period is $369,299,689 as shown on Schedule E-1 line 16 of Exhibit CSB-5.

Q. How does the total projected fuel and net power transactions cost for the 2019 period compare to the updated projection of fuel cost for the same period in 2018?

A. The total updated cost of fuel and net power transactions for 2018, reflected on Schedule E-1B-1 line 14 of Exhibit CSB-3 filed in this docket on July 27, 2018, is projected to be $381,141,686. The projected total cost of fuel and net power transactions for the 2019 period reflects a decrease of $11,841,997 or 3.11% lower than the same period in 2018. On a fuel cost per kWh basis, the 2018 projected cost is 3.2142 cents per kWh, and the 2019 projected fuel cost is 3.1670 cents per kWh, a decrease of 0.0472 cents per kWh or 1.47%.

<u>Total Cost of Generated Power</u>

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 2019 as shown in Exhibit CSB-5, Schedule E-1, line 5 is $260,352,584.

Q. How does the projected total fuel cost of generated power for the 2019 period compare to the updated projection of fuel cost for the same period in 2018?

A. The total updated cost of fuel to meet 2018 system generated power needs, reflected on Schedule E-1B-1, line 4 of CSB-3 filed in this docket on July 27, 2018, is projected to be $282,785,430. The projected total cost of fuel to meet system net generation needs for the 2019 period reflects a decrease of $22,432,846 or 7.93% less than the same period in 2018. Total system net generation in 2019 is projected to be 8,760,506 MWh, which is 408,646 MWh or 4.46% less than projected for 2018. The lower projected total fuel expense is the result of a lower projected quantity of total MWh produced combined with lower estimated hedging settlement costs for the period. On a fuel cost per kWh basis, the 2018 projected cost is 3.0841 cents per kWh, and the 2019 projected fuel cost is 2.9719 cents per kWh, a decrease of 0.1122 cents per kWh or 3.64%.

Weighted average coal burned price including boiler lighter fuel for 2018 as reflected on Schedule E-3, line 32 of my testimony filed in this docket on July 27, 2018, is projected to be $2.83 per MMBtu. Weighted average coal burned price including boiler lighter fuel for 2019, as reflected on Schedule E-3, line 32 is projected to be $2.96 per MMBtu. These figures reflect a cost increase of $0.13 per MMBtu or 4.59%. Weighted average natural gas price for 2018, as reflected on Schedule E-3, line 33 of the exhibit to my testimony filed in this docket on July 27, 2018, is projected to be $3.80 per MMBtu. Weighted average natural gas price for 2019, as reflected on Schedule E-3, line 33 is projected to be $3.65 per MMBtu. This is a decrease in price of $0.15 per MMBtu or 3.95%.

As reflected on Schedule E-3, lines 40 and 41, the projected fuel cost of Gulf’s coal-fired generation is 3.25 cents per kWh, and the projected fuel cost of Gulf’s gas-fired generation is 2.52 cents per kWh for the 2019 period.

Fuel Cost and Gains on Power Sales

Q. What are Gulf's projected recoverable fuel cost and gains on power sales for the 2019 period?

A. Gulf's projected recoverable fuel cost and gains on power sales is $105,253,229 as shown on Schedule E-1, line 14.

Q. How does the total projected recoverable fuel cost and gains on power sales for the 2019 period compare to the projected recoverable fuel cost and gains on power sales for the same period in 2018?

A. The total updated recoverable fuel cost and gains on power sales in 2018, reflected on Schedule E-1B-1, line 12 of my exhibit filed in this docket on July 27, 2018, is projected to be $106,979,823. The projected recoverable fuel cost and gains on power sales in 2019 represents a decrease of $1,726,594 or 1.61%. Total quantity of power sales in 2019 is projected to be 4,417,871 MWh, which is 607,919 MWh or 15.96% higher than currently projected for 2018. On a fuel cost per kWh basis, the 2018 projected cost is 2.8079 cents per kWh, and the 2019 projected fuel cost is 2.3824 cents per kWh, which is a decrease of 0.4255 cents per kWh or 15.15%. The higher total credit to fuel expense from power sales is attributed to a higher projected quantity of power sales from units operating to meet incremental system loads offset by lower average unit fuel cost of power sales.

Total Cost of Purchased Power

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

A. Gulf's projected recoverable cost for energy purchases is $214,200,334 as shown on Schedule E-1, line 9.

Q. How does the total projected purchased power cost for the 2019 period compare to the projected purchased power cost for the same period in 2018?

A. The total updated cost of purchased power to meet 2018 system needs, reflected on Schedule E-1B-1, line 7 of my testimony filed in this docket on July 27, 2018, is projected to be $205,336,079. The projected cost of purchased power to meet system needs in 2019 is an increase of $8,864,255 or 4.32% higher than currently projected for 2018. The total quantity of purchased power in 2019 is projected to be 7,318,073 MWh, which is 819,304 MWh or 12.61% higher than is currently projected for 2018. On a fuel cost per kWh basis, the 2018 projected cost is 3.1596 cents per kWh, and the 2019 projected fuel cost is 2.9270 cents per kWh, which represents a decrease of 0.2326 cents per kWh or 7.36%. The higher total cost of purchased power is attributed to a higher projected quantity of purchased power energy offset by lower average unit fuel cost of purchased power.

II. FUEL PROCUREMENT

Q. Does the 2019 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.

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

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

III. HEDGING

Q. Has anything changed with regard to the status of Gulf's hedging program since filing testimony on July 27, 2018, in this docket?

A. There has been no change in the status of Gulf's hedging program. However, actual hedging settlement data has become available for the month of July 2018 and is included in my Exhibit CSB-8 as previously filed with this Commission on August 10, 2018.

Q. What are the results of Gulf's natural gas price hedging program for the period August 2017 through July 2018?

A. Gulf had financial hedges in place during the period to hedge the price of natural gas. These financial hedges have been effective in fixing the price of a percentage of Gulf's gas burn during the period. Between August 2017 and July 2018, Gulf recorded hedging settlement costs of $20,129,290. Pursuant to Order No. PSC-08-0316-PAA-EI, Gulf filed Hedging Information Reports with the Commission on April 3, 2018, and August 10, 2018, detailing its natural gas hedging transactions for August 2017 through July 2018. I am sponsoring these reports as Exhibits CSB-7 and CSB-8 to my testimony in this docket.

IV. PURCHASED POWER CAPACITY

Q. You stated earlier that you are responsible for the calculation of the purchased power capacity cost (PPCC) recovery factors. Which of your exhibits 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-5 and Exhibit CSB-6 relate to the calculation of the PPCC recovery factors for the period January 2019 through December 2019.

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

A. Schedule CCE-1 shows the calculation of jurisdictional capacity costs to be recovered through the PPCC Recovery Clause. Lines 1 through 3 show Gulf's projected net capacity expense, which includes a credit for transmission revenue. Line 4 reflects the inclusion of the Scherer/Flint Credit, which is calculated and presented in my Exhibit CSB-6. The total net projected capacity costs are applied to a jurisdictional factor and added to the total true-up which is then adjusted for revenue taxes to determine the amount to be recovered in the period through PPCC recovery factors.

Q. What is the appropriate revenue tax factor to be applied in calculating the total recoverable capacity payments?

A. A revenue tax factor of 1.00072 has been applied to all jurisdictional purchased power capacity costs, as shown on Line 10 of Schedule CCE-1.

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 17-0178-S-EI in consolidated Docket Nos. 160186-EI and 160170-EI. This allocation is consistent with the treatment accorded to production plant in the cost of service study approved by the Commission in Gulf's most recent base rate proceeding. 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.

Q. How were the rate class allocation factors used in the PPCC Recovery Clause calculated?

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. and adjusted for losses. The energy allocation factors were calculated based on projected kWh sales for the period and 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 PPCC recovery 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 $7.76.

Q. What is Gulf’s projected recoverable capacity payments for the 2019 cost recovery period?

A. The total recoverable capacity payments for the period are $72,412,251. This amount is captured in the Schedule CCE-1, line 11. Schedule CCE-4 shows the projected cost associated with the 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 2019 projection of capacity cost is revenue produced by a market-based agreement between the Southern electric system operating companies and South Carolina PSA (Public Service Authority). The total capacity cost of $86,048,498 is shown on Schedule CCE-4, line 14. 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 other projected revenues or credits has Gulf included in its capacity cost recovery clause for the period?
A. Gulf has included an estimate of transmission revenues in the amount of $110,000 in its capacity cost recovery projection. This amount is captured on Schedule CCE-1, line 3 of my Exhibit CSB-5. Also, pursuant to the Stipulation and Settlement Agreement approved by Order No. PSC 17-0178-S-EI in consolidated Docket Nos. 160186-EI and 160170-EI, Gulf is including an estimated Scherer/Flint Credit in the amount of $9,387,728 for the 2019 period. The Scherer/Flint Credit calculation is presented in my Exhibit CSB-6, and it also appears on Schedule CCE-1, line 4 of my Exhibit CSB-5 as an offset to capacity payments.

Q. How do the total projected net jurisdictional capacity payments for the 2019 period compare to the current estimated net jurisdictional capacity payments for the same period in 2018?
A. Gulf's 2019 Projected Jurisdictional Capacity Payments, found on Schedule CCE-1, line 7, are $74,394,162. This amount is $226,266 or 0.31% less than the current estimate of $74,167,896 (Schedule CCE-1B, line 7) for 2018 that was filed in my actual/estimated true-up testimony in this docket on July 27, 2018. The projected jurisdictional capacity payments for 2019 are essentially flat compared to the updated estimate for the 2018 period.

