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FPSC - COMMISSION CLERK

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 140001-EI

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

VOLUME 2

Pages 234 through 438

PROCEEDINGS: HEARING

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

DATE: Wednesday, October 22, 2014

TIME: Commenced at 9:50 a.m.
Concluded at 11:04 a.m.

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

REPORTED BY: LINDA BOLES, CRR, RPR
Official FPSC Reporter
(850) 413-67340

APPEARANCES: (As heretofore noted.)

WITNESSES

EXHIBITS

NUMBER:	ID.	ADMTD.
1 through 68 (as identified in Comprehensive Exhibit List)	348	
1 through 18 and 24A through 68 19 through 24	348	348
69 RRSSA Excerpt		421
70 DEF Summary of NEIL Reimbursement	390	
71 Fuel Cost Recovery Schedules	390	
72 (Late-Filed) Amount of Estimated Carrying Charges	436	

P R O C E E D I N G S

(Transcript continues in sequence following Volume 1.)

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 Administrator, Rates in the Regulatory Affairs Department.

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

A. I received a Bachelor of Arts degree in Economics from the University of New Orleans in 1995, and I received a Master of Arts degree in Economics from the University of South Florida in Tampa in 1997. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, where I have assumed positions of increasing responsibility in the areas of fuel and capacity cost recovery. I have accumulated 17 years of electric utility experience working in the areas of load forecasting, cost recovery clauses, as well as project management and rate setting activities for wholesale and retail rate cases. My duties include managing cost recovery for fuel and purchased power, interchange sales, and capacity payments.

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 2013 through December 2013 for the Fuel and Purchased Power Cost Recovery Clause ("Fuel Clause"), the Capacity Cost Recovery Clause ("Capacity Clause") as well as the wholesale incentive benchmark for January 2014 through December 2014.

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 2013 through December 2013?

A. The final true-up amount for the Capacity Clause for the period January 2013 through December 2013 is an under-recovery of $8,074.

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 2013 Through December 2013", provides the calculation for the final under-recovery of $8,074. The actual capacity cost under-recovery, including interest, was $599,839 for the period January 2013 through December 2013 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the $591,765 actual/estimated under-recovery approved in Order No. PSC-13-0665-FOF-EI issued December 18, 2013 in Docket No. 130001-EI, results in a final under-recovery of $8,074 for the period, as identified in Document No. 1, page 4 of 4. This under-recovery amount will be applied in the calculation of the capacity cost recovery factors for the period January 2015 through December 2015.

Q. What is the estimated effect of this $8,074 under-recovery for the January 2013 through December 2013 period on residential bills during January 2015 through December 2015?

A. The $8,074 under-recovery will increase a 1,000 kWh residential bill by approximately $0.001.

Fuel and Purchased Power Cost Recovery Clause

Q. What is the final true-up amount for the Fuel Clause for the period January 2013 through December 2013?

A. The final Fuel Clause true-up for the period January 2013 through December 2013 is an over-recovery of $23,552,208. The actual fuel cost over-recovery, including interest, was $39,182,755 for the period January 2013 through December 2013. This $39,182,755 amount, less the $15,630,547 actual/estimated over-recovery amount approved in Order No. PSC-13-0665-FOF-EI, issued December 18, 2013 in Docket No. 130001-EI, results in a net over-recovery amount for the period of $23,552,208.

Q. What is the estimated effect of the $23,552,208 over-recovery for the January 2013 through December 2013 period on residential bills during January 2015 through December 2015?

A. The $23,552,208 over-recovery will decrease a 1,000 kWh residential bill by approximately $1.28.

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 2013 Through December 2013". It shows the calculation of the final fuel over-recovery of

$23,552,208.

Line 1 shows the total company fuel costs of $710,706,692 for the period January 2013 through December 2013. The jurisdictional amount of total fuel costs is $710,706,692, 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 $38,240,545 over-recovered fuel costs for the period, interest, true-up collected and the prior period true-up shown on lines 5 through 8 respectively, constitute the actual over-recovery of $39,182,755 shown on line 9. The $39,182,755 actual over-recovery amount less the $15,630,547 actual/ estimated over-recovery amount shown on line 10, results in a final $23,552,208 over-recovery amount for the period January 2013 through December 2013 as shown on line 11.

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

A. Document No. 3 is entitled "Tampa Electric Company Calculation of True-up Amount Actual *vs.* Original Estimates for the Period January 2013 Through December

2013." 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 2013 through December 2013?

A. As shown on line A7 of Document No. 3, the fuel and net power transaction cost is $34,627,264 less than the amount originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2013 through December 2013?

A. As shown on line C3 of Document No. 3, the company collected $3,266,163, or 0.4 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 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. In 2013, Tampa Electric began to recover the capital costs for the Polk Unit 1 project through the fuel clause, in accordance with Order No. PSC-12-0498-PAA-EI issued September 27, 2012 in Docket No. 120153-EI.

Wholesale Incentive Benchmark

Q. What is Tampa Electric's wholesale incentive benchmark for 2014, as derived in accordance with Order No. PSC-01-2371-FOF-EI, Docket No. 010283-EI?

A. The company's 2014 benchmark is $681,121, which is the three-year average of $902,388, $246,931 and $894,045 actual gains on non-separated wholesale sales, excluding emergency sales, for 2011, 2012 and 2013, respectively.

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 140001-EI
FILED: 7/25/2014

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 received a Bachelor of Arts degree in Economics from the University of New Orleans in 1995, and I received a Master of Arts degree in Economics from the University of South Florida in Tampa in 1997. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, where I have assumed positions of increasing responsibility in the areas of fuel and capacity cost recovery. I have accumulated 17 years of electric utility experience working in the areas of load forecasting, cost recovery clauses, as well as project management and rate setting activities for wholesale and retail rate cases. My duties include managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and FPSC-approved environmental projects.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2014 through December 2014 fuel and purchased power and capacity actual/estimated true-up amounts to be recovered in the January 2015 through December 2015 projection period. My testimony addresses the recovery of fuel and purchased power costs as well as capacity costs for the year 2014, based on six months of actual data and six months of estimated data. This information will be used in the determination of the 2015 fuel and purchased power costs and capacity cost recovery factors.

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

A. Yes. I have prepared Exhibit No. ____ (PAR-2), which consists of three documents. Document No. 1 includes Schedules E1-B, E-2, E-3, E-4, E-5, E-6, E-7, E-8, and E-9, which provide the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2014 through December 2014. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period of January 2014 through December 2014. Document No. 3 provides the actual/estimated Polk Unit 1 ignition oil conversion project capital costs and fuel savings for the period of January 2014 through December 2014 as well as the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for the project. These documents are furnished as support for the projected true-up amount for this period.

Fuel and Purchased Power Cost Recovery Factors

Q. What has Tampa Electric calculated as the estimated net true-up amount for the current period to be applied in the January 2015 through December 2015 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount applicable for the period January 2015 through December 2015 is an over-recovery of $13,386,207.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2015 through December 2015 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2015 is the sum of the final true-up amount for the period January 2013 through December 2013 and the actual/estimated true-up amount for the period January 2014 through December 2014.

Q. What did Tampa Electric calculate as the final fuel and purchased power cost recovery true-up amount for 2013?

A. The final true-up was an over-recovery of $23,552,208. The actual fuel cost over-recovery, including interest was $39,182,755 for the period January 2013 through December 2013. The $39,182,755 amount, less the actual/estimated over-recovery amount of $15,630,547 approved in Order No. PSC-13-0665-FOF-EI, issued December 18, 2013 in Docket No. 130001-EI resulted in a net over-recovery amount for the period of $23,552,208.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery true-up amount for the period January 2014 through December 2014?

A. The actual/estimated fuel and purchased power cost recovery true-up is an under-recovery amount of $10,166,001 for the January 2014 through December 2014 period. The detailed calculation supporting the actual/estimated current period true-up is shown in Exhibit No. ____ (PAR-2), Document No. 1 on Schedule E1-B.

Capacity Cost Recovery Clause

Q. What has Tampa Electric calculated as the estimated net true-up amount to be applied in the January 2015 through December 2015 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January 2015 through December 2015 is an under-recovery of $33,526 as shown in Exhibit No. ____ (PAR-2), Document No. 2, page 2 of 5.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2015 through December 2015 capacity cost recovery factors?

A. The net true-up amount to be recovered in the 2015 capacity cost recovery factors is the sum of the final true-up amount for 2013 and the actual/estimated true-up amount for January 2014 through December 2014.

Q. What did Tampa Electric calculate as the final capacity cost recovery true-up amount for 2013?

A. The final 2013 true-up is an under-recovery of $8,074. The actual capacity cost under-recovery including interest was $599,839 for the period January 2013 through December 2013. This amount, less the $591,765 actual/estimated under-recovery amount approved in Order No. PSC-13-0665-FOF-EI issued December 18, 2013 in Docket No. 130001-EI results in a net under-recovery amount for the period of $8,074 as identified in Exhibit No. ____ (PAR-2), Document No. 2, page 1 of 5.

Q. What did Tampa Electric calculate as the actual/estimated capacity cost recovery true-up amount for the period January 2014 through December 2014?

A. The actual/estimated true-up amount is an under-recovery of $25,452 as shown on Exhibit No. ____ (PAR-2), Document No. 2, page 1 of 5.

Polk Unit 1 Ignition Oil Conversion

Q. What did Tampa Electric calculate as the actual/estimated

Polk Unit 1 ignition oil conversion project costs for the period January 2014 through December 2014?

A. The actual/estimated Polk Unit 1 ignition oil conversion project capital costs, including depreciation and return, for the period of January 2014 through December 2014 are $4,429,920. This is shown in Exhibit No. ____ (PAR-2), Document No. 3. In addition, the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for the Polk Unit 1 ignition oil conversion project are shown in Document No. 3.

Q. What did Tampa Electric calculate as the actual/estimated Polk Unit 1 ignition oil conversion project fuel savings for the period January 2014 through December 2014?

A. The actual/estimated fuel savings for the period January 2014 through December 2014 are $19,332,410, which exceeds the actual/estimated capital costs by $14,902,490, as shown in Exhibit No. ___ (PAR-2), Document No. 3.