Q. When does Gulf propose to collect these new fuel charges and purchased power capacity charges?
A. The fuel and capacity recovery factors will be effective beginning with the first billing cycle in January 2019 and continuing through the last billing cycle of December 2019.

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. 20180001-EI
Date of Filing: March 15, 2018

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, 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 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 22 of

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

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

A. Actual equivalent availability and adjusted actual equivalent availability figures for each of the Company's GPIF units are shown on page 12 of Schedule 5. Pages 3 through 7 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-2018-0028-FOF-EI is on page 8 of Schedule 2. The results are: Scherer 3, +10.00 points; Crist 7, -10.00 points; Daniel 1, +10.00 points; Daniel 2, +10.00 points; and Smith 3, +10.00 points.

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

A. The detailed calculations of the actual average net operating heat rates for the Company's GPIF units are on pages 2 through 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 September 2016, 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:

Scherer 3, 0.00 points; Crist 7, 0.00 points; Daniel 1, -10.00 points; Daniel 2, -3.05 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 -0.77 as indicated on page 2 of Schedule 4. This calculated to a penalty in the amount of $256,872.

Q. Please summarize your testimony.

A. In view of the adjusted actual equivalent availabilities, as shown on page 8 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 $256,872 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 and Exhibit of
C. L. Nicholson
Docket No. 20180001-EI
Date of Filing: August 24, 2018

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 the 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, 2019 through December 31, 2019.

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 87% of Gulf's projected net generation for 2019.

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, 2019 through December 31, 2019?

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, 2019 through December 31, 2019.
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 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, and during my tenure there I assumed positions of increasing responsibility. I have over 20 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 position is Manager, Rates, and my responsibilities 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 2017 through December 2017 for the Fuel and Purchased Power Cost Recovery Clause ("Fuel Clause") and the Capacity Cost Recovery Clause ("Capacity Clause"). I also describe the change in the fuel clause incentive mechanism, effective beginning with January 2018, which eliminates the need for the wholesale incentive benchmark.

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 2017 through December 2017?

A. The final true-up amount for the Capacity Clause for the period January 2017 through December 2017 is an under–recovery of $1,952,049.

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 2017 Through December 2017," provides the calculation for the final under–recovery of $1,952,049. The actual capacity cost under-recovery, including interest, was $4,714,987 for the period January 2017 through December 2017 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the $2,762,938 actual/estimated under-recovery approved in Order No. PSC-2018-0028-FOF-EI issued January 8, 2018 in Docket No. 20180001-EI, results in a final under-recovery of $1,952,049 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 2019 through December 2019.

Q. What is the estimated effect of this $1,952,049 under-recovery for the January 2017 through December 2017 period on residential bills during the January 2019 through December 2019 period?

A. The $1,952,049 under-recovery will increase a 1,000 kWh residential bill by approximately $0.12.

Fuel and Purchased Power Cost Recovery Clause

Q. What is the final true-up amount for the Fuel Clause for the period January 2017 through December 2017?

A. The final Fuel Clause true-up for the period January 2017 through December 2017 is an over-recovery of $7,199,907. The actual fuel cost over-recovery, including interest, was $24,281,044 for the period January 2017 through December 2017. This $24,281,044 amount, less the $17,081,137 actual/estimated over-recovery amount approved in Order No. PSC-2018-0028-FOF-EI, issued January 8, 2018 in Docket No. 20180001-EI, results in a net over-recovery amount for the period of $7,199,907.

Q. What is the estimated effect of the $7,199,907 over-recovery for the January 2017 through December 2017 period on residential bills during the January 2019 through December 2019 period?

A. The $7,199,907 over-recovery will decrease a 1,000 kWh residential bill by approximately $0.37.

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 2017 Through December 2017." It shows the calculation of the final fuel over-recovery of $7,199,907.

Line 1 shows the total company fuel costs of $645,103,254 for the period January 2017 through December 2017. The jurisdictional amount of total fuel costs is $645,024,816, 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 $40,822,751 over-recovered fuel costs for the period, adjustments, interest, true-up collected, and the prior period true-up shown on lines 5 through 8 respectively, constitute the actual over-recovery amount of $24,281,044 shown on line 9. The $24,281,044 actual amount less the $17,081,137 actual/estimated over-recovery amount shown on line 10, results in a final over-recovery amount of $7,199,907 for the period January 2017 through December 2017, as shown on line 11.

Q. Please describe the nature of adjustments in the amount of $4,529,041, as shown on line 5.

A. The $4,529,041 includes two adjustments. The first adjustment, in the amount of $4,524,936, relates to a December 2017 adjustment for Big Bend Unit 2 outage replacement power cost. The June 29, 2017 incident that occurred at Big Bend Unit 2 resulted in the unit being taken off-line while an OSHA investigation into the incident was conducted. Big Bend Unit 2 remained off-line during the investigation before eventually returning to service on August 17, 2017. In late December, OSHA issued citations to Tampa Electric related to the incident. While the company has contested the citations, it has elected to absorb these replacement power costs as company costs rather than seeking to recover them from its customers. The second adjustment, in the amount of $4,105, is the March 2017 adjustment to true up 2016 fuel costs associated with the Reedy Creek separated wholesale sale.

Q. Is the December 2017 Big Bend Unit 2 outage adjustment a final amount?

A. No, the adjustment of $4,524,936 was estimated, and the company made the December 2017 adjustment with the intention to complete a detailed hourly analysis and true up the amount in the following month, if necessary. The adjustment was trued up in January 2018.

Q. Please describe the calculation of the estimated and final adjustment amounts.

A. Tampa Electric back-casts as-available energy prices every month using actual fuel prices, customer load, and unit availability, with the hourly production cost simulation software Generation Operations, a software product of ABB. To evaluate the impact of the Big Bend Unit 2 outage on fuel and purchased power costs, Tampa Electric employed the same process and modeled actual system fuel prices, load, and unit availability during the time period of the outage using Generation Operations.

The reference case included the Big Bend Unit 2 outage. The change case was prepared with Big Bend Unit 2 available for economic dispatch during the entire study period. The dispatch of Big Bend Unit 2 in the change case showed that the unit would have been able to replace some, but not all, of the actual purchased power costs that occurred during the time period of the outage. The detailed hourly analysis of replacement power costs was determined by subtracting the change case from the reference case.

Purchased power costs as a result of the outage were compared to what the cost of operating Big Bend Unit 2 would have been, using the actual MWh priced at the average fuel cost and average heat rate of Big Bend Unit 2. The difference between the fuel and purchased power costs of the two cases resulted in the estimated $4,524,936 adjustment in the December filing. Since averages were used for this estimate, a detailed hourly analysis was still needed to true it up.

In January 2018, Tampa Electric completed the hourly analysis, and calculated total actual replacement power costs of $4,334,524. The company booked the resulting true-up adjustment of $190,412, and it was reported on the company’s January 2018 Schedule A1 submitted to the Commission on February 26, 2018.

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 2017 Through December 2017." 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 2017 through December 2017?

A. As shown on line A7 of Document No. 3, the fuel and net power transaction cost is $40,690,560 less than the amount originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2017 through December 2017?

A. As shown on line C3 of Document No. 3, the company collected $1,017,293, or 0.1 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 2017 through December 2017. 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 2017 through December 2017 are less than the project’s fuel savings and provide a net benefit to customers. 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-2012-0498-PAA-EI, issued in Docket No. 20120153-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, and provide a net benefit to customers, 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-2014-0309-PAA-EI, issued in Docket No. 20140032-EI on June 12, 2014.

Wholesale Incentive Benchmark and Optimization Mechanism

Q. Will Tampa Electric set a 2018 wholesale incentive benchmark that is derived in accordance with Order No. PSC-01-2371-FOF-EI issued in Docket No. 010283-EI?

A. No. Effective January 1, 2018, as authorized by FPSC Order No. PSC-2017-0456-S-EI, issued in Docket No. 20160160-EI on November 27, 2017, the company’s Optimization Mechanism replaced the existing short-term wholesale sales incentive mechanism, and as a result no incentive benchmark is required for 2018. Under the new program, for the four-year period from 2018 through 2021, gains on all optimization mechanism activities, including short-term wholesale sales, short-term wholesale purchases, and all forms of asset optimization undertaken each year will be shared between shareholders and customers. The sharing thresholds are (a) for the first $4.5 million per year, 100 percent of gains to customers; (b) for gains greater than $4.5 million per year and less than $8.0 million per year, split 60 percent to shareholders and 40 percent to customers; and (c) for gains greater than $8.0 million per year, 50-50 sharing between shareholders and customers.

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. Have you previously filed testimony in Docket No. 20180007-EI?

A. Yes, I submitted direct testimony on April 2, 2018.

Q. Has your job description, education, or professional experience changed since then?

A. No.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2018 through December 2018 actual/estimated true-up amount to be refunded or recovered through the Environmental Cost Recovery Clause ("ECRC") during the period January 2019 through December 2019. My testimony addresses the recovery of capital and operations and maintenance ("O&M") costs associated with environmental compliance activities for 2018, based on six months of actual data and six months of estimated data. This information will be used in the determination of the environmental cost recovery factors for January 2019 through December 2019.

Q. Have you prepared exhibits that show the recoverable environmental costs for the actual/estimated period of January 2018 through December 2018?

A. Yes, I prepared two exhibits. Exhibit No. PAR-2, containing nine documents, was prepared under my direction and supervision. It includes Forms 42-1E through 42-9E, which show the current period actual/estimated true-up amount to be used in calculating the cost recovery factors for January 2019 through December 2019. Exhibit No. PAR-3, which contains seven documents, includes selected schedules without the costs of Tampa Electric's two new proposed ECRC projects for compliance with the Effluent Limitations Guidelines ("ELG") Rule and Section 316(b) of the Clean Water Act.

Q. What has Tampa Electric calculated as the actual/estimated true-up for the current period to be applied.

A. The actual/estimated true-up applicable for the current period, January 2018 through December 2018, is an over-recovery of $13,472,483. A detailed calculation supporting the true-up amount is shown on Forms 42-1E through 42-9E of my exhibit.

Q. Is Tampa Electric including costs in the actual/estimated true-up filing for any new environmental projects that were not anticipated and included in its 2018 ECRC factors?

A. Yes, Tampa Electric included costs associated with the company's compliance with Section 316(b) of the Clean Water Act. The company's petition for approval to recover such costs through the ECRC was filed on April 26, 2018. In addition, new costs for compliance with the ELG Rule are included. The company's petition for approval to recover such costs through the ECRC was filed on May 9, 2018. The respective petitions explain the need for the projects and the regulations requiring those activities. The testimony of Tampa Electric witness Paul L. Carpinone submitted concurrently in this docket also supports these projects.

Q. What depreciation rates were utilized for the capital projects contained in the 2018 actual/estimated true-up?

A. Tampa Electric utilized the depreciation rates approved in Order No. PSC-2012-0175-PAA-EI, issued on April 3, 2012, in Docket No. 20110131-EI, with two exceptions. For the Big Bend Fuel Oil Tank No. 1 Upgrade and Big Bend Fuel Oil Tank No. 2 Upgrade projects, the company has utilized depreciation rates calculated to recover the remaining net investment balances of these now-retired assets from July 2018 through December 2021, which represents a five-year period from the date of their retirement on December 31, 2016. Tampa Electric requests approval for this treatment as it is consistent with Commission-approved treatment for other assets retired before the end of their projected depreciable life over a five-year period from the date of retirement. For example, the accelerated recovery of the remaining net investment balance of the Gannon Ignition Oil Tank project over a five-year period was authorized by Commission Order No. PSC-2000-2391-FOF-EI, issued December 13, 2000 in Docket No. 20000007-EI.

Q. Why were the assets of the Big Bend Fuel Oil Tank No. 1 Upgrade and Big Bend Fuel Oil Tank No. 2 Upgrade projects retired earlier than expected?

A. The assets were retired December 31, 2016 after an analysis of the expenses to maintain them and consideration of the low utilization of oil at the station after the Big Bend igniters on Units 1 through 4 were converted to natural gas operation. In 2016, the maintenance cost to bring the 4.5 million-gallon tank system to current standards was estimated at $1.5 million. Annual monitoring and reporting costs were approximately $50,000 to $75,000. In light of these substantial costs and the fact that oil use at the station was greatly reduced after the igniters conversion in 2015, so that a large amount of oil storage was no longer needed, Tampa Electric retired the assets. With the retirement, Tampa Electric was no longer required to fill the tank with now-unneeded amounts of No. 2 fuel oil at the start of each hurricane season to prevent the tank from floating in the event of storm related flooding. Finally, retiring the tank avoided the continued environmental costs and risks of managing a tank of this size in proximity to the waters of the State.

Q. What capital structure, components and cost rates did Tampa Electric rely on to calculate the revenue requirement rate of return for January 2018 through December 2018?

A. Tampa Electric's revenue requirement rate of return for January 2018 through December 2018 is calculated based on the capital structure, components and current period cost rates as approved in Order No. PSC-2012-0425-PAA-EU, issued on August 16, 2012 in Docket No. 20120007-EI. The calculation of the revenue requirement rate of return is shown on Form 42-9E.

Q. Has Tampa Electric adjusted the revenue requirements of its ECRC capital projects to reflect the lower tax rate of 21 percent in the Tax Cuts and Jobs Act of 2017 ("TCJA")?

A. Yes, the company updated the tax multiplier utilized in the determination of the equity component of the revenue requirement rate of return, shown on Form 42-9E, Document

No. 9 of my Exhibit No. PAR-2.

Q. Did the company apply the lower tax rate in the calculation of revenue requirements for its ECRC capital projects for the period January 2018 through December 2018?

A. Yes. Tampa Electric calculated the new tax multiplier and revised rate of return in early 2018 and began applying the rate to the monthly ECRC net investment balances in May 2018. The company calculated an adjustment to reflect revenue requirements with the lower tax rate for the months of January 2018 through April 2018 and booked the adjustment, including interest, in May 2018. This tax adjustment effectively identified and recorded the difference in the amount of allowed cost recovery for environmental projects due to the lower tax rate as an over-recovery for the first four months of 2018 that will be considered as part of the company's projected overall over- or under-recovery for the year.

Form 42-8E, which is included as Document No. 8 of Exhibit No. PAR-2, shows the calculation of the adjusted monthly revenue requirements for capital projects using the lower tax rate and revised rate of return for the January through December 2018 period.

Q. Will the company account for the flowback of excess accumulated deferred income taxes associated with environmental projects in this docket or as part of Docket No. 20180045-EI, which addresses the overall impact of the TCJA on the company?

A. The flowback of excess accumulated deferred income taxes associated with environmental projects recovered through the environmental cost recovery clause is being addressed in Docket No. 20180045-EI and does not need to be considered in this docket.

Q. How did the actual/estimated project expenditures for the January 2018 through December 2018 period compare with the company's original projections?

A. As shown on Form 42-4E, total O&M costs are expected to be $9,400,732 less than the amount that was originally projected. The total capital expenditures itemized on Form 42-6E, are expected to be $4,523,890 less than originally projected. Significant variances for O&M costs and capital project amounts are explained below.

O&M Project Variances

O&M expense projections related to planned maintenance work are typically spread across the period in question. However, the company always inspects the units to ensure that the maintenance is needed, before beginning work. The need varies according to the actual usage and associated "wear and tear" on the units. If inspection indicates that the maintenance is not yet needed or if additional work is needed, then the company will have a variance compared to the projection. When inspections indicate that work is not needed now, that maintenance expense will be incurred in a future period when warranted by the condition of the unit.

- **Big Bend Unit 3 Flue Gas Desulfurization ("FGD") Integration:** The Bend Unit 3 FGD Integration Project variance is estimated to be $2,529,108 or 57.2 percent less than projected due to greater operation on natural gas, compared to the original projection. This reduces the expected need for consumables and maintenance.

- **Big Bend Units 1 & 2 FGD:** The Big Bend Units 1 & 2 FGD project variance is estimated to be $1,629,196 or 74.1 percent less than projected. The variance is due to lower costs for consumables and maintenance than expected as the units burned natural gas.

- **Big Bend PM Minimization & Monitoring:** The Big Bend PM Minimization & Monitoring Project variance is estimated to be $204,721 or 33.5 percent lower than projected. This variance is due to less maintenance being required than expected, after inspection.

- **Big Bend NO_x Emissions Reduction:** The Big Bend NO_x Emissions Reduction project variance is $60,263 or 43.4 percent less than projected. This variance is due to the operation of Big Bend Units 1 & 2 on natural gas.

- **Bayside Selective Catalytic Reduction ("SCR") Consumables:** The Bayside SCR Consumables project variance is estimated to be $92,779 or 45.5 percent less than projected. This variance is due to less total run time estimated for Bayside Station units, compared to the original projection, resulting in less ammonia consumption.

- **Clean Water Act Section 316(b) Phase II Study Program:** The Clean Water Act Section 316(b) Phase II Study Program project variance is $246,842 or 76.9 percent less than projected. The National Pollutant Discharge

Elimination System ("NPDES") permit renewal for Big Bend Station has not yet been finalized. The variance is related to uncertainty regarding the timing of the final requirements and reporting that must be submitted once the permit is finalized.

- **Big Bend Unit 1 SCR:** The Big Bend Unit 1 SCR project variance is $1,147,483 or 76.6 percent less than originally projected. This variance is due to operation of the unit on natural gas, which reduced the unit's need for consumables and maintenance work, compared to the original projection.

- **Big Bend Unit 2 SCR:** The Big Bend Unit 2 SCR project variance is $1,268,864 or 77.8 percent less than originally projected. This variance is due to operation of the unit on natural gas, which reduced the use of consumables and need for maintenance work, compared to the original projection.

- **Big Bend Unit 3 SCR:** The Big Bend Unit 3 SCR project variance is $141,390 or 8.3 percent less than projected. This variance is due to greater operation on natural gas, compared to the original projection.

- **Big Bend Unit 4 SCR:** The Big Bend Unit 4 SCR project variance is $410,017 or 38.6 percent less than projected. This variance is due to less total run time estimated when compared to the original projection.

- **Mercury Air Toxics Standards:** The Mercury Air Toxics Standards project variance is $206,622 or 89.4 percent less than projected. Both Polk and Big Bend Power Stations achieved Low Emitting Electric Generating Unit status in 2017. As a result, monitoring is not required at this time, only periodic testing, and the costs were lower than originally projected.

- **Big Bend ELG Rule Study:** The Big Bend ELG Study project variance is $54,007 greater than projected. This variance is due to a delay in completing the study, compared to the original projection. The study has now been completed.

- **CCR Rule – Phase II:** The Big Bend Coal Combustion Residual ("CCR") Rule Phase II project variance is $1,367,762 or 22.3 percent less than projected. This variance is due to timing differences in the project schedule when compared to the original projection. Dewatering activities, which must occur before the CCR disposal, have occurred more slowly than originally projected. The project expenditures are still needed and will be incurred in the future.

Capital Project Variances

There were significant capital variances for the projects listed below, each of which was due to the TCJA tax rate change from 35 percent to 21 percent.