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

A. Yes. The January 2014 through December 2014 actual/estimated fuel savings are greater than the project capital costs, providing an expected net benefit to customer, and the costs are eligible for recovery through the fuel clause in accordance with FPSC Order No. PSC-12-0498-PAA-EI, issued in Docket No. 120153-EI on September 27, 2012.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PENELOPE A. RUSK

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

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

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

A. I received a Bachelor of Arts degree in Economics from the University of New Orleans in 1995, and I received a Master of Arts degree in Economics from the University of South Florida in Tampa in 1997. I joined Tampa Electric in 1997, as an Economist in the Load Forecasting Department. In 2000, I joined the Regulatory Affairs Department, where I have assumed positions of increasing responsibility in the areas of fuel and capacity cost recovery. I have accumulated 17 years of electric utility experience working in the areas of load forecasting, cost recovery clauses, as well as project management and rate setting activities for wholesale and retail rate cases. My duties include managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and FPSC-approved environmental projects.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, the proposed annual levelized fuel and purchased power cost recovery factors including an inverted or two-tiered residential fuel charge to encourage energy efficiency and conservation and the projected wholesale incentive benchmark for January 2015 through December 2015. I will also describe significant events that affect the factors and provide an overview of the composite effect on the residential bill of changes in the various cost recovery factors for 2015.

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

A. Yes. Exhibit No. ____ (PAR-3), consisting of four documents, was prepared under my direction and supervision. Document No. 1, consisting of four pages, is furnished as support for the projected capacity cost recovery factors. Document No. 2, which is furnished as support for the proposed levelized fuel and purchased power cost recovery factors, includes Schedules E1 through E10 for January 2015 through December 2015 as well as Schedule H1 for January through December, 2012 through 2015. Document No. 3 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate and a levelized fuel rate, which demonstrates that the tiered rate is revenue neutral. Document No. 4 presents the capital costs and related fuel savings for the company’s projects that have been approved for recovery through the fuel clause, as well as the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for the projects.

Capacity Cost Recovery

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

A. Yes. The capacity cost recovery factors, prepared under my direction and supervision, are provided in Exhibit No. ____ (PAR-3), Document No. 1, page 3 of 4.

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

A. Tampa Electric is requesting recovery of capacity payments for power purchased for retail customers, excluding optional provision purchases for interruptible customers, through the capacity cost recovery factors. As shown in Exhibit No. ____ (PAR-3), Document No. 1, Tampa Electric requests recovery of $31,972,087 after jurisdictional separation and prior year true-up, for estimated expenses in 2015.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2015 through December 2015.

A.

Rate Class and Metering Voltage	Capacity Cost Cents per kWh	Recovery Factor $ per kW
RS Secondary	0.204	
GS and TS Secondary	0.183	
GSD, SBF Standard		
Secondary		0.63

Primary		0.62
Transmission		0.62
IS, IST, SBI		
Primary		0.41
Transmission		0.40
GSD Optional		
Secondary	0.147	
Primary	0.146	
LS1 Secondary	0.025	

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 0.172 cents per kWh compare to the factor for January 2014 through December 2014?

A. The proposed capacity cost recovery factor is the same as the average capacity cost recovery factor of 0.172 cents per kWh for the January 2014 through December 2014 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 2015?

A. The appropriate amount for the 2015 period is 3.874 cents per kWh before the application of time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. ____ (PAR-3), Document No. 2, shows the appropriate value for the total fuel and purchased power cost recovery factor for each metering voltage level as projected for the period January 2015 through December 2015.

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

A. The Generating Performance Incentive Factor ("GPIF") and true-up factors are provided on Schedule E1-C. Tampa Electric has calculated a GPIF reward of $1,689,728, which is included in the calculation of the total fuel and purchased power cost recovery factors. In addition, Schedule E1-C indicates the net true-up amount for the January 2014 through December 2014 period. The net true-up amount for this period is an over-recovery of $13,386,207.

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 2015 through

December 2015. The schedule also presents Tampa Electric's levelized fuel cost factors at each metering voltage level.

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

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

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

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

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for January 2015 through December 2015.

A.

Metering Voltage Level	**Fuel Charge Factor (cents per kWh)**
Secondary	3.874
Tier I (Up to 1,000 kWh)	3.559
Tier II (Over 1,000 kWh)	4.559
Distribution Primary	3.835
Transmission	3.797
Lighting Service	3.830
Distribution Secondary	4.114 (on-peak)
	3.772 (off-peak)
Distribution Primary	4.073 (on-peak)
	3.734 (off-peak)
Transmission	4.032 (on-peak)
	3.697 (off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 3.874 cents per kWh compare to the levelized fuel adjustment factor for the January 2014 through December 2014 period?

A. The proposed fuel charge factor is 0.036 cents per kWh (or $0.36 per 1,000 kWh) lower than the average fuel charge factor of 3.910 cents per kWh for the January 2014 through December 2014 period.

Events Affecting the Projection Filing

Q. Are there any significant events reflected in the calculation of the 2015 fuel and purchased power and capacity cost recovery projections?

A. Yes. There is one significant event reflected in the 2015 projections: the inclusion of Big Bend Units 1-4 Igniters Conversion capital costs, which is more than offset by the anticipated fuel savings of the project. The Commission approved the recovery of the estimated depreciation and return costs for the Big Bend conversion project in FPSC Order No. PSC-14-0309-PAA-EI, issued in Docket No. 140032-EI on June 12, 2014. The costs are shown in Document No. 4 of my exhibit, and described below.

Capital Projects Approved for Fuel Clause Recovery

Q. What did Tampa Electric calculate as the estimated Polk Unit 1 ignition oil conversion project costs for the period January 2015 through December 2015?

A. The estimated Polk Unit 1 ignition oil conversion project capital costs, including depreciation and return, for the period of January 2015 through December 2015 are $4,114,495. This is shown in Exhibit No. _____ (PAR-3), Document No. 4.

Q. What did Tampa Electric calculate as the estimated Polk Unit 1 ignition oil conversion project fuel savings for the period January 2015 through December 2015?

A. The estimated fuel savings for the period January 2015 through December 2015 are $5,950,084, which exceeds the estimated capital costs by $1,835,588, as shown in Exhibit No. _____ (PAR-3), Document No. 4.

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

A. Yes. The January 2015 through December 2015 estimated fuel savings are greater than the project capital costs, providing an expected net benefit to customer, and the costs are eligible for recovery through the fuel clause in accordance with FPSC Order No. PSC-12-0498-PAA-EI, issued in Docket No. 120153-EI on September 27, 2012.

Q. What did Tampa Electric calculate as the estimated Big Bend Units 1-4 ignition oil conversion project costs for the period January 2015 through December 2015?

A. The estimated Big Bend Units 1-4 ignition oil conversion project capital costs, including depreciation and return, for the period of January 2015 through December 2015 are $3,310,090. This is shown in Document No. 4 of my exhibit.

Q. What did Tampa Electric calculate as the estimated Big Bend Units 1-4 ignition oil conversion project fuel savings for the period January 2015 through December 2015?

A. The estimated fuel savings for the period January 2015 through December 2015 are $3,639,503, which exceeds the estimated capital costs by $329,413. This information is also presented in Document No. 4 of my exhibit.

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

A. Yes. The January 2015 through December 2015 estimated fuel savings are greater than the project capital costs, providing an expected net benefit to customer, and the costs are eligible for recovery through the fuel clause in accordance with FPSC Order No. PSC-14-0309-PAA-EI, issued in Docket No. 140032-EI on June 12, 2014.

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

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

Wholesale Incentive Benchmark Mechanism

Q. What is Tampa Electric’s projected wholesale incentive benchmark for 2015?

A. The company’s projected 2015 benchmark is $1,403,580, which is the three-year average of $246,932, $894,045 and $3,069,762 in gains on the company’s non-separated wholesale sales, excluding emergency sales, for 2012, 2013 and 2014 (actual/estimated), respectively.

Q. Does Tampa Electric expect gains in 2015 from non-separated wholesale sales to exceed its 2015 wholesale incentive benchmark?

A. No. Tampa Electric anticipates that sales will not exceed the projected benchmark for 2015. Therefore, all sales margins are expected to flow back to customers.

Cost Recovery Factors

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

A. The composite effect on a residential bill for 1,000 kWh is a decrease of $1.22 beginning January 2015, when compared to the January 2014 through October 2014 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 2015.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 140001-EI
FILED: 03/7/2014

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

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

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

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Tampa Electric's actual performance results from unit equivalent availability and heat rate used to determine the Generating Performance Incentive Factor ("GPIF") for the period January 2013 through December 2013. I will also compare these results to the targets established prior to the beginning of the period.

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

A. Yes, I prepared Exhibit No. _____ (BSB-1), consisting of two documents. Document No. 1, entitled "Tampa Electric Company, Generating Performance Incentive Factor, January 2013 - December 2013 True-up" is consistent with the GPIF Implementation Manual previously approved by the Commission. Document No. 2 provides the company's Actual Unit Performance Data for the 2013 period.

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

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

Q. Have you calculated the results of Tampa Electric's performance under the GPIF during the January 2013 through December 2013 period?

A. Yes, I have. This is shown on Document No. 1, page 4 of 32. Based upon 2.071 Generating Performance Incentive Points ("GPIP"), the result is a reward amount of $1,689,728 for the period.

Q. Please proceed with your review of the actual results for the January 2013 through December 2013 period.

A. On Document No. 1, page 3 of 32, the actual average common equity for the period is shown on line 14 as $1,995,749,538. This produces the maximum penalty or reward amount of $8,157,103 as shown on line 21.

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

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

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

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

Big Bend Unit No. 1

On this unit, 576.0 planned outage hours were originally scheduled for 2013. Actual outage activities required 950.1 planned outage hours. Consequently, the actual equivalent availability of 71.5 percent is adjusted to 74.9 percent as shown on Document No. 1, page 7 of 32.

Big Bend Unit No. 2

On this unit, 576.0 planned outage hours were originally scheduled for 2013. Actual outage activities required 531.2 planned outage hours. Consequently, the actual equivalent availability of 75.6 percent is adjusted to 75.2 percent as shown on Document No. 1, page 8 of 32.

Big Bend Unit No. 3

On this unit, 1,847.0 planned outage hours were originally scheduled for 2013. Actual outage activities required 2,188.3 planned outage hours. Consequently, the actual equivalent availability of 66.5 percent is adjusted to 70.0 percent as shown on Document No. 1, page 9 of 32.

Big Bend Unit No. 4

On this unit, 576.0 planned outage hours were originally scheduled for 2013. Actual outage activities required 422.1 planned outage hours. Consequently, the actual equivalent availability of 77.6 percent is adjusted to 76.1 percent as shown on Document No. 1, page 10 of 32.

Polk Unit No. 1

On this unit, 841.0 planned outage hours were originally scheduled for 2013. Actual outage activities required 1,337.2 planned outage hours. Consequently, the actual equivalent availability of 79.6 percent is adjusted to 85.0 percent, as shown on Document No. 1, page 11 of 32.