- Big Bend Unit 3 Flue Gas Desulfurization ("FGD") Integration
- Big Bend Units 1 & 2 FGD
- BIG Bend FGD Optimization and Utilization
- Big Bend NOx Emissions Reduction
- Big Bend Particulate Matter Minimization
- Big Bend Unit 1 SCR
- Big Bend Unit 2 SCR
- Big Bend Unit 3 SCR
- Big Bend Unit 4 SCR
- Big Bend FGD System Reliability
- Mercury Air Toxics Standards
- Big Bend Gypsum Storage Facility
- CCR Rule – Phase I

As I stated earlier, Tampa Electric updated the tax multiplier utilized in the determination of the equity component of the revenue requirement rate of return and applied the lower tax rate in the calculation of revenue requirements for the ECRC capital projects for the period January 2018 through December 2018.

Q. Does this conclude your direct testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180001-EI
FILED: 08/24/2018

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 N. 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. Have you previously filed testimony in Docket No. 20180001-EI?

A. Yes, I submitted direct testimony on March 2, 2018 and July 27, 2018.

Q. Has your job description, education, or professional experience changed since then?

A. No, it has not.

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 for January 2019 through December 2019. I 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 2019.

Q. Have you prepared an exhibit to support your direct 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 2019 through December 2019 as well as Schedule H1 for 2016 through 2019. Document No. 3 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate, which demonstrates that the tiered rate is revenue neutral. Document No. 4 presents the capital costs and fuel savings for the company projects that have been approved 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 $17,124,796 after jurisdictional separation, prior year true-up, and application of the revenue tax factor, for estimated expenses in 2019.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2019 through December 2019.

A.

Rate Class and Metering Voltage	**Capacity Cost Cents per kWh**	**Recovery Factor $ per Kw**
RS Secondary	0.103	
GS and CS Secondary	0.086	
GSD, SBF Standard		
Secondary		0.32
Primary		0.32
Transmission		0.31
IS, IST, SBI		
Primary		0.24
Transmission		0.24
GSD Optional		
Secondary	0.075	
Primary	0.074	
Transmission	0.074	
LS1 Secondary	0.024	

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 0.088 cents per kWh compare to the factor for January 2018 through December 2018?

A. The proposed capacity cost recovery factor is 0.032 cents per kWh (or $0.32 per 1,000 kWh) higher than the average capacity cost recovery factor of 0.056 cents per kWh for the January 2018 through December 2018 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 2019?

A. The appropriate amount for the 2019 period is 2.719 cents per kWh before the application of the 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 2019 through December 2019.

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 penalty of $2,261,019, 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 to be applied during the January 2019 through December 2019 period. The net true-up amount is an over-recovery of $7,015,485.

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 2019 through December 2019. The schedule also presents Tampa Electric's levelized fuel cost factors at each metering level.

Q. Please describe the information presented 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 2019 through December 2019.

A.

Metering Voltage Level	**Fuel Charge Factor (Cents per kWh)**
Secondary	2.719
Tier I (Up to 1,000 kWh)	2.405
Tier II (Over 1,000 kWh)	3.405
Distribution Primary	2.692
Transmission	2.665
Lighting Service	2.691
Distribution Secondary	2.874 (on-peak)
	2.653 (off-peak)

Metering Voltage Level	**Fuel Charge Factor (Cents per kWh)**
Distribution Primary	2.845 (on-peak)
	2.626 (off-peak)
Transmission	2.817 (on-peak)
	2.600 (off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor 2.719 cents per kWh compare to the levelized fuel adjustment factor for the January 2018 through December 2018 period?

A. The proposed fuel charge factor is 0.413 cents per kWh (or $4.13 per 1,000 kWh) lower than the average fuel charge factor of 3.132 cents per kWh for the January 2018 through December 2018 period.

Capital Projects Approved for Fuel Clause Recovery

Q. What did Tampa Electric calculate as the estimated Big Bend Units 1-4 ignition oil conversion project costs for the period January 2019 through December 2019?

A. The estimated Big Bend Units 1-4 ignition oil conversion project capital costs, including depreciation and return, are $4,462,045. This is shown in Exhibit No. PAR-3, Document No. 4.

Q. Does Tampa Electric's estimated Big Bend Units 1-4 ignition oil conversion project fuel savings exceed costs for the period January 2019 through December 2019?

A. Yes, fuel savings exceed costs for the period January 2019 through December 2019. This information is also presented in Exhibit No. PAR-3, Document No. 4.

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 2019 through December 2019 estimated fuel savings are greater than the projected 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-2014-0309-PAA-EI, issued in Docket No. 20140032-EI on June 12, 2014.

Q. Please describe the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for this project.

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 and Optimization Mechanism

Q. Will Tampa Electric project a 2019 wholesale incentive benchmark that is derived in accordance with Order No. PSC-2001-2371-FOF-EI issued in Docket No. 20010283-EI?

A. No. Effective January 1, 2018, as authorized by FPSC Order No. PSC-2017-0456-S-EI, issued in Docket No. 20160160-EI on November 27, 2017, the company's Optimization Mechanism replaced the existing short-term wholesale sales incentive mechanism, and as a result no incentive benchmark is required for the 2019 projection. Under the new program, gains on all optimization mechanism activities, including short-term wholesale sales, short-term wholesale purchases, and all forms of asset optimization undertaken each year will be shared between shareholders and customers. The sharing thresholds are (a) for the first $4.5 million per year, 100 percent of gains to customers; (b) for gains greater than $4.5 million per year and less than $8.0 million per year, split 60 percent to shareholders and 40 percent to customers; and (c) for gains greater than $8.0 million per year, 50-50 sharing between shareholders and 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 $8.31 beginning January 2019, when compared to the September 2018 through December 2018 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 2019.

Q. Does this conclude your direct 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, Unit Commitment.

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 am a registered Professional Engineer in the state of Florida, and I have over 20 years of electric utility work experience. I began my career with Tampa Electric in 1999 as an Engineer in Plant Technical Services and have held various engineering positions at Tampa Electric's power generating stations and in the Operations

Planning Department where I was responsible for unit performance analysis and reporting. In 2008, I was promoted to Manager, Operations Planning, and in 2011, NERC Compliance was added to my current responsibilities. In 2017, I was promoted to Manager, Unit Commitment, where I am responsible for portfolio optimization of Tampa Electric’s generation assets.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is (i) 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 2017 through December 2017 and compare them to the targets for the period; (ii) present corrected actual performance results and targets for the years 2014, 2015, and 2016; and (iii) present corrected targets for the years 2017 and 2018.

Q. Have you prepared exhibits to support your testimony?

A. Yes, for the 2017 performance results, I prepared Exhibit No. BSB-1, consisting of two documents. Document No. 1, entitled “GPIF Schedules” is consistent with the GPIF Implementation Manual approved by the Commission. Document No. 2 provides the company's Actual Unit Performance Data for the 2017 period.

Exhibit No. BSB-2, consisting of eight documents, is provided to correct actual results and targets. Exhibit No. BSB-2 comprises the following documents:

Document No. 1	January 2014 – December 2014 Targets
Document No. 2	January 2014 – December 2014 Actual Performance Results
Document No. 3	January 2015 – December 2015 Targets
Document No. 4	January 2015 – December 2015 Actual Performance Results
Document No. 5	January 2016 – December 2016 Targets
Document No. 6	January 2016 – December 2016 Actual Performance Results
Document No. 7	January 2017 – December 2017 Targets
Document No. 8	January 2018 – December 2018 Targets

Q. Which generating units on Tampa Electric's system are included in the determination of the 2017 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 2017 through December 2017 period?

A. Yes, I have. This is shown on Exhibit No. BSB-1, Document No. 1, page 4 of 32. Based upon -5.548 Generating Performance Incentive Points ("GPIP"), the result is a penalty amount of $4,711,929 for the period.

Q. Please proceed with your review of the actual results for the January 2017 through December 2017 period.

A. On Exhibit No. BSB-1, Document No. 1, page 3 of 32, the actual average common equity for the period is shown on line 14 as $2,489,302,804. This produces the maximum penalty or reward amount of $8,493,208 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 Exhibit No. BSB-1, 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, 576.0 planned outage hours were originally scheduled for 2017. Actual outage activities required 144.0 planned outage hours. Consequently, the actual equivalent availability of 71.1 percent is adjusted to 67.5 percent as shown on Exhibit No. BSB-1, Document No. 1, page 7 of 32.

Big Bend Unit No. 2

On this unit, 576.0 planned outage hours were originally scheduled for 2017. Actual outage activities required 650.7

planned outage hours. Consequently, the actual equivalent availability of 58.3 percent is adjusted to 58.8 percent as shown on Exhibit No. BSB-1, Document No. 1, page 8 of 32.

Big Bend Unit No. 3

On this unit, 1,920.0 planned outage hours were originally scheduled for 2017. Actual outage activities required 309.5 planned outage hours. Consequently, the actual equivalent availability of 49.8 percent is adjusted to 40.3 percent as shown on Exhibit No. BSB-1, Document No. 1, page 9 of 32.

Big Bend Unit No. 4

On this unit, 576.0 planned outage hours were originally scheduled for 2017. Actual outage activities required 0.0 planned outage hours. Consequently, the actual equivalent availability of 69.3 percent is adjusted to 64.7 percent as shown on Exhibit No. BSB-1, Document No. 1, page 10 of 32.

Polk Unit No. 1

On this unit, 648.0 planned outage hours were originally scheduled for 2017. Actual outage activities required 381.6 planned outage hours. Consequently, the actual equivalent availability of 90.5 percent is adjusted to 87.6 percent, as shown on Exhibit No. BSB-1, Document No. 1, page 11 of 32.

Bayside Unit No. 1

On this unit, 1,631.0 planned outage hours were originally scheduled for 2017. Actual outage activities required 1,015.7 planned outage hours. Consequently, the actual equivalent availability of 86.5 percent is adjusted to 79.7 percent, as shown on Exhibit No. BSB-1, Document No. 1, page 12 of 32.

Bayside Unit No. 2

On this unit, 1,705.0 planned outage hours were originally scheduled for 2017. Actual outage activities required 820.8 planned outage hours. Consequently, the actual equivalent availability of 85.5 percent is adjusted to 75.9 percent, as shown on Exhibit No. BSB-1, 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 Exhibit No. BSB-1, 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 Exhibit No. BSB-1, 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 2017 through December 2017 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, -5.548, is then located in the GPIF table on page 2 of 32, and the penalty amount of $4,711,929 is calculated using linear interpolation.

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 $8,493,208, as shown in Exhibit No. BSB-1, Document No. 1, pages 2 and 3.

Q. Is Tampa Electric proposing any adjustment to previously filed GPIF exhibits?

A. Yes, Tampa Electric proposes to make an adjustment to correct errors in Bayside Station gas consumption that affect 2014, 2015, and 2016 actual results and targets, as well as 2017 and 2018 targets. The company discovered the error while analyzing Bayside unit heat rates that appeared too high and corrected the 2017 actual results in its monthly performance data filings. The corrected actual results and targets are shown in Exhibit No. BSB-2, Document Nos. 1 through 8.

Q. Please describe the data error and the efforts to prevent such an error in the future.

A. The data error occurred because of the manner in which natural gas consumption at Bayside Station was calculated. A common gas pipeline serves both Bayside and Big Bend Power Stations. The Big Bend Station consumption was determined by metered data, and the Bayside Station consumption was calculated as the total gas volume flow on the pipeline from FGT and Gulfstream, less the Big Bend Station consumption. In September 2012, the Maydell gate was installed on the pipeline serving Bayside and Big Bend Power stations to provide natural gas to a truck filling station. From September 2012 until August 2017, the Maydell gate consumption was not subtracted from Bayside Station's gas consumption. As a result, Bayside natural gas consumption was overstated. The truck filling station consumption was relatively small in the early years (2012-2013); however, consumption increased over time (2014-present), resulting in material impacts to the Bayside heat rates and GPIF results. As a result, Tampa Electric corrected the previously reported consumption and Bayside heat rate calculations for GPIF results for the period from January 2014 through December 2016.

To ensure that this error does not occur in the future, changes in the determination of Bayside Station consumption have been made. Rather than a calculated consumption, effective October 2017, actual daily MMBtu data for Bayside Station is being measured by the Gas Measurement & Regulation Department. Along with the meter measurement of Bayside Station consumption, additional control check and reconciliation have been established to validate data and identify and address meter issues. First, a weekly reconciliation of the gas pipeline volumes is now being performed by the Gas Supply Department. Second, a plant measurement to pipeline measurement comparison is performed weekly by the Asset Management Department. The change in Bayside Station consumption determination along with the checks and reconciliation identified above will prevent this error from occurring in the future.

Q. Why does a consumption data error require restatement of targets?

A. GPIF targets are set annually, based on the previous three years of historical data. Therefore, the data errors affected not only the actual heat rate results the company reported, but also the targets set using that data.

Q. Is the 2017 penalty calculated using the company’s corrected 2017 targets?

A. Yes, the $4,711,929 penalty was calculated by comparing actual performance results for 2017 to the corrected 2017 targets submitted in Exhibit No. BSB-2.

Q. Please describe the impacts of the Bayside consumption error correction to GPIF results for 2014, 2015, and 2016.

A. The original filed GPIF amounts, corrected values, and annual differences for the 2014 through 2016 GPIF reward/penalty amounts are shown in the following table:

	Difference in GPIF Reward/(Penalty)		
	Original	Corrected	Difference
2014	$1,258,599	$1,990,038	$731,439
2015	969,593	1,711,713	742,120
2016	47,392	1,024,743	977,351
Total			$2,450,910

Q. Did you make any other changes to the data in the corrected schedules shown in Exhibit No. BSB-2?

A. Yes, I made a change to the company's GPIF targets for January 2018 through December 2018, shown in Document No. 8 of my Exhibit No. BSB-2. I updated the tax rate used in the determination of the maximum reward associated with the GPIF target to reflect the lower corporate tax rate specified by the Tax Cuts and Jobs Act of 2017, enacted by the United States Congress on December 20, 2017 and signed into law by the President on December 22, 2017. The lower tax rate is effective January 1, 2018, so it applies to the 2018 targets.

Q. Are the schedules shown in your exhibit consistent with the GPIF manual approved by the Commission?

A. Yes, the 2017 actual results provided in Exhibit No. BSB-1, as well as the revised actual results and targets provided in Exhibit No. BSB-2, are correct and were prepared in accordance with the Commission-approved GPIF Implementation Manual.

Q. What is the net impact to GPIF from the 2017 actual performance results and the correction in Bayside Station consumption for years 2014 through 2016?

A. The net result of the $4,711,929 penalty for 2017 actual performance results and the 2014 through 2016 corrections is a penalty of $2,261,019 for 2017.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

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

Q. Have you previously filed testimony in Docket No. 20180001-EI?

A. Yes, I submitted direct testimony on March 15, 2018.

Q. Has your job description, education, or professional experience changed since then?

A. No, it has not.

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 an exhibit to support your direct testimony?

A. Yes. Exhibit BSB-3, 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 2019 period.

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

A. Four natural gas combined cycle units are included. These are Polk Units 1 and 2 and Bayside Units 1 and 2.

Q. Do the exhibits you prepared comply with the 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 2019 through

December 2019 represent 83 percent of the total forecasted system net generation for this period.

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-2006-1057-FOF-EI issued in Docket No. 20060001-EI on December 22, 2006.

Q. Did Tampa Electric identify any outages as outliers?

A. No.

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.

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

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2019 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 four units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2019 period, the projected EUOF for Bayside Unit 1 is 1.9 percent, and the POF is 7.1 percent. Therefore, the target EAF for Bayside Unit 1 equals 91.0 percent or:

$$100\% - (1.9\% + 7.1\%) = 91.0\%$$

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 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. Calculating the maximum incentive points, a 20 percent reduction in EUOF, plus a five percent reduction in the POF is necessary. Continuing with the Bayside Unit 1 example:

$$EAF_{MAX} = 1 - [0.80\ (1.9\%) + 0.95\ (7.1\%)] = 91.7\%$$

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

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

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

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

Again, continuing using the Bayside Unit 1 example,

$$EAF_{MIN} = 1 - [1.40\ (1.9\%) + 1.10\ (7.1\%)] = 89.5\%$$

The equivalent availability maximum and minimum for the other three 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 2019 are shown on page 15 of Document No. 1. There are not any major outages of 28 days or greater planned for the GPIF units during 2019; therefore, no Critical Path Method diagrams are provided. However, Planned Outage Factors are calculated for each unit. For example, Bayside Unit 1 is scheduled for a planned outage from February 1, 2019 to February 13, 2019 and November 14, 2019 to November 23, 2019. There are 624 planned outage hours scheduled for the 2019 period, with a total of 8,760 hours during this 12-month period. Consequently, the POF for Bayside Unit 1 is 7.1 percent or:

$$\frac{624}{8,760} \times 100\% = 7.1\%$$

The factor for each unit is shown on pages 5 and 11 through 14 of Document No. 1. Polk Unit 1 has a POF of 8.2 percent. Polk Unit 2 has a POF of 6.6 percent. Bayside Unit 1 has a POF of 7.1 percent, and Bayside Unit 2 has a POF of 7.7 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 1.9 percent for Bayside Unit 1. The EUOF of Bayside Unit 1 is verified by the data shown on page 13, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

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

Or

$$EUOF = \frac{(84 + 83)}{8{,}760} \times 100\% = 1.9\%$$

Relative to Bayside Unit 1, the EUOF of 1.9 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Polk Unit 1

The projected EUOF for this unit is 8.5 percent. The unit will have two planned outages in 2019, and the POF is 8.2 percent. Therefore, the target equivalent availability for this unit is 83.3 percent.

Polk Unit 2

The projected EUOF for this unit is 2.5 percent. The unit will have two planned outages in 2019, and the POF is 6.6

percent. Therefore, the target equivalent availability for this unit is 90.9 percent.

Bayside Unit 1

The projected EUOF for this unit is 1.9 percent. The unit will have two planned outages in 2019, and the POF is 7.1 percent. Therefore, the target equivalent availability for this unit is 91.0 percent.

Bayside Unit 2

The projected EUOF for this unit is 4.9 percent. The unit will have two planned outages in 2019, and the POF is 7.7 percent. Therefore, the target equivalent availability for this unit is 87.4 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 86.5 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 1 on page 13 of Document No. 1. Except for the months of February and November, the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled for these months. During the months of February and November, the Equivalent Unplanned Outage Rate exceeds the Equivalent Unplanned Outage Factor due to the 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 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 are the targets determined?

A. Net heat rate data for the three most recent July through June annual periods form the basis for 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 period 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 or 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 21 through 24 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 the 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 2019 period.

A. The heat rate target for Polk Unit 1 is 10,170 Btu/Net kWh with a range of ± 937 Btu/Net kWh. The heat rate target for Polk Unit 2 is 6,930 Btu/Net kWh with a range of ± 173 Btu/Net kWh. The heat rate for Bayside Unit 1 is 7,400 Btu/Net kWh with a range of ± 116 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,561 Btu/Net kWh with a range of ± 228 Btu/Net kWh. A zone of tolerance of ± 75 Btu/Net kWh is included within a range for each target. This is shown on page 4, and pages 7 through 10 of Document No. 1.