Bayside Unit No. 1

On this unit, 432.0 planned outage hours were originally scheduled for 2013. Actual outage activities required 334.6 planned outage hours. Consequently, the actual equivalent availability of 88.6 percent is adjusted to 87.7 percent, as shown on Document No. 1, page 12 of 32.

Bayside Unit No. 2

On this unit, 480.0 planned outage hours were originally scheduled for 2013. Actual outage activities required 357.4 planned outage hours. Consequently, the actual equivalent availability of 83.7 percent is adjusted to 82.5 percent, as shown on Document No. 1, page 13 of 32.

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

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

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

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

Q. What is the overall GPIP for Tampa Electric for the January 2013 through December 2013 period?

A. This is shown on Document No. 1, page 2 of 32. Essentially, the weighting factors shown on page 4 of 32, column 3, plus the equivalent availability points and the heat rate points shown on page 4 of 32, column 4, are substituted within the equation found on page 32 of 32. The resulting value, 2.071, is then entered into the GPIF table on page 2 of 32. Using linear interpolation, the reward amount is $1,689,728.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 140001-EI
FILED: 08/22/2014

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BRIAN S. BUCKLEY

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

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

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

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

Q. What is the purpose of your testimony?

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

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

A. Yes, Exhibit No. ____ (BSB-2), consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2015 period.

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

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

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

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

Q. Did Tampa Electric identify any outages as outliers?

A. Yes. Big Bend Unit 3, Big Bend Unit 4 and Bayside Unit 1 outages were identified as outlying outages; therefore, the associated forced outage hours were removed from the study.

Q. Did Tampa Electric make any other adjustments?

A. Yes. As allowed per Section 4.3 of the GPIF Implementation Manual, the Forced Outage and Maintenance Outage Factors were adjusted to reflect recent unit performance and known unit modifications or equipment changes.

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

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2015 period. A range of potential improvements and degradations were determined for each of these metrics.

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

A. The Planned Outage Factor ("POF") and the Equivalent Unplanned Outage Factor ("EUOF") were subtracted from 100 percent to determine the target Equivalent

Availability Factor ("EAF"). The factors for each of the seven units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2015 period, the projected EUOF for Bayside Unit 1 is 5.2 percent, and the POF is 4.9 percent. Therefore, the target EAF for Bayside Unit 1 equals 89.9 percent or:

$$100\% - (5.2\% + 4.9\%) = 89.9\%$$

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

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

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

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

The factors included in the above equations are the same factors that determine the target equivalent availability. To determine the maximum incentive points, a 20 percent reduction in EUOF, plus a five percent reduction in the POF are necessary. Continuing with the Bayside Unit 1 example:

$$EAF_{MAX} = 1 - [0.80\ (5.2\%) + 0.95\ (4.9\%)] = 91.2\%$$

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

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

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

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

Again, continuing with the Bayside Unit 1 example,

$$EAF_{MIN} = 1 - [1.40\ (5.2\%) + 1.10\ (4.9\%)] = 87.3\%$$

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

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

A. The company's planned outages for January through December 2015 are shown on page 21 of Document No. 1. Two GPIF units have a major outage of 28 days or greater in 2015; therefore, two Critical Path Method diagrams are provided. Planned Outage Factors are calculated for each unit. For example, Bayside Unit 1 is scheduled for a planned outage from February 16, 2015 to February 24, 2015 and November 30, 2015 to December 8, 2015. There are 432 planned outage hours scheduled for the 2015 period, and a total of 8,760 hours during this 12-month period. Consequently, the POF for Bayside Unit 1 is 4.9 percent or:

$$\frac{432}{8{,}760} \times 100\% = 4.9\%$$

The factor for each unit is shown on pages 5 and 14 through 20 of Document No. 1. Big Bend Unit 1 has a POF of 23.0 percent. Big Bend Unit 2 has a POF of 6.6

percent. Big Bend Unit 3 has a POF of 6.6 percent. Big Bend Unit 4 has a POF of 6.6 percent. Polk Unit 1 has a POF of 13.7 percent. Bayside Unit 1 has a POF of 4.9 percent, and Bayside Unit 2 has a POF of 6.0 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 5.2 percent for Bayside Unit 1. The EUOF for Bayside Unit 1 is verified by the data shown on page 19, lines 3, 5, 10 and 11 of Document No. 1 and calculated using the following formula:

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

or

$$EUOF = \frac{(84 + 372)}{8,760} \times 100\% = 5.2\%$$

Relative to Bayside Unit 1, the EUOF of 5.2 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Big Bend Unit 1

The projected EUOF for this unit is 15.8 percent. The unit will have two planned outages in 2015, and the POF is 23.0 percent. Therefore, the target equivalent availability for this unit is 61.2 percent.

Big Bend Unit 2

The projected EUOF for this unit is 18.2 percent. The unit will have two planned outages in 2015, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 75.2 percent.

Big Bend Unit 3

The projected EUOF for this unit is 14.2 percent. The unit will have two planned outages in 2015, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 79.2 percent.

Big Bend Unit 4

The projected EUOF for this unit is 13.1 percent. The unit will have two planned outages in 2015, and the POF is 6.6 percent. Therefore, the target equivalent availability for this unit is 80.3 percent.

Polk Unit 1

The projected EUOF for this unit is 9.2 percent. The unit will have two planned outages in 2015, and the POF is 13.7 percent. Therefore, the target equivalent availability for this unit is 77.1 percent.

Bayside Unit 1

The projected EUOF for this unit is 5.2 percent. The unit will have two planned outages in 2015, and the POF is 4.9 percent. Therefore, the target equivalent availability for this unit is 89.9 percent.

Bayside Unit 2

The projected EUOF for this unit is 7.4 percent. The unit will have two planned outages in 2015, and the POF is 6.0 percent. Therefore, the target equivalent availability for this unit is 86.6 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 78.1 percent is shown on Page 5 of Document No. 1. This target is similar to last year’s January through December actual performance.

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 19 of Document No. 1. Except for the months of February, November, and December, the Equivalent Unplanned Outage Rate and the Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled during these months. During the months of February, November, and December, the Equivalent Unplanned Outage Rate exceeds the Equivalent Unplanned Outage Factor due to scheduled planned outages. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

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

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

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

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

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

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

Q. How were these targets determined?

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

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

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

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

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

Q. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2015 period.

A. The heat rate target for Big Bend Unit 1 is 10,563 Btu/Net kWh. The range about this value, to allow for potential improvement or degradation, is ±194 Btu/Net kWh. The heat rate target for Big Bend Unit 2 is 10,379 Btu/Net kWh with a range of ±230 Btu/Net kWh. The heat rate target for Big Bend Unit 3 is 10,495 Btu/Net kWh, with a range of ±169 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,416 Btu/Net kWh with a range of ±171 Btu/Net kWh. The heat rate target for Polk Unit 1 is 10,552 Btu/Net kWh with a range of ±532 Btu/Net kWh. The heat rate target for Bayside Unit 1 is 7,414 Btu/Net kWh with a range of ±92 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,447 Btu/Net kWh with a range of ±95 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within the range for each target. This is shown on page 4, and pages 7 through 13 of Document No. 1.

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

A. Yes.

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

A. The next step is to calculate the savings and weighting factor to be used for both average net operating heat rate and equivalent availability. This is shown on pages 7 through 13. The baseline production costing analysis was performed to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $596,119,836 is shown on page 6, column 2. Multiple production cost simulations were performed to calculate total system fuel cost with each unit individually operating at maximum improvement in equivalent availability and each station operating at maximum improvement in average net operating heat rate. The respective savings are shown on page 6, column 4 of Document No. 1.

After all of the individual savings are calculated, column 4 totals $15,405,074 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 6.02 percent as shown in the right-hand column on page 6. Pages 7 through 13 of Document No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, on Bayside Unit 1, page 12, if the unit operates at 7,322 average net operating heat rate, fuel savings would equal $928,043 and 10 average net operating heat rate points would be awarded.

The GPIF Reward/Penalty table on page 2 is a summary of the tables on pages 7 through 13. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, or $15,405,074. 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 2015 is $2,200,493,028. This produces the maximum allowed jurisdictional incentive of $8,993,880 shown on line 21.

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

A. Yes. Incentive dollars are not to exceed 50 percent of fuel savings. Page 2 of Document No. 1 demonstrates that this constraint is met, limiting total potential reward and penalty incentive dollars to $7,702,537.

Q. Please summarize your testimony.

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

$$\begin{aligned} GPIP: = (&0.0778\ EAP_{BB1} + 0.0204\ EAP_{BB2} \\ &+ 0.0149\ EAP_{BB3} + 0.0413\ EAP_{BB4} \\ &+ 0.0060\ EAP_{PK1} + 0.0339\ EAP_{BAY1} \end{aligned}$$

$$+ 0.1011\ EAP_{BAY2} + 0.0843\ HRP_{BB1}$$
$$+ 0.1129\ HRP_{BB2} + 0.0897\ HRP_{BB3}$$
$$+ 0.0886\ HRP_{BB4} + 0.1665\ HRP_{PK1}$$
$$+ 0.0602\ HRP_{BAY1} + 0.1024\ HRP_{BAY2})$$

Where:

GPIP = Generating Performance Incentive Points.

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

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

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2015 period?

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

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 140001-EI
FILED: 8/22/2014

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH II

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

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

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

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

Wholesale Products and Fuel Services in Tampa Electric's Wholesale Marketing group. My responsibilities are to evaluate short- and long-term purchase and sale opportunities within the wholesale power market, assist in wholesale origination and contract structure, and help evaluate the processes used to value potential wholesale power transactions. In this capacity, I interact with wholesale power market participants such as utilities, municipalities, electric cooperatives, power marketers, and other wholesale developers and independent power producers.

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

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

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

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

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

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

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

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

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

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

Q. Please describe Tampa Electric's 2014 wholesale energy purchases.

A. Tampa Electric assessed the wholesale power market and entered into short- and long-term purchases based on price and availability of supply. Approximately five percent of the expected energy needs for 2014 will be met using purchased power. This purchased power energy includes economy purchases, qualifying facilities, and existing firm purchased power agreements with Pasco Cogen, Calpine, and Southern Power Company. The testimony in previous years describes each existing firm purchased power agreement. However, in summary, all three purchases are call options with dual-fuel (*i.e.*, natural gas or oil) capability. The Pasco Cogen purchase is 121 MW of intermediate capacity and continues through 2018. Both Calpine and Southern Power Company are peaking purchases with capacities of 117 MW and 160 MW, respectively. The Southern Power Company purchase continues through 2015, while the Calpine purchase continues through 2016. All of the aforementioned purchases provide supply reliability, help reduce fuel price volatility, and were previously approved by the Commission as being cost-effective for Tampa Electric customers.

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

Q. Has Tampa Electric entered into any other wholesale energy purchases beyond 2014?

A. No, besides the previously mentioned purchases, the company has not entered into any other purchases beyond 2014.

Q. Does Tampa Electric anticipate entering into any other wholesale energy purchases for 2015 and beyond?

A. In 2015, the Tampa Electric expects purchased power to meet approximately five percent of its energy needs. This energy includes contributions from the three previously mentioned firm purchases. Beyond 2015, Tampa Electric expects the company's remaining two firm purchases (*i.e.*, Pasco Cogen and Calpine) to keep contributing positively to customers' level of electric service in the applicable years. Tampa Electric will continue to evaluate the short-term purchased power market as part of its purchasing strategy for 2015 and beyond.

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

A. Physical and financial hedges can provide measurable market price volatility protection. Tampa Electric purchases physical wholesale power products. The company has not engaged in financial hedging for wholesale transactions because the availability of financial instruments within the Florida market is limited. The Florida wholesale power market currently operates through bilateral contracts between various counterparties, and no Florida trading hub exists where standard financial transactions can occur with enough volume to create a liquid market. Due to this lack of liquidity and standard financial instruments, Tampa Electric has not purchased any financial wholesale power hedges. However, the company employs a diversified physical power supply strategy, which includes self-generation and short- and long-term capacity and energy purchases. This strategy provides the company the opportunity to take advantage of favorable spot market pricing while maintaining reliable service to its customers.

Q. Does Tampa Electric's risk management strategy for power transactions adequately mitigate price risk for purchased power for 2014?

A. Yes, Tampa Electric expects its physical wholesale purchases to continue to reduce its customers' purchased power price risk. For example, the 160 MW purchased from

Southern Power Company and 121 MW purchased from Pasco Cogen are reliable, cost-based call options for power. These purchases serve as both a physical hedge and reliable source of economic power. The availability of these purchases is high, and their price structures provide some protection from rising market prices, which are largely influenced by supply and the volatility of natural gas prices.

Mitigating price risk is a dynamic process, and Tampa Electric continually evaluates its options in light of changing circumstances and new opportunities. Tampa Electric also strives to maintain an optimum level and mix of short- and long-term capacity and energy purchases to augment the company’s own generation for the year 2014 and beyond.

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

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

Q. Please describe Tampa Electric’s wholesale energy sales for 2014 and 2015.

A. Tampa Electric entered into various non-separated wholesale sales in 2014, and the company anticipates making additional non-separated sales during the balance of 2014 and in 2015. In accordance with Order No. PSC-01-2371-FOF-EI, issued on December 7, 2001 in Docket No.

010283-EI, all gains from non-separated sales are returned to customers through the fuel clause, up to the three-year rolling average threshold. For all gains above the three-year rolling average threshold, customers receive 80 percent and the company retains the remaining 20 percent.

In 2014, Tampa Electric anticipates its gains from non-separated wholesale sales to be $3,069,762, which will exceed the three-year rolling average threshold of $681,121. Of the total gains from non-separated wholesale sales, customers will receive $2,592,034, which represents 100 percent of the $681,121 threshold value, plus $1,910,913 or 80 percent of the margin above the threshold. Tampa Electric will receive $477,728, which is the remaining 20 percent of the gains above the threshold.

The company did not project exceeding the threshold in 2014. However, the cold 2014 winter resulted in a higher than expected level of sales in January and February. In 2015, the company's projected gains from non-separated wholesale sales are $581,933, of which 100 percent is expected to be passed on to customers since they are less than the projected three-year rolling average threshold for that year of $1,403,580.

Q. Please summarize your testimony.

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

Q. Does this conclude your testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 140001-EI
FILED: 3/28/2014

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

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

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

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

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

A. Yes. I have previously testified before this Commission in Docket No. 120234-EI regarding the company's fuel procurement and delivery strategy for the Polk 2-5 Combined Cycle Conversion.

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 2013 results of Tampa Electric's risk management activities, as required by the terms of the stipulation entered into by the parties to Docket No. 011605-EI and approved by the Commission in Order No. PSC-02-1484-FOF-EI.

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

A. Yes. Exhibit No. ___ (JBC-1), entitled Tampa Electric's 2013 Hedging Activity True-up, was prepared under my direction and supervision. This report explains the company's risk management activities and results for the calendar year 2013.

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

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

Q. What were the results of Tampa Electric's risk management activities in 2013?

A. As outlined in Tampa Electric's 2013 Hedging Activity True-up, filed as an exhibit to this testimony, the company follows a non-speculative risk management strategy to reduce fuel price volatility while maintaining a reliable supply of fuel. In particular, Tampa Electric established a financial hedging program to limit customers' exposure to spikes in the price of natural gas. Over time, this program has been enhanced as Tampa Electric's gas needs have evolved and grown. All enhancements have been reviewed and approved by the company's Risk Authorization Committee.

The report indicates that Tampa Electric's 2013 hedging activities resulted in a net loss of approximately $3.3 million. Tampa Electric followed the plan objective of reducing price volatility while maintaining a reliable fuel supply. Natural gas prices declined in 2013 due to lower demand as a result of the mild winter of 2012/2013, ongoing economic softness, and an abundance of natural gas supply from non-conventional, shale gas production.

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

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

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

Q. Does Tampa Electric use a hedging information system?

A. Yes, Tampa Electric continues to use Sungard's Nucleus Risk Management System ("Nucleus"). Nucleus supports sound hedging practices with its contract management, separation of duties, credit tracking, transaction limits, deal confirmation, risk exposure analysis and business report generation functions. The Nucleus system records all financial natural gas hedging transactions, and the system calculates risk management reports. In 2013, Tampa Electric initiated a project to upgrade or replace Nucleus. The natural gas portion of this project is projected to be completed by the end of 2014.

Q. Did the company use financial hedges for commodities other than natural gas in 2013?

A. No. Tampa Electric did not use financial hedges for commodities other than natural gas in 2013.

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

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

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

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

A. Tampa Electric assures sufficient physical supply of coal and oil through supply diversification, inventory sufficiency, and delivery flexibility for coal. 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. This is of particular importance because of increasing competition for Illinois Basin coal supply. This increased competition comes from domestic utilities that have added sulfur dioxide scrubbers to their coal plants and from the international market. This competition for low cost supply puts greater emphasis on the need for a robust coal supply portfolio.

Additionally in 2009, Tampa Electric added rail delivery capability for coal to Big Bend Station. The addition of rail to the existing waterborne transportation facilities enhanced Tampa Electric’s access to coal supply and increased delivery reliability.

For oil, Tampa Electric fills its oil tanks prior to entering hurricane season to reduce exposure to supply or price issues that may arise during hurricane season. Competition for potentially limited oil supplies and oil transportation during a crisis emphasizes the need for maintaining sufficient inventory.

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

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

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

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 140001-EI
FILED: 7/25/2014

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. BRENT CALDWELL

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

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

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

A. I received a Bachelor Degree in Electrical Engineering from Georgia Institute of Technology in 1985 and a Master of Science degree in Electrical Engineering in 1988 from the University of South Florida. I have over 16 years of utility experience with an emphasis in state and federal regulatory matters, natural gas procurement and transportation, fuel logistics and cost reporting, and business systems analysis. In October

2010, I assumed responsibility for long term fuel supply planning and procurement for Tampa Electric's generation plants.

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

A. Yes, I am.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor and describe Exhibit No. _____ (JBC-2), entitled Tampa Electric Company's Fuel Procurement and Wholesale Power Purchases Risk Management Plan 2015.

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) sets forth all of the various details of Tampa Electric’s overall plan for mitigating risk in the company’s procurement of generation fuel and purchased power during 2015.

Q. Does this conclude your testimony?

A. Yes, it does.

TAMPA ELECTRIC COMPANY
DOCKET NO. 140001-EI
FILED: 08/22/2014

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, Bulk Fuel and Power.

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

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

Q. Have you previously testified before this Commission?

A. Yes. I have submitted written testimony in the annual fuel docket since 2011, and I testified before the Commission in Docket No. 120234-EI regarding the company's fuel procurement for the Polk 2-5 Combined Cycle Conversion project.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss Tampa Electric's fuel mix, fuel price forecasts, potential impacts to fuel prices, and the company's fuel procurement strategies. I will address steps Tampa Electric takes to manage fuel supply reliability and price volatility and describe projected hedging activities.

2015 Fuel Mix and Procurement Strategies

Q. What fuels will Tampa Electric's generating stations use in 2015?

A. In 2015, coal-fired generation is expected to be approximately 63 percent, and natural-gas fired generation is expected to be 37 percent, of total generation. Generation from oil is expected to be less than one percent of the total generation.

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

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

Coal Supply Strategy

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

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

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

Q. Please summarize Tampa Electric's solid fuel, coal and petroleum coke, supply for 2014.

A. Tampa Electric supplies Big Bend Station's coal needs through a combination of two coal supply agreements that continue through 2014 and a collection of shorter term contracts and spot purchases. These shorter term purchases allow the company to adjust supply to reflect changing coal quality and quantity needs, operational changes and pricing opportunities.

Q. Has Tampa Electric entered into coal supply transactions for 2015 delivery?

A. Yes, Tampa Electric has contracted for more than three-fourths of its 2015 expected coal needs through agreements with coal suppliers to mitigate price volatility and ensure reliability of supply. Tampa Electric anticipates the remaining solid fuel purchases for Big Bend Station and Polk Unit 1 will be procured through spot market purchases during 2014 and 2015.

Coal Transportation

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

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

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, 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 2014 and 2015?

A. Yes. Tampa Electric expects to receive over two million tons of coal through the Big Bend rail facility during 2015, for use at Big Bend Station.

As part of the CSX transportation agreement, Tampa Electric receives a per ton discount, treated as a reimbursement, for each ton of coal delivered, all of which is flowed through to customers through the fuel and purchased power cost recovery clause. Although the current agreement with CSX was scheduled to expire at the end of 2014, the company has reached an agreement to extend the contract. In addition to the term extension, the contract amendment extends the available per ton discount for rail transportation, treated as a reimbursement, and replaces the minimum annual throughput with a fixed capacity reservation. The per-ton discount, or reimbursement, will continue to be flowed through to customers through the fuel and purchased power cost recovery clause. The amended contract rate structure makes the effective rate lower than the previous agreement at the expected level of rail deliveries.