Q. Do the heat rate targets and ranges in Tampa Electric's projection meet the criteria of the GPIF 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 10. 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 $446,098,430 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 the individual savings are calculated, column 4 totals $10,838,700 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 1, the weighting factor for average net operating heat rate is 14.0 percent as shown in the right-hand column on page 6. Pages 7 through 10 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 1, page 9, if the unit operates at 7,284 average net operating heat rate, fuel savings would equal $1,517,065 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 10. 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 $10,838,700. 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 2019 is $2,999,881,612. This produces the maximum allowed jurisdictional incentive of $10,071,700 shown on line 21.

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

A. Yes. As Order No. PSC-2013-0665-FOF-EI issued in Docket No. 20130001-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 $5,419,348.

Q. Please summarize your direct 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).

$$\begin{aligned} GPIP = (&0.0507\ EAP_{PK1} + 0.0190\ EAP_{PK2} \\ &+ 0.0111\ EAP_{BAY1} + 0.0312\ EAP_{BAY2} \\ &+ 0.1057\ HRP_{PK1} + 0.3689\ HRP_{PK2} \\ &+ 0.1400\ HRP_{BAY1} + 0.2735\ HRP_{BAY2}) \end{aligned}$$

Where:

GPIP = Generating Performance Incentive Points

EAP = Equivalent Availability Points awarded/deducted for Polk Units 1 and 2, and Bayside Units 1 and 2

HRP = Average Net Heat Rate Points awarded/deducted for Polk Units 1 and 2, and Bayside Units 1 and 2

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2019 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 direct testimony?

A. Yes, it does.

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 Wholesale Marketing & Fuels 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, Gas and Power Origination in the Wholesale Marketing, Planning and Fuels Department. My responsibilities are to evaluate short and long-term power purchase and sale opportunities within the wholesale power market, assist in wholesale power and gas transportation origination and contract structures, and assist in combustion by-product contract administration and market opportunities. 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. 20030001-EI, 20040001-EI, and 20080001-EI regarding the appropriateness and prudence of Tampa Electric's wholesale purchases and sales.

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

A. The purpose of my testimony is to provide a description of Tampa Electric's purchased power 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-1997-0262-FOF-EI, issued in Docket No. 19970001-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 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 2018 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 nine percent of the company’s expected needs for 2018 will be met using purchased power. This includes economy energy purchases, purchases from qualifying facilities, pre-existing firm purchased power agreement with Pasco Cogen and reliability purchases.

My testimony in previous years' dockets described the agreement with Pasco Cogen. However, in summary, the Pasco Cogen purchase is a call option with dual-fuel (*i.e.*, natural gas or oil) capability. The Pasco Cogen purchase began January 2009, is for 121 MW of combined-cycle capacity and continues through 2018. The Pasco Cogen purchase agreement was previously approved by the Commission as being cost-effective for Tampa Electric customers.

Q. Has Tampa Electric entered into any other wholesale power purchases in 2018?

A. Yes. Tampa Electric purchased forward up to 250 MW of economic energy for the period May through October. The purchases are on-peak, must-take products from Florida Power & Light ("FPL") and ExGen. The FPL purchase volume is for 50 MW in May and 150 MW from June through October. The ExGen purchase is 100 MW during the period of May through October. These purchases are expected to result in $1.25 million of total savings to customers.

Q. Does Tampa Electric anticipate entering into new wholesale power purchases for 2019 and beyond?

A. Yes, the company anticipates entering into new short-term power purchases for 2019. Tampa Electric will continue to evaluate its options in light of changing circumstances and new opportunities. This evaluation includes the review of short- and long-term capacity and energy purchases to augment its own generation for the year 2019 and beyond with purchases that bring value to customers. Currently, Tampa Electric expects purchased power to meet approximately eight percent of its 2019 energy needs.

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 power agreement is from a dual-fuel resource. This allows the resource to run on either natural gas or oil, which enhances supply reliability during a potential hurricane-related disruption in natural gas supply. Absent the threat of a hurricane, and for all other months of the year, the company evaluates economic combinations of short- and long-term purchase opportunities in the market place.

Q. Please describe Tampa Electric's wholesale energy sales for 2018 and 2019.

A. Tampa Electric entered into various non-separated wholesale sales in 2018, and the company anticipates making additional non-separated sales during the balance of 2018 and 2019. The gains from these sales are distributed amongst Tampa Electric and its customers in accordance with the company's current optimization mechanism, which is described in the testimony of Tampa Electric witness J. Brent Caldwell, submitted concurrently in this docket.

Q. Please summarize your direct 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 physical forward and spot wholesale power markets to provide customers with a reliable supply at the lowest possible cost. In addition to the cost benefits, this purchased power approach employs a diversified physical power supply strategy that enhances reliability. The company also enters into wholesale sales that benefit customers when market conditions allow.

Q. Does this conclude your direct 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 Portfolio Optimization.

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 2017, I assumed responsibility for Portfolio Optimization which includes unit commitment, near-term maintenance planning, and natural gas and wholesale power trading.

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. 20150001-EI regarding natural gas hedging. I have also testified before the Commission in Docket No. 20120234-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 2017 results of Tampa Electric's risk management activities, as required by the terms of the stipulation entered into by the parties to Docket No. 20011605-EI and approved by the Commission in Order No. PSC-2002-1484-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 2017

Hedging Activity True-up, was prepared under my direction and supervision. This report describes the company's risk management activities and results for the calendar year 2017.

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.

Natural Gas Financial Hedging

Q. Please describe the natural gas financial hedging moratorium that began in 2016 and its effects on 2017 risk management activities.

A. On October 24, 2016, electric investor-owned utilities DEF, Gulf and Tampa Electric, collectively the IOUs, Office of Public Counsel, the Florida Industrial Power Users Group, and the Florida Retail Federation jointly entered into a Stipulation and Agreement ("Agreement").

Under the terms of the Agreement, the IOUs agreed to put in place a 100 percent moratorium on any new hedges, effective immediately upon the Commission's approval of the Agreement, with that moratorium extending through calendar year 2017. The Agreement was approved by the Commission on December 5, 2016, with the issuance of Order No. PSC-2016-0547-FOF-EI. By Commission vote memorialized in Order No. PSC-2017-0134-PCO-EI issued April 13, 2017, Tampa Electric was not required to file a 2018 Risk Management Plan, effectively extending the hedging moratorium.

Tampa Electric prudently followed its 2016 Risk Management Plan, Commission Order No. PSC-2016-0547-FOF-EI, and Commission Order No. PSC-2017-0134-PCO-EI in utilizing financial hedges already in place prior to the moratorium to mitigate volatility of natural gas prices during the period January 2017 through December 2017.

Q. What does Tampa Electric plan to do when the hedging moratorium ends?

A. In accordance with the company’s 2017 Amended and Restated Stipulation and Settlement Agreement approved by Commission Order No. PSC-2017-0456-S-EI, issued on

November 27, 2017 in Docket No. 20170210-EI, Tampa Electric will not enter into any new natural gas financial hedging contracts for fuel from January 1, 2018 through December 31, 2022.

Q. Does Tampa Electric have any natural gas financial hedging contracts that were entered prior to the start of the hedging moratorium?

A. Yes. Tampa Electric continues to report on the natural gas financial hedging contracts entered prior to Commission approval of the hedging moratorium, and the company has not entered any new financial hedging contracts since the moratorium began.

Risk Management Activities

Q. What were the results of Tampa Electric's risk management activities in 2017?

A. As outlined in Tampa Electric's 2017 Hedging Activity True-up, filed as an exhibit to this testimony, the company followed a non-speculative risk management strategy to reduce fuel price volatility while maintaining a reliable supply of fuel. The company's 2017 risk management activities include financial hedges established prior to the moratorium. Tampa Electric’s 2017 natural gas hedging activities resulted in a net settlement gain of approximately $2.6 million. These results are due to the market conditions experienced in the past year as natural gas prices increased in 2017 due to reduced drilling in response to previous low natural gas prices coupled with increased natural gas demand from new liquified natural gas facilities. The 2017 financial hedges were successful in achieving the risk management 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 physically hedges its supply using 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, Tampa Electric uses the Allegro System (“Allegro”). 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. Allegro tracks all existing financial natural gas hedging transactions, and the system produces risk management reports.

Q. Did the company use financial hedges for commodities other than natural gas in 2017?

A. No. Tampa Electric did not use financial hedges for commodities other than natural gas in 2017. Tampa

Electric’s generation units are fueled primarily by 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, 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 obtains 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 Commission Order No. PSC-2002-1484-FOF-EI, in Docket No. 20011605-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.

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, Portfolio Optimization.

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, natural gas procurement and transportation, fuel logistics and cost reporting, long-term fuel supply planning and procurement, and business systems analysis. In July 2017, I assumed responsibility for Portfolio Optimization which includes unit commitment, near-term maintenance planning and natural gas and wholesale power trading.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor and describe my Exhibit No. JBC-2, entitled Tampa Electric Natural Gas Hedging Activities, January 1, 2018 through July 31, 2018.

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 shows details of Tampa Electric's hedging activities for natural gas for the seven-month period January 2018 through July 2018. All hedging transactions were entered into prior to the start of the ongoing financial natural gas hedging moratorium.

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, Portfolio Optimization.

Q. Have you previously filed testimony in Docket No. 20180001-EI?

A. Yes, I submitted direct testimony on April 3, 2018 and August 10, 2018.

Q. Has your job description, education, or professional experience changed since your most recent testimony?

A. No, it has not.

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. 20150001-EI on the subject of natural gas hedging. I have also testified before the Commission in Docket No. 20120234-EI regarding the company's fuel procurement for the Polk 2-5 Combined Cycle ("CC") Conversion project. Most recently, I submitted written testimony in Docket No. 201700057-EI regarding natural gas financial hedging.