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

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

Tampa Electric's existing waterborne transportation agreements for river, terminal and Gulf expire at the end of 2014. Tampa Electric issued an RFP for waterborne transportation services in early 2014. The company is negotiating agreements with the terminal services and ocean transportation providers, and Tampa Electric expects to finish negotiating new agreements for these two transportation components by the end of the third quarter of 2014. Tampa Electric is in the process of selecting river transportation provider(s) and expects to make a final selection by the end of August 2014, with final agreement(s) in place by the end of the fourth quarter of 2014. Tampa Electric anticipates that the new waterborne transportation agreements will provide greater flexibility and reduce overall waterborne transportation costs. These estimated lower transportation costs are incorporated in the company’s 2015 delivered fuel cost projections.

Q. Please describe any other significant factors that Tampa Electric considered in developing its 2015 solid fuel supply portfolio.

A. Tampa Electric placed an emphasis on flexibility in its solid fuel supply portfolio. The company recognizes that several factors may impact the annual consumption of solid fuel. There are several environmental regulations being enacted or proposed to be enacted in the next few years. These regulations may affect the types or quantities of coal that can be consumed at the stations or most likely, both. Also, Tampa Electric and Florida’s generation assets continue to evolve. Tampa Electric is in the process of converting the natural gas combustion turbines at Polk Power Station into a very efficient natural gas combined cycle unit. Several new natural gas combined cycle units recently have been built within the state. Depending on the relative price of delivered solid fuel, delivered natural gas and the dynamics of the wholesale power market, the actual quantity of solid fuel burned may vary each year. Tampa Electric strives to balance the need to have reliable solid fuel commodity and transportation while mitigating the potential for significant shortfall penalties if the commodity or transportation is not needed.

Natural Gas Supply Strategy

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

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

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

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

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

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

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

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

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

Q. Has Tampa Electric entered any natural gas supply transactions for 2015 delivery?

A. Yes. Tampa Electric is currently in the process of securing approximately two-thirds of the company's expected natural gas requirements for 2015. The balance of Tampa Electric's natural gas supply will be acquired through seasonal, monthly and daily purchases to meet its varying operational needs.

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

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

Projected 2015 Fuel Prices

Q. How does Tampa Electric project fuel prices?

A. Tampa Electric reviews fuel price forecasts from sources widely used in the industry, including the New York Mercantile Exchange ("NYMEX"), Wood Mackenzie, the Energy Information Administration, and other energy market information sources. Futures prices for energy commodities as traded on the NYMEX form the basis of the natural gas and No. 2 oil market commodity price forecasts. The commodity price projections are then adjusted to incorporate expected transportation costs and location differences.

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

Q. How do the 2015 projected fuel prices compare to the fuel prices projected for 2014?

A. Fuel prices for coal and natural gas for 2015 are projected to be similar to the prices projected for 2014. The colder than expected 2013 through 2014 winter increased demand for natural gas and coal in the short term. However, natural gas production from shale reserves has easily met this increased natural gas demand and is keeping prices relatively stable. Natural gas prices are projected to be slightly higher in 2015 than the actual/estimated natural gas prices expected for 2014, primarily driven by anticipated improvement to the economy and a market adjustment to shale gas production. Similarly, the higher coal demand is offset by coal-fired unit closures that will reduce demand, and coal prices are expected to remain stable.

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

A. Yes. While projected 2015 prices for coal and natural gas are expected to be similar to 2014 prices, Tampa Electric recognizes that there is uncertainty in future prices. Therefore, Tampa Electric prepared a scenario in which the forecasted price for natural gas was increased by 35 percent. Similarly, Tampa Electric prepared a scenario in which the forecasted price for natural gas was reduced by 20 percent. Due to Tampa Electric's generating mix combined with its Commission-approved natural gas hedging strategy, the impact of the fuel price changes under either scenario is mitigated.

Risk Management Activities

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

A. Tampa Electric complies with its risk management plan as approved by the company's Risk Authorizing Committee. Tampa Electric's plan is described in detail in the Fuel Procurement and Wholesale Power Purchases Risk Management Plan ("Risk Management Plan"), submitted to the Commission on July 25, 2014 in this docket.

Q. Has Tampa Electric used financial hedging in an effort to mitigate the price volatility of its 2014 and 2015 natural gas requirements?

A. Yes. Tampa Electric hedged a significant portion of its 2014 natural gas supply needs and a portion of its expected 2015 natural gas supply needs in accordance with its plan. Tampa Electric will continue to take advantage of available natural gas hedging opportunities in an effort to benefit its customers, while complying with its approved Risk Management Plan. The current market position for natural gas hedges was provided in the company's Natural Gas Hedging Activities report submitted to the Commission in this docket on August 13, 2014.

Q. Are the company's strategies adequate for mitigating price risk for Tampa Electric's 2014 and 2015 natural gas purchases?

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

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

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

Q. Were Tampa Electric’s efforts through July 31, 2014 to mitigate price volatility through its non-speculative hedging program prudent?

A. Yes. Tampa Electric has executed hedges according to the risk management plan filed with this Commission, which was approved by the company’s Risk Authorizing Committee. On March 28, 2014, the company filed its 2013 Natural Gas Hedging Activities report. Additionally, utilities must submit a Natural Gas Hedging Activity Report showing the results of hedging activities from January through July of the current year. The Hedging Activity Report facilitates prudence reviews through July 31 of the current year and allows for the Commission’s prudence determination at the annual fuel hearing. Tampa Electric filed its Natural Gas Hedging Activities report, showing the results of its prudent hedging activities from January through July 2014, in this docket on August 13, 2014.

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

A. No. The primary objective of the company's hedging program is to reduce fuel price volatility as approved by the Commission. Tampa Electric's hedging program requires consistent hedging based on expected needs. The company does not engage in speculative hedging strategies aimed at out-guessing the market. This discipline ensures hedges will be in place should prices spike and also means hedges are in place when prices decline and removes some of the volatility and uncertainty in natural gas prices from the fuel costs to generate electricity for customers, but does not guarantee fuel savings.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF SIMON O. OJADA

DOCKET NO. 140001-EI

September 12, 2014

Q. Please state your name and business address.

A. My name is Simon O. Ojada. My business address is 4950 West Kennedy Blvd., Suite 310, Tampa, Florida 33609.

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

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

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

A. I have been employed by the Florida Public Service Commission since 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 Recovery Clause, Docket No. 130001-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Duke Energy Florida, Inc. (DEF or Utility) which addresses the filing in Docket No. 140001-EI Fuel and purchased power cost recovery clause for costs associated with its hedging activities. We issued an audit report in this docket for the hedging activities on September 8, 2014. This audit report is filed with my testimony and is identified as Exhibit SOO-1.

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

A. Yes, it was prepared under my direction.

Q. Please describe the work performed in this audit.

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

<u>Accounting Treatment</u>

I reviewed DEF's supporting detail of the hedging settlements for the twelve months ended July 31, 2014. I verified the monthly balances of hedging transactions from DEF's Hedging Results Report for the period August 1, 2013, to December 30, 2013, and its Hedging Information Report for the period January 1, 2014 to July 31, 2014 to its Hedging Summary by Commodity Reports for 2013 and 2014 to the general ledger. No exceptions were noted.

<u>Gains and Losses</u>

I selected 21 natural gas and two No. 2 oil hedging transactions from August 2013 through July 2014 as a sample. I reconciled the selected samples from the Hedging Results and Hedging information Reports to the third-party confirmation notices and contracts. I reconciled the gains and losses to the Utility's journal entries. I compared the price on the confirmation notice to the price published by the NYMEX Henry Hub gas futures contract rates. No exceptions were noted.

<u>Hedged Volume and Limits</u>

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

Separation of Duties

I reviewed DEF's written procedures for separation of duties related to hedging activities. I reviewed the DEF's Audit Services Department evaluations and reports for the twelve months ending December 31, 2013. No exceptions were noted.

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

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

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF ILIANA H. PIEDRA

DOCKET NO. 140001-EI

SEPTEMBER 12, 2014

Q. Please state your name and business address.

A. My name is Iliana H. Piedra. My business address is 3625 N.W. 82nd Ave., Suite 400, Miami, Florida, 33166.

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

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

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

A. I have been employed by the Florida Public Service Commission since January 1985.

Q. Briefly review your educational and professional background.

A. I received a Bachelor of Business Administration degree with a major in accounting from Florida International University in 1983. I am also a Certified Public Accountant licensed in the State of Florida.

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 presented testimony before this Commission or any other regulatory agency?

A. Yes. I filed testimony in the City Gas Company of Florida rate case, Docket No. 940276-GU, the General Development Utilities, Inc. rate cases for the Silver Springs Shores Division in Marion County and the Port Labelle Division in Glades and Hendry Counties in

Dockets Nos. 920733-WS and 920734-WS, respectively, the Florida Power & Light Company storm cost recovery case in Docket No. 041291-EI, the Embarq storm cost recovery case in Docket No. 060644-TL, the K W Resort Utilities Corp. rate case in Docket No. 070293-SU, the Florida Power & Light Company fuel recovery in Docket 120001-EI, Docket No. 130009-EI related to Florida Power & Light Company's Proposed Turkey Point Units 6 and 7, and the Florida Power & Light Company hedging activities in Docket 130001-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Florida Power & Light Company (FPL or Utility) which addresses the Utility's filing in Docket No. 140001-EI Fuel and purchased power cost recovery clause for costs associated with its hedging activities. We issued an audit report in this docket for the hedging activities on September 8, 2014. This audit report is filed with my testimony and is identified as Exhibit IHP-1.

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

A. Yes, it was prepared under my direction.

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

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

<u>Accounting Treatment</u>

We obtained FPL's supporting detail of the hedging settlements for the twelve months ended July 31, 2014. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements were in compliance with the Risk Management Plan and verified that the accounting treatment for hedging transactions and transactions costs are consistent with Commission orders relating to hedging activities. No exceptions were noted.

Gains and Losses

We traced the monthly balances of hedging transactions from FPL's March 28 and August 13, 2014 filings in this docket for the period August 1, 2013 to July 31, 2014 to FPL's Derivative Settlement Report. We selected various hedging transactions from various counterparties from August 2013 and April 2014 for natural gas as a sample and traced them from the Derivative Settlement Report to the invoices, purchase statements, confirmation notices and deal tickets. FPL does not have any tolling agreements where natural gas is provided to generators under purchase power agreements. We recalculated the gains and losses. We compared these recalculated gains and losses with FPL's journal entries for realized gains and losses. We compared a sample of the purchase prices to the futures rates published by the NYMEX Henry Hub gas futures contract rates. We traced a sample of settlement prices to the futures rates published by the NYMEX Henry Hub gas futures contract rates. No exceptions were noted.

Hedged Volume and Limits

We reviewed the quantity limits and authorizations. We also obtained FPL's analysis of the monthly percent of fuel hedged in relation to fuel burned for the twelve months ended July 31, 2014, and compared them with the Utility's Risk Management Plan. The hedged targets for natural gas were traced to the Planned Position Strategy Schedule. The fuel burn forecast was traced to the Fuel Burn Summary. No exceptions were noted.

Separation of Duties

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

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

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

Q. Does that conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF DEBRA M. DOBIAC

DOCKET NO. 140001-EI

SEPTEMBER 12, 2014

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 whom are you presently employed and in what capacity?

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

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

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

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 6 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. Please describe your current responsibilities.

A. Currently, I am a Public Utilities Analyst II 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. 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. 080121-WS, the Water Management Services, Inc. Rate Case, Docket No. 100104-WU, the Gulf Power Company Rate Case, Docket No. 110138-EI, the Water Management Services, Inc. Rate Case, Docket No. 110200-WU, the Gulf Power Company Fuel and Purchased Power Recovery Clause, Docket No. 130001-EI, and the Gulf Power Company Rate Case, Docket No 130140-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Gulf Power Company (Gulf or Utility) which addresses the Utility's filing in Docket No. 140001-EI Fuel and purchased power cost recovery clause for costs associated with its hedging activities. We issued an audit report in this docket for the hedging activities on September 4, 2014. This audit 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 under my direction.

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, 2014. The support documentation was traced to the general ledger transaction detail. We verified that the hedging settlements are in compliance with the Risk Management Plan and verified that the accounting treatment for hedging transactions and transactions costs is consistent with Commission orders relating to hedging activities. No exceptions were noted.

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, 2013 to July 31, 2014. We reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. We recalculated the gains and losses, traced the price to the settlement statement details, and compared the price to the gas futures rates published by the New York Mercantile Exchange (NYMEX) Henry Hub Gas futures contract rates. We compared these recalculated gains and losses with Gulf's journal entries for realized gains and losses. No exceptions were noted.

Hedged Volume and Limits

We reviewed the quantity limits and authorizations. We also obtained Gulf's analysis of the monthly percent of natural gas hedged in relation to natural gas burned for the twelve months ended July 31, 2014, and compared them with the Utility's Risk Management Plan. No exceptions were noted.

Separation of Duties

We reviewed the Utility's procedures for separating duties related to hedging activities. There were no internal or external audits related to hedging activities. No exceptions were noted.

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

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

Q. Does that conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF INTESAR TERKAWI

DOCKET NO. 140001-EI

September 12, 2014

Q. Please state your name and business address.

A. My name is Intesar Terkawi. My business address is 4950 West Kennedy Blvd., Suite 310, Tampa, Florida 33609.

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

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

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

A. I have been employed by the Florida Public Service Commission since October 2001.

Q. Briefly review your educational and professional background.

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

Q. Please describe your current responsibilities.

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

Q. Have you previously presented testimony before this Commission?

A. No.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to sponsor the staff audit report of Tampa Electric Company (TECO or Utility) which addresses the Utility's filing in Docket No. 140001-EI Fuel and Purchased Power Cost Recovery Clause for costs associated with its hedging activities. We issued an audit report in this docket for the hedging activities on September 8, 2014. This audit report is filed with my testimony and is identified as Exhibit IT-1.

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

A. Yes, it was prepared under my direction.

Q. Please describe the work performed in this audit.

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

Accounting Treatment

I reviewed TECO's supporting detail of the hedging settlements for the twelve months ended July 31, 2014. I traced the transactions to the general ledger and trade confirmation documents. I verified that the hedging settlements were in compliance with the Risk Management Plan and verified that the accounting treatment for hedging transactions and transactions costs are consistent with Commission orders relating to hedging activities. No exceptions were noted.

Gains and Losses

I traced the monthly balances of hedging transactions from TECO's Hedging Information Report to its Mark to Market Position Report for the period August 1, 2013, to July 31, 2014. I selected all gas hedging transactions for October and November 2013 and traced them from the Mark to Market Position Report to the third-party confirmation notices and contracts. I traced a sample of the purchase prices to the Gas Daily – NYMEX Henry Hub gas futures contract rates. I traced the related settlements prices to the Gas Daily – NYMEX Henry Hub gas futures contract rate. I recalculated the gains and losses and traced them to the Utility's journal entries for realized gains and losses. I reviewed existing tolling agreements whereby the Utility's natural gas is provided to generators under purchased power agreements. No exceptions were noted.

Hedged Volume and Limits

I reviewed the quantity limits and authorizations. I also obtained TECO's analysis of the monthly percent of fuel hedged in relation to fuel burned for the twelve months ended July 31, 2014, and compared them with the Utility's Risk Management Plan. There were variances for 4 of the 12 months between the percentages of actual and projected natural gas burned that were hedged. All variances were a result of inaccurate forecasting. No further work was done.

Separation of Duties

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

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

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

Q. Does this conclude your testimony?

A. Yes.

CHAIRMAN GRAHAM: And what about exhibits?

MS. BARRERA: Staff has compiled a stipulated Comprehensive Exhibit List, which includes the prefiled exhibits attached to the witnesses' testimony in this case. The list has been provided to the parties, the Commissioners, and the court reporter. This list is marked as the first hearing exhibit, and the other exhibits should be marked as set forth in the list. All exhibits have been stipulated. Staff recommends that the exhibits listed in the Comprehensive Exhibit List as Exhibits 2 to 18 and 24A to 68 be entered into the record at this time. Exhibits 19 to 24 will be proffered at the end of Mr. Foster's testimony.

CHAIRMAN GRAHAM: Did you say 24A to 68?

MS. BARRERA: Yes, sir.

CHAIRMAN GRAHAM: Okay. So we will enter Exhibits 1 through 18 and 24A through 68 into the record.

MS. BARRERA: Yes. Thank you.

CHAIRMAN GRAHAM: Are there any objections? Seeing none, we will enter that into the record.

(Exhibits 1 through 68 marked for identification.

(Exhibits 1 through 18 and 24A through 68 admitted into the record.)

All right. Contested issues. I guess it's time for opening statements.

MR. BERNIER: Good morning, Commissioners. This docket has been fully stipulated with the exception of two issues: First, whether we have made the necessary adjustments and refunds to our 2015 fuel factors that are required under the revised and restated Stipulation and Settlement Agreement approved by this Commission; and, second, whether we have properly accounted for and excluded the replacement power costs associated with the Bartow plant outage. The answer to both issues is, yes, we have made the necessary adjustments.

Our prefiled testimony and exhibits fully demonstrate that the necessary adjustments and refunds have been included in the 2014 fuel recovery and 2015 fuel factors. Mr. Thomas Foster is here today to respond to questions in further support of those adjustments. Thank you.

CHAIRMAN GRAHAM: Any other opening statements?

Mr. Rehwinkel.

MR. REHWINKEL: Thank you, Commissioners, for the opportunity to be heard today and to make a very brief opening statement.

The Public Counsel has some questions that need to be asked of Duke in open hearing for two reasons: First, inasmuch as over $1 billion in refunds and approximately $120 million in early recovery of the CR3 stranded asset resulting from the loss of the Crystal River nuclear unit agreed to by the parties and approved by the Commission have been or will be returned to or imposed upon customers through the fuel adjustment clause, it is important that this process be tracked and verified carefully and with full transparency to the public. Duke has worked with the Commission and the parties to make sure that this process is transparent, and we commend them for that.

Second, Duke has incurred replacement power costs associated with two unplanned outages in 2014. It is important for the customers to understand what Duke intends to do to account for these costs and that that understanding come on the record.

The Public Counsel is ever mindful that Duke has the burden of proof to demonstrate the reasonableness and the prudence of the costs it seeks to recover and its use of the fuel clause mechanism to make rate adjustments. The Public Counsel has insisted that this process take place on the record because of the uniqueness of this company's situation compared to the circumstances of the other IOUs and the need for Duke to meet its burden at hearing. Thank you.

CHAIRMAN GRAHAM: Thank you, Mr. Rehwinkel. Any other opening statements?

Okay. Duke, I think it's time for you to call your witness.

MR. BERNIER: Thank you, Mr. Chairman. Duke Energy calls Mr. Thomas Foster.

Whereupon,

THOMAS FOSTER

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

BY MR. BERNIER:

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

A Yes. My name is Thomas Foster. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

Q Who do you work for and what is your position?

A I work for Duke Energy Florida. I'm the Director of Rates and Regulatory Planning.

Q Did you file prefiled direct testimony and exhibits on March 3rd, July 25th, and August 22nd in this proceeding?

A Yes, I did.

Q Do you have a copy of your prefiled testimony and exhibits in this proceeding with you today?

A Yes, I do.

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

A No, I do not.

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

A Yes.

MR. BERNIER: Mr. Chairman, we request that the prefiled testimony be entered into the record as if it was read today.

CHAIRMAN GRAHAM: We will enter Mr. Foster's prefiled direct testimony into the record as though read.

MR. BERNIER: Thank you.

DUKE ENERGY FLORIDA

DOCKET NO. 140001-EI

**Fuel and Capacity Cost Recovery
Actual True-Up for the Period
January through December, 2013**

**DIRECT TESTIMONY OF
Thomas G. Foster**

March 3, 2014

Q. Please state your name and business address.

A. My name is Thomas G. Foster. My business address is 299 First Avenue North, St. Petersburg, Florida 33701.

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

A. I am employed by Duke Energy Business Services LLC as Director, Rates & Regulatory Strategy.

Q. What are your responsibilities in that position?

A. I am responsible for regulatory planning and cost recovery for Duke Energy Florida, Inc. ("DEF" or the "Company"). These responsibilities include: regulatory financial reports; and analysis of state, federal, and local regulations and their impact on DEF.

Q. Please describe your educational background and professional experience.

A. I joined Duke Energy Florida on October 31, 2005 as a Senior Financial analyst in the Regulatory group. In that capacity I supported the preparation of testimony and exhibits associated with various Dockets. In late 2008, I was promoted to Supervisor Regulatory Planning. In 2012, I was promoted to my current position. Prior to working at Duke, I was the Supervisor in the Fixed Asset group at Eckerd Drug. In this role I was responsible for ensuring proper accounting for all fixed assets as well as various other accounting responsibilities. I have 6 years of experience related to the operation and maintenance of power plants obtained while serving in the United States Navy as a Nuclear operator. I received a Bachelors of Science degree in Nuclear Engineering Technology from Thomas Edison State College. I received a Masters of Business Administration with a focus on finance from the University of South Florida and I am a Certified Public Accountant in the State of Florida.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe DEF's Fuel Adjustment Clause final true-up amount for the period of January through December 2013, and DEF's Capacity Cost Recovery Clause final true-up amount for the same period.