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.

Fuel Mix and Procurement Strategies

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

A. Tampa Electric's fuel mix includes natural gas, coal, solar, and oil as a backup fuel. The Big Bend units can operate on coal or natural gas. Polk Unit 2 CC uses natural gas as a primary fuel and oil as a secondary fuel; and Bayside Station combined cycle units and the company's collection of peakers (*i.e.*, aero-derivative combustion turbines) all utilize natural gas. Since it serves as a backup fuel, oil consumption as a percentage of system generation is negligible. During 2018, continued low natural gas prices haves resulted in greater use of natural gas, compared to the original projection. Based upon the 2018 actual-estimate projections, the company expects 2018 total system generation to be 83 percent natural gas and 16 percent coal. The remainder of the 2018 projected generation will be from solar facilities, at approximately 1 percent.

In 2019, natural gas-fired and coal-fired generation are expected to be approximately 88 percent and 7 percent of total generation, respectively. The remaining 5 percent of 2019 projected generation will be from solar facilities.

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

A. Tampa Electric emphasizes flexibility and options in its fuel procurement strategy for all its fuel needs. The company strives to maintain a large number of credit worthy 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 flexibility to pursue lower cost options for Tampa Electric customers.

Coal Supply Strategy

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

A. The steam turbine units at Big Bend Station are designed to burn high-sulfur Illinois Basin coal and fully scrubbed for sulfur dioxide and nitrogen oxides, and the units have been upgraded to operate on natural gas. Polk Unit 1 can burn a mix of petroleum coke, low sulfur coal or natural gas. Each plant has varying operational and environmental restrictions and requires solid fuel with custom quality characteristics such as ash content, fusion temperature, sulfur content, heat content, and chlorine content.

Coal is not a homogenous product. The fuel's chemistry and contents vary based on many factors, including geography. The variability of the product dictates Tampa Electric select its fuel based on multiple parameters. Those parameters include unique coal characteristics, price, availability, deliverability, and credit worthiness 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 generation 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. This market intelligence also helps shape 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. In addition, this strategy allows the company the flexibility to take advantage of favorable spot market opportunities and address operational needs.

Q. Please summarize how Tampa Electric will manage its solid fuel supply contracts through 2019.

A. Since the company will use less coal and more natural gas in 2019 compared to previous years, Tampa Electric will supply the Big Bend and Polk Stations with solid fuel through a combination of existing inventory, 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.

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. 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 2018 and 2019?

A. Yes. Tampa Electric expects to receive coal for use at Big Bend Station through the Big Bend rail facility during 2018 and is evaluating how much coal to receive by rail in 2019.

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

A. Tampa Electric expects to receive solid fuel supply from 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. Do you have any other updates to provide with regard to Tampa Electric's solid fuel transportation portfolio?

A. Tampa Electric's "open" positions for solid fuel, rail and Gulf transportation, along with other operational and market factors, allows the company to use more natural gas in the dual-fueled Big Bend and Polk units, when economical. As a result, Tampa Electric will contract for fewer tons of solid fuel supply and Gulf transportation in the remainder of 2018 and 2019 than it would have otherwise.

Q. Please describe any other significant factors that Tampa Electric considered in developing its 2019 solid fuel supply portfolio.

A. Tampa Electric continues to place emphasis on flexibility in its solid fuel supply portfolio. The company recognizes that several factors may impact the annual consumption of solid fuel. 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 supplies 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 and seasonal 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.

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

A. Tampa Electric currently receives natural gas via the Florida Gas Transmission ("FGT") and Gulfstream Natural Gas System, LLC ("Gulfstream") pipelines. Tampa Electric has added the ability to receive a portion of its gas via the recently constructed Sabal Trail Transmission ("Sabal Trail") gas pipeline. The ability to deliver natural gas directly from three 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 from Gulfstream and Sabal Trail (via Gulfstream backhaul) to support the aero-derivative combustion turbines and steam generating units. Polk Station receives natural gas from FGT to support Polk Unit 2 CC and, as an alternate fuel, Polk Unit 1. The addition of Sabal Trail to the list of delivery options enhances reliability and supply price diversity.

Q. Are there any significant changes to Tampa Electric's expected natural gas usage?

A. Tampa Electric's Big Bend Station coal-fired units can be fueled with natural gas for ignition, reliability, emissions control, and power generation. As such, Tampa Electric is seeking to utilize its existing pipeline capacity and is burning natural gas to the extent that there is available capacity and it is the more economic option. Over the past few years, Tampa Electric's natural gas usage has increased, and that trend is expected to continue in 2019 due to expected low natural gas prices. The low natural gas prices along with the flexibility the company has built into its units, coal supply and transportation portfolio positions, and available natural gas pipeline capacity has allowed the company to take advantage of alternate fuel opportunities. This strategy lowers overall costs.

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. In alignment with this objective, effective April 1, 2018, the company has reserved 2,000,000 MMBtu of long-term storage capacity from two salt-dome storage caverns that replaced the previous storage capacity at a single location.

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 Transco lateral capacity give Tampa Electric access to secure, competitively priced on-shore gas supply for a portion of its portfolio.

Q. Has Tampa Electric acquired additional natural gas transportation for 2018 and 2019 due to greater use of natural gas?

A. Yes, with the continued low price of natural gas and the company’s growing demand for natural gas for electric generation purposes, the company acquires daily, seasonal and, recently, longer-term pipeline capacity to support the company’s portfolio of gas-fired generation assets. In particular, in 2018 Tampa Electric acquired 20,000 MMBtu per day of pipeline capacity on Sabal Trail. This capacity provides additional diversification of pipelines and gas supply receipt points.

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-term, 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.

Q. Have there been other changes in the management of Tampa Electric's fuel supply portfolio?

A. Yes, as part of Tampa Electric's 2017 Amended and Restated Stipulation and Settlement Agreement approved by Commission Order No. PSC-2017-0456-S-EI, issued on November 27, 2017 in Docket No. 20170210-EI, Tampa Electric has been operating under an Asset Optimization Mechanism since January 1, 2018. This Optimization Mechanism encourages Tampa Electric to market temporarily unused fuel supply assets to capture cost mitigation benefits for customers. These benefits have come through economic power purchases, economic power sales, resale of unneeded fuel supply, and utilization of natural gas storage and transportation assets.

Q. Are additional activities envisioned to generate additional benefits through the Optimization Mechanism?

A. Yes, Tampa Electric expects to generate additional benefits through an Asset Management Agreement ("AMA") for the natural gas storage capacity assets.

Q. Please describe what an AMA is.

A. In general, an AMA is an agreement between an entity that has the contractual rights to an asset and a market participant that optimizes the use of that asset to serve the entity's needs and to use that asset for market activity. The entity with the contractual right and the Asset Manager share in the benefit derived from the optimization activity. The AMA supports the extraction of additional value for an entity by utilizing the expertise of the Asset Manager to combine its asset portfolio and market access with the use of the AMA assets.

Q. Please describe the AMA Tampa Electric is implementing.

A. As previously mentioned, Tampa Electric has 2,000,000 MMBtu of natural gas storage capacity contracted between two storage facilities. Tampa Electric is contracting with Emera Energy Services ("EES") to optimize 1,500,000 MMBtu of that capacity. Tampa Electric is retaining all of its rights to store and withdraw natural gas in that capacity, and EES has the right to utilize the portion that is not being used by Tampa Electric. EES has guaranteed a minimum level of benefit and then will share transactional benefits above that amount with Tampa Electric. The AMA is effective from September 1, 2018.

Q. How was EES chosen to be the Asset Manager?

A. Tampa Electric conducted a request for proposals to manage the storage assets. Two entities were short-listed and offered the opportunity to refine their offer. Ultimately, EES provided the greatest guaranteed benefits for customers.

Projected 2019 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, the Energy Information Administration, and other energy market information sources. Future prices for energy commodities as traded on NYMEX, averaged over five consecutive business days in April 2018, form the basis of the natural gas and No. 2 oil market commodity price forecasts. The price projections for these two commodities are then adjusted to incorporate expected transportation costs and location differences.

Coal prices and coal transportation prices are projected using contracted pricing and information from industry recognized consultants and published indices. 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 2019 projected fuel prices compare to the fuel prices projected for 2018?

A. The commodity price for natural gas during 2019 is projected to be lower ($2.79 per MMBtu) than the 2018 price ($3.13 per MMBtu) projected when setting the 2018 fuel cost recovery clause factors. The 2019 coal commodity price projection is slightly higher ($37.57 per ton) than the price projected for 2018 ($35.80 per ton) during preparation of the 2018 fuel clause factors. The significant volume of natural gas produced in association with crude oil production from shale continues to keep natural gas prices low. While low natural gas prices are keeping downward pressure on coal prices, access to the higher valued international market is putting upward pressure on coal prices.

Risk Management Activities

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

A. The ongoing Tampa Electric moratorium on natural gas financial hedges was continued in 2018 by Commission approval of the company's 2017 Amended and Restated Stipulation and Settlement Agreement memorialized in Order No. PSC-2017-0456-S-EI, issued on November 27, 2017 in Docket No. 20170210-EI. The agreement states that Tampa Electric will not enter into any new natural gas financial hedging contracts for fuel from January 1, 2018 through December 31, 2022.

Tampa Electric continues to report on the natural gas financial hedging contracts entered prior to Commission approval of the hedging moratorium, and the company has not entered any new financial hedging contracts since the moratorium began.

Q. Were Tampa Electric's efforts through July 31, 2018 to mitigate price volatility through its non-speculative hedging program prudent?