Q. Have you prepared exhibits to your testimony?

A. Yes, I have prepared and attached to my true-up testimony as Exhibit No. __(TGF-1T), a Fuel Adjustment Clause true-up calculation and related schedules; Exhibit No. __(TGF-2T), a Capacity Cost Recovery Clause true-up calculation and related schedules; Exhibit No. __(TGF-3T), Schedules A1 through A3, A6, and A12 for December 2013, year-to-date; and Exhibit No. __(TGF-4T), a schedule outlining the 2013 capital structure and cost rates applied to capital projects. Exhibit No. __(TGF-4T) is included for informational purposes only, as DEF's 2013 Actual True-Up Filing does not include a capital return component. Schedules A1 through A9, and A12 for the year ended December 31, 2013, were previously filed with the Commission on January 21, 2014.

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

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

Q. Would you please summarize your testimony?

A. Per Order No. PSC-13-0665-FOF-EI, the projected 2013 fuel adjustment true-up amount was an under-recovery of $33.2 million. The actual under-recovery for 2013 was $6.0 million resulting in a final fuel adjustment true-up over-recovery amount of $27.2 million. Exhibit No. __(TGF-1T).

The projected 2013 capacity cost recovery true-up amount was an under-recovery of $24.4 million. The actual amount for 2013 was an under-recovery of $30.8 million resulting in a final capacity true-up under-recovery amount of $6.5 million. Exhibit No. __(TGF-2T).

FUEL COST RECOVERY

Q. What is DEF's jurisdictional ending balance as of December 31, 2013 for fuel cost recovery?

A. The actual ending balance as of December 31, 2013 for true-up purposes is an under-recovery of $5,961,090.

Q. How does this amount compare to DEF's estimated 2013 ending balance included in the Company's estimated/actual true-up filing?

A. The actual true-up amount attributable to the January - December 2013 period is an under-recovery of $5,961,090, which is $27,234,093 lower than the re-projected year end under-recovery balance of $33,195,183.

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

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

Q. What factors contributed to the period-ending jurisdictional under-recovery of $5,961,090 shown on your Exhibit No. __(TGF-1T)?

A. The factors contributing to the under-recovery are summarized on Exhibit No. __(TGF-1T), sheet 1 of 7. Net jurisdictional fuel revenues were favorable to the forecast by $82.6 million, while jurisdictional fuel and purchased power expense increased $16.3 million, resulting in a difference in jurisdictional fuel revenue and expense of $66.3 million. The $16.3 million increase in jurisdictional fuel and purchase power expense is primarily attributable to an unfavorable system variance from projected fuel and net purchased power of $22.1 million as more fully described below. The $6.0 million under-recovery also includes the deferral of $72.2 million of 2012 under-recovery approved in Order No. PSC-13-0665-FOF-EI. The net result of the difference in jurisdictional fuel revenues and expenses of $66.3 million, plus the 2012 deferral of $72.2 million and the 2013 interest provision calculated on the deferred balance throughout the year is an under-recovery of $6.0 million as of December 31, 2013.

Q. Please explain the components contributing to the $27.2 million variance between the actual under-recovery of $6.0 million and the approved, estimated/actual under-recovery of $33.2 million.

A. The major factors contributing to the $27.2 million variance, excluding the $129 million RRSSA refund which is discussed in the testimony below, are a $5.7 million decrease in sales and a $32.0 million decrease in system fuel and net power costs.

The $32.0 decrease in system fuel and net power results from a reduction in purchased power expense partially offset by an increase in generation costs.

Q. Please explain the components shown on Exhibit No. __(TGF-1T), sheet 6 of 7 which helps to explain the $22.1 million unfavorable system variance from the projected cost of fuel and net purchased power transactions.

A. Exhibit No. __(TGF-1T), sheet 6 of 7 is an analysis of the system dollar variance for each energy source in terms of three interrelated components; (1) changes in the <u>amount</u> (MWH's) of energy required; (2) changes in the <u>heat rate</u> of generated energy (BTU's per KWH); and (3) changes in the <u>unit price</u> of either fuel consumed for generation ($ per million BTU) or energy purchases and sales (cents per KWH). The $22.1 million unfavorable system variance is mainly attributable to higher than projected fuel pricing, partially offset by lower than expected purchased power transactions and the higher than projected final NEIL reimbursement. This is further broken out on Schedule A2, Page 1 of 2.

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

A. Yes. Noteworthy adjustments are shown on Exhibit No. __(TGF-3T) in the footnote to line 6b on page 1 of 2, Schedule A2. Included in the footnote to line 6b on page 1 of 2, Schedule A2, are the final NEIL reimbursement adjustment of $492.3 million (system grossed up from retail) and a reduction of $11.1 million for the incremental cost of replacement power provided the joint owners of CR-3 per DEF's Joint Ownership Agreements.

Q. Please explain the adjustment of $11.1 million for the incremental cost of replacement power provided the joint owners of the Crystal River nuclear unit (CR-3).

A. Per agreements with the joint owners of CR-3, if DEF does not meet a specific capacity factor for this unit per a designated two-year interval, DEF must replace enough power to meet the capacity factor or reimburse the joint owners for their cost of replacing the power. DEF decided to replace CR-3 joint owner power throughout 2013. For each hour replacement power was provided the joint owners of CR-3, DEF calculated the fuel costs on the incremental generating units that ran during those hours and the replacement MW. The incremental cost of the replacement power was then adjusted from generated fuel expense in order to remove these costs from fuel expense recovered from our retail ratepayers.

Q. Did the Company make an adjustment for changes in coal inventory based on an Aerial Survey?

A. Yes, DEF included a favorable adjustment of $7.8 million to coal inventory, which is attributable to the semi-annual aerial surveys conducted on October 16, 2012 and May 24, 2013 in accordance with Order No. PSC-97-0359-FOF-EI, found in Docket No. 970001-EI. This adjustment represents 1.78% of the total coal consumed at the Crystal River facility in 2013.

Q. Were there any impacts to the 2013 True-up filing associated with the 2013 Revised and Restated Stipulation and Settlement Agreement (RRSSA)?

A. Yes. Paragraphs 6.a, 7.c and 7.d all impact the 2013 true-up. Paragraph 6.a. requires DEF to refund to retail ratepayers 50% of $258 million, or $129 million, in 2013 through the Fuel Clause. Paragraph 7.c addresses how DEF will credit the final NEIL reimbursement through the Fuel Adjustment Clause. Paragraph 7.d relates to recovery of previously deferred amounts associated with estimated NEIL recoveries. These impacts are addressed further in the testimony below.

Q. Have you included these impacts in your calculation of the true-up balance?

A. Yes.

Q. Please describe where the impact of paragraph 6.a is included in your schedules and how this is included in the final true-up amount?

A. Exhibit No.___ (TGF-1T) (Sheets 2 and 3 of 7) show the refund of $129 million on line C.1a allocated evenly over the 12 month period. This amount is included in the 2013 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

Q. Please describe where the impact of paragraph 7.c is included in your schedules and how this is included in the final true-up amount?

A. The impact of paragraph 7.c can be seen in Exhibit No.___ (TGF-1T) (Sheets 2 and 3 of 7) line A.5. This line shows Adjustments to Fuel Cost for the period of $515 million. This is a system amount and includes other adjustments as well as the final NEIL payment. A breakout of this amount can be seen on Sheet 7 of Exhibit No.___ (TGF-1T). Lines 1-3 show the breakout at the system level while lines 5-7 show these numbers on a retail basis. Line 5 shows a total retail adjustment of $490 million was included in true-up. It can be seen flowing through Exhibit No.___ (TGF-1T) (Sheets 2 and 3) on line A.5 which is included in the calculation of the Total True-up Balance, Line C.13.

Q. Please describe where the impact of paragraph 7.d is included in your schedules and how this is included in the final true-up amount?

A. The impact of collecting the $326 million is inherently included in line C.1 of Exhibit No.___ (TGF-1T) (Sheet 2 and 3). It is inherently there because when 2013 rates were set in 2012, this amount was removed from rates based on assumed recovery from NEIL in this amount. This means, that rates were set to collect $326 million less than DEF's actual expected 2013 costs. The $163 million referenced in paragraph 7.d of the RRSSA is simply the net difference between the $490 million and the $326 million described above. This amount can be seen on line 19a of Exhibit No.___ (TGF-1T) Sheet 6 of 7.

Q. Did DEF exceed the economy sales threshold in 2013?

A. No. DEF did not exceed the gain on economy sales threshold of $0.6 million in 2013. As reported on Schedule A1, Line 15a, the gain for the year-to-date period through December 2013 was $0.4 million. This entire amount was returned to customers through a reduction of total fuel and net power expense recovered through the fuel clause.

Q. Has the three-year rolling average gain on economy sales included in the Company's filing for the November, 2013 hearings been updated to incorporate actual data for all of year 2013?

A. Yes. DEF has calculated its three-year rolling average gain on economy sales, based entirely on actual data for calendar years 2011 through 2013, as follows:

Year	Actual Gain
2011	352,650
2012	298,813
2013	427,107
Three-Year Average	$359,523

CAPACITY COST RECOVERY

Q. What is the Company's jurisdictional ending balance as of December 31, 2013 for capacity cost recovery?

A. The actual ending balance as of December 31, 2013 for true-up purposes is an under-recovery of $30,849,951.

Q. How does this amount compare to the estimated 2013 ending balance included in the Company's estimated/actual true-up filing?

A. When the estimated 2013 under-recovery of $24,360,251 is compared to the $30,849,951 actual under-recovery, the final capacity true-up for the twelve month period ended December 2013 is an under-recovery of $6,489,700.

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

A. Yes. The calculation of the final net true-up amount follows the procedures established by the Commission in Order No. PSC-96-1172-FOF-EI. The true-up amount was determined in the manner set forth on the Commission's standard forms previously submitted by the Company on a monthly basis.

Q. What factors contributed to the actual period-end capacity under-recovery of $30.8 million?

A. Exhibit No. __(TGF-2T, sheet 1 of 3) compares actual results to the original projection for the period. The $30.8 million under-recovery is due primarily to the higher than projected capacity expenses, lower than projected capacity revenues and a higher than projected actual under-recovery in 2012.

OTHER MATTERS

Q. On November 8, 2013, a fire occurred at the Crystal River facility resulting in Crystal River Unit 1 (CR1) being taken offline. Did DEF incur any costs to purchase replacement power due to the CR1 outage?

A: No. DEF had planned for Crystal River Unit 1 (CR1) to be placed in reserve shutdown during the time of this outage. Therefore CR1 was neither expected nor needed to run during the outage timeframe; thus DEF did not incur any replacement power costs associated with this outage.

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

A: Yes. A confidential version of Schedule A12 is included in Exhibit No. __(TGF-3T).

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

A. Yes.

DUKE ENERGY FLORIDA

DOCKET NO. 140001-EI

Fuel and Capacity Cost Recovery
Estimated/Actual True-Up Amounts
January through December 2014

DIRECT TESTIMONY OF
Thomas G. Foster

July 25, 2014

Q. Please state your name and business address.

A. My name is Thomas G. Foster. My business address is 299 1st Avenue North, St. Petersburg, Florida 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 140001-EI?

A. Yes, I provided direct testimony on March 3, 2014.

Q: Has your job description, education background and professional experience changed since that time?

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission approval, Duke Energy Florida's (DEF or the Company) estimated/actual fuel and capacity cost recovery true-up amounts for the period of January through December 2014.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared Exhibit No.__ (TGF-2), which is attached to my prepared testimony, consisting of two parts. Part 1 consists of Schedules E1-B through E9, which include the calculation of the 2014 estimated/actual fuel and purchased power true-up balance and a schedule to support the capital structure components and cost rates relied upon to calculate the return requirements on all capital projects recovered through the fuel clause as required per Order No. PSC-14-0001-PCO-EI. Part 2 consists of Schedules E12-A through E12-C, which include the calculation of the 2014 estimated/actual capacity true-up balance. The calculations in my exhibit are based on actual data from January through June 2014 and estimated data from July through December 2014.

FUEL COST RECOVERY

Q. What is the amount of DEF's 2014 estimated fuel true-up balance and how was it developed?

A. DEF's estimated fuel true-up balance is an under-recovery of $73,672,203. The calculation begins with the actual under-recovered balance of $83,117,350 taken from Schedule A2, page 2 of 2, line 13, for the month of June 2014. This balance plus the estimated July through December 2014 monthly true-up calculations comprise the estimated

$73,672,203 under-recovered balance at year-end. The projected December 2014 true-up balance includes interest which is estimated from July through December 2014 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.005% per month.

Q. How does the current fuel price forecast for July through December 2014 compare with the same period forecast used in the Company's 2014 projection filing approved in Order No. PSC-13-0665-FOF-EI?

A. Natural gas costs increased $0.60/mmbtu (11%), coal costs increased $0.47/mmbtu (14%), and light oil decreased $0.49/mmbtu (2%).

Q. Have you made any adjustments to your estimated fuel costs for the period July through December 2014?

A. Yes, we made one adjustment totaling a net reduction of $116,941. We made an adjustment to reduce fuel costs by $116,121 (grossed up to $116,941 from retail to system) for the amortization of interest on the refund pursuant to the Revised and Restated Stipulation and Settlement Agreement approved in Order No. PSC-13-0598-FOF-EI. This adjustment is included on Schedule E1-B (sheet 2), line A5, from July – December 2014.

Q. Were there any impacts to the 2014 Estimated/Actual filing associated with the 2013 Revised and Restated Stipulation and Settlement Agreement (RRSSA)?

A. Yes. Paragraphs 6.a, 7.a, 7.c and 7.d all impact the 2014 Estimated/Actual true-up balance. Paragraph 6.a requires DEF to refund to retail ratepayers the remaining 50% of $258 million, or $129 million, in 2014 through the Fuel Clause. Paragraph 6.a also requires DEF to refund to Residential and General Service Non-Demand customers $10 million in 2014 through the Fuel Clause, allocated 94% to Residential and 6% to General Service Non-Demand. Paragraph 7.a allows DEF to increase fuel rates by $1.00/mWh, or 0.10 ₵/kWh, for the accelerated recovery of the carrying charges associated with the CR3 Regulatory Asset and requires that the increases be added to the fuel factor at secondary metering consistent with the normal fuel projection process. Paragraph 7.c addresses how DEF will credit the final NEIL reimbursement through the Fuel Adjustment Clause. Paragraph 7.d relates to recovery of previously deferred amounts associated with estimated NEIL recoveries. These impacts are addressed further in the testimony below.

Q. Have you included these impacts in your calculation of the 2014 Estimated/Actual true-up balance?

A. Yes.

Q. Please describe where the impact of paragraph 6.a is included in your schedules and how this is included in the Estimated/Actual true-up amount?

A. Exhibit TGF-2, Part 1, Schedule E1-B (Sheets 1 & 2) show the refund of $129 million on line C.1a allocated evenly over the 12 month period. This amount is included in the 2014 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

The 2014 Projection Filing, approved in Commission Order PSC-13-0665-FOF-EI, established the refund of the $10 million through a reduction in 2014 fuel rates for Residential and General Service, Non-Demand ratepayers. The rate reduction is inherently reflected in the Jurisdictional Fuel Revenues reported in Exhibit TGF-2, Part 1, Schedule E1-B (Sheets 1 & 2) on line C.1. The refund of $10 million is shown on line C.1c. This amount is included in the 2014 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

Q. Please describe where the impact of paragraph 7.a is included in your schedules and how this is included in the Estimated/Actual true-up amount?

A. Exhibit TGF-2, Part 1, Schedule E1-B (Sheets 1 & 2) show the fuel adjustment to revenue of $37 million on line C.1b. This amount is removed from the 2014 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

Q. Please describe where the impacts of paragraphs 7.c and 7.d are incorporated into your schedules and how these are included in the Estimated/Actual true-up amount?

A. These adjustments were addressed in DEF's 2013 Final True-Up Filing submitted on March 3, 2014. As explained on pages 9 and 10 of my direct testimony in that filing, the $163 million is simply the net difference between the two paragraphs. The $163 million is included in the $33 million true-up, which is reflected in Exhibit TGF-2, Part 1, Schedule E1-B (Sheets 1 & 2), line C.2. This amount is included in the 2014 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

Q. Does DEF expect to exceed the three-year rolling average gain on non-separated power sales in 2014?

A. Yes, DEF estimates the total gain on non-separated sales during 2014 will be $5,887,982, which exceeds the three-year rolling average of $359,523 by $5,528,459. Consistent with Order No. PSC-01-2371-FOF-EI, shareholders retain 20% of the gains in excess of the three-year rolling average. For 2014, this is estimated to be $1,105,692.

Q. On April 21, 2014, a fire occurred at the Bartow Combined Cycle plant resulting in an outage. Did DEF incur any replacement power costs as a result of this outage?

A. Yes, DEF incurred retail replacement power costs of approximately $12.7 million ($12.9 million system). In June 2014, DEF chose to reduce retail fuel expense by $12.7 million thereby removing the impact of the replacement power to retail ratepayers. This adjustment is included in Exhibit TGF-2, Part 1, Schedule E1-B (Sheet 1), line A5, column June.

Q. On July 7, 2014, a fire occurred at the Hines Combined Cycle plant resulting in an outage. Has DEF incorporated this outage into the fuel forecast used in the 2014 Estimated/Actual True-Up filing?

A. No, when the fuel forecast was generated, the Hines' outage was not contemplated. It is premature to incorporate this event into the fuel forecast.

CAPACITY COST RECOVERY

Q. What is the amount of DEF's 2014 estimated capacity true-up balance and how was it developed?

A. DEF's estimated capacity true-up balance is an under-recovery of $16,991,240. The estimated true-up calculation begins with the actual under-recovered balance of $51,280,618 for the month of June 2014. This balance plus the estimated July through December 2014 monthly true-up calculations comprise the estimated $16,991,240 under-recovered balance at year-end. The projected December 2014 true-up balance includes interest which is estimated from July through December 2014 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.005% per month.

Q. What are the primary drivers of the estimated year-end 2014 capacity under-recovery?

A. The $16,991,240 under-recovery is primarily attributable to $5,720,312 of lower than projected capacity revenues, the 2013 final true-up under-recovery of $6,489,700, and higher projected retail jurisdictional capacity costs of $4,762,429.

Q. Has DEF included the nuclear cost recovery amounts approved in Order No. PSC 13-0665-FOF-EI?

A. Yes, DEF has included $174,226,557 of 2014 recoverable expenses associated with the Levy and CR-3 Uprate projects.

Q. Does this conclude your testimony?

A. Yes.

DUKE ENERGY FLORIDA

DOCKET NO. 140001-EI

Fuel and Capacity Cost Recovery Factors
January through December 2015

DIRECT TESTIMONY OF
Thomas G. Foster

August 22, 2014

Q. Please state your name and business address.

A. My name is Thomas G. Foster. My business address is 299 1st Avenue North, St. Petersburg, Florida 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 140001-EI?

A. Yes, I provided direct testimony on March 3, 2014 and July 25, 2014.

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

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the fuel and capacity cost recovery factors of Duke Energy Florida (DEF or the Company) for the period of January through December 2015.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared Exhibit No.__(TGF-3), consisting of Parts 1, 2 and 3. Part 1 contains DEF's forecast assumptions on fuel costs. Part 2 contains fuel cost recovery (FCR) schedules E1 through E10, H1 and the calculation of the inverted residential fuel rate. I have not included the schedule that supports the rate of return applied to capital projects recovered through the fuel clause pursuant to Order No. PSC-14-0001-PCO-EI, as there are no capital projects for which DEF is requesting recovery in this docket. Part 3 contains capacity cost recovery (CCR) schedules.

FUEL COST RECOVERY CLAUSE

Q. Please describe the fuel cost factors calculated by the Company for the projection period, including the fuel rate adjustment of $1.00/mWh as set forth in paragraph 7.a of the 2013 Revised and Restated Stipulation and Settlement Agreement, approved in Commission Order PSC-13-0598-FOF-EI.

A. Schedule E1 shows the calculation of the Company's jurisdictional fuel cost factor of 4.541 ¢/kWh. This factor consists of a fuel cost for the projection period of 4.33693 ¢/kWh (adjusted for jurisdictional losses), a GPIF reward of 0.00591 ¢/kWh, and an estimated prior period under-recovery true-up of 0.19497 ¢/kWh. Utilizing this factor, Schedule E1-D shows the calculation and supporting data for the Company's levelized fuel cost factors for service taken at secondary, primary, and transmission metering voltage levels. To perform this calculation, effective jurisdictional sales