A. Yes. On April 3, 2018, the company filed its 2017 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 31st 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 in this docket on August 10, 2018. The report shows the results of the company's prudent hedging activities, for hedges in place prior to the start of the hedging moratorium, from January through July 2018.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF SIMON O. OJADA

DOCKET NO. 20180001-EI

SEPTEMBER 14, 2018

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. 20130001-EI, 20140001-EI, 20150001-EI, 20160001-EI and 20170001-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff auditor's report of Duke Energy Florida, LLC (DEF or Utility) which addresses the Utility's filing in Docket No. 20180001-EI, Fuel and Purchased Power Cost Recovery Clause, for costs associated with its hedging activities. We issued an auditor's report in this docket for the hedging activities on August 31, 2018. This 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 by me.

Q. Please describe the work performed in this audit.

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

<u>Accounting Treatment</u>

We obtained DEF's supporting detail of the hedging settlements for the 12 months ended July 31, 2018. The support documentation was reconciled to the general ledger transaction detail. We verified that the accounting treatment for hedging transactions and transaction costs is consistent with Commission orders relating to hedging activities. The Utility did not enter into any new contracts between August 1, 2017 and July 31, 2018. No exceptions were noted.

<u>Gains and Losses</u>

We reconciled the monthly balances of hedging transactions from DEF's Hedging Details Report for the period August 1, 2017, through July 31, 2018, to its Hedging Summary by Commodity Reports for 2017 and 2018. We reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. We selected 22 natural gas hedging transactions from August 2017 through July 2018 as a sample. We reconciled the selected samples from the Hedging Details Report to the third-party confirmation notices and contracts. We reconciled the gains and losses to the Utility's journal entries. We 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

We reviewed the quantity limits and authorizations for all hedged fuel types. The Utility did not file a Risk Management Plan in 2017 or 2018. No exceptions were noted.

Separation of Duties

We reviewed the Utility's procedures for separating duties related to hedging activities. We reviewed the Utility Audit Services Department's evaluations for the 12 months ending December 31, 2017, for the Regulated Fuels Inventory Management Process and the Regulated Trading Cycle. There was no external audit on hedging activities during the test period. No exceptions were noted.

Q. Please review the audit findings in this 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 DEBRA M. DOBIAC

DOCKET NO. 20180001-EI

SEPTEMBER 14, 2018

Q. Please state your name and business address.

A. My name is Debra M. Dobiac. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida, 32399.

Q. By who are you presently employed?

A. I am employed by the Florida Public Service Commission (FPSC or Commission) in the Office of Auditing and Performance Analysis. I have been employed by the Commission since January 2008.

Q. Please describe your current responsibilities.

A. Currently, I am a Public Utility Analyst with the responsibilities of managing regulated utility financial audits. I am also responsible for creating audit work programs to meet a specific audit purpose.

Q. Briefly review your educational and professional background.

A. I graduated with honors from Lakeland College in 1993 and have a Bachelor of Arts degree in accounting. Prior to my work at the Commission, I worked for six years in internal auditing at the Kohler Company and First American Title Insurance Company. I also have approximately 12 years of experience as an accounting manager and controller.

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

A. Yes. I testified in the Aqua Utilities Florida, Inc. Rate Case, Docket No. 20080121-WS, the Water Management Services, Inc. Rate Case, Docket No. 20110200-WU, and the Utilities, Inc. of Florida Rate Case, Docket No. 20160101-WS. I also provided testimony for the Water Management Services, Inc. Rate Case, Docket No. 20100104-WU, the Gulf Power Company Rate Cases, Docket Nos. 20110138-EI and 20130140-EI, and the Gulf Power Company Hedging Activities, Docket Nos. 20130001-EI and 20140001-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff auditor's report of Florida Power & Light Company (FPL or Utility) which addresses the Utility's filing in Docket No. 20180001-EI, Fuel and Purchased Power Cost Recovery Clause, for costs associated with its hedging activities. We issued an auditor's report in this docket for the hedging activities on August 23, 2018. This report is filed with my testimony and is identified as Exhibit DMD-1.

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

A. Yes, it was prepared by me.

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 five months ended December 31, 2017. The support documentation was traced to the general ledger transaction detail. We verified that the accounting treatment for hedging transactions and transactions costs are consistent with Commission orders relating to hedging activities. We noted that there was no hedging activity from January to July 2018 as required by Order No. 2016-0560-AS-EI, issued December 15, 2016. No exceptions were noted.

<u>Gains and Losses</u>

We traced the monthly balances of hedging transactions from FPL's April 3, 2018 Hedging Information Report filed in this docket for the period August 1, 2017, to December 31, 2017 to FPL's Derivative Settlement Reports. We selected a sample of hedging transactions from various counterparties from September and December 2017 for natural gas and traced them from the Derivative Settlement Report to the invoices, purchase statements, confirmation notices and deal tickets. We compared a sample of the purchase prices to the Gas Daily – NYMEX Henry Hub gas futures contract rates. We traced the floating price to the Settlement Price worksheet and to the Gas Daily – NMEX Henry Hub gas futures contract rates provided by the Utility. We recalculated the gains and losses. We compared the recalculated gains and losses with the FPL's journal entries for realized gains and losses. FPL does not have any tolling agreements where natural gas is provided to generators under purchased power agreements. FPL did not have any physical hedging instruments in its August 1, 2017 to July 31, 2018 hedging activities. 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 natural gas hedged in relation to natural gas burned for the five months ended December 31, 2017, and compared them with the Utility's 2016 Risk Management Plan. The Utility did not file a Risk Management Plan in 2017 or 2018. No exceptions were noted.

<u>Separation of Duties</u>

We reviewed the Utility's procedures for separating duties related to hedging activities. We verified the separation of duties during our testing of transactions by agreeing the names of various employees from deal tickets and confirmations to FPL's procedures. We requested internal and external audits that related to hedging activities for the period August 1, 2017 to July 31, 2018. The Utility stated there were none. 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, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF DONNA D. BROWN

DOCKET NO. 20180001-EI

SEPTEMBER 14, 2018

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 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 Science 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 testified in Florida Power & Light Company Storm Recovery Cost Audit – Hurricane Matthew, Docket No. 20160251-EI. I filed testimony in the Fuel and Purchased Power Cost Recovery Clause, Docket Nos. 20110001-EI, 20120001-EI and 20160001-EI, the Gulf Power Rate Case, Docket No. 20160186-EI, and the Florida Power & Light Company Hedging Activities, Docket No. 20170001-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff auditor's report of Gulf Power Company (Gulf or Utility) which addresses the Utility's filing in Docket No. 20180001-EI, Fuel and Purchased Power Cost Recovery Clause, for costs associated with its hedging activities. We issued an auditor's report in this docket for the hedging activities on August 30, 2018. This report is filed with my testimony and is identified as Exhibit DDB-1.

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

A. Yes, it was prepared by me.

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

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

Accounting Treatment

We obtained Gulf's supporting detail of the hedging settlements for the twelve months ended July 31, 2018. 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. The Utility did not enter into any new contracts between August 1, 2017 and July 31, 2018. No exceptions were noted.

Gains and Losses

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, 2017 to July 31, 2018. 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 GPC's analysis of the monthly percent of natural gas hedged in relation to natural gas burned for the twelve months ended July 31, 2018, and compared them with the Utility's 2016 Risk Management Plan. The Utility did not file a Risk Management Plan in 2017 or 2018. No exceptions were noted.

Separation of Duties

We reviewed the Utility's procedures for separating duties related to hedging activities. We requested internal and external audit reports from August 1, 2017 to July 31, 2018 and noted that none pertained to the fuel hedging program. No exceptions were noted.

Q. Please review the audit findings in this 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

COMMISSION STAFF

DIRECT TESTIMONY OF INTESAR TERKAWI

DOCKET NO. 20180001-EI

SEPTEMBER 14, 2018

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.

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. 20140001-EI, 20150001-EI, 20160001-EI and 20170001-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff auditor's report of Tampa Electric Company (TECO or Utility) which addresses the Utility's filing in Docket No. 20180001-EI, Fuel and Purchased Power Cost Recovery Clause, for costs associated with its hedging activities. We issued an auditor's report in this docket for the hedging activities on August 31, 2018. This 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 by me.

Q. Please describe the work performed in this audit.

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

<u>Accounting Treatment</u>

We obtained TECO's supporting detail of the hedging settlements for the twelve months ended July 31, 2018. The supporting documentation was traced to the general ledger transaction detail. We verified that the accounting treatment for hedging transactions and transaction costs are consistent with Commission orders relating to hedging activities. The Utility did not enter into any new contracts between August 1, 2017 and July 31, 2018. No exceptions were noted.

<u>Gains and Losses</u>

We 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, 2017, to July 31, 2018. We selected all gas hedging transactions for September and October 2017 and traced them from the Mark to Market Position Report to the third-party confirmation notices and contracts. We traced a sample of the purchase prices to the Gas Daily – NYMEX Henry Hub gas futures contract rates. We traced the related settlements prices to the Gas Daily – NYMEX Henry Hub gas futures contract rate. We 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

We reviewed the quantity limits and authorizations. We also obtained TECO's analysis of the monthly percent of fuel hedged in relation to fuel burned for the year ended July 31, 2018, and compared them to the Utility's 2016 Risk Management Plan. The Utility did not file a Risk Management Plan in 2017 or 2018. No exceptions were noted.

Separation of Duties

We 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 report.

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

Q. Does this conclude your testimony?

A. Yes.

(Transcript continues in sequence in Volume 3.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court 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 7th day of November, 2018.

____
DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #GG015952
EXPIRES JULY 27, 2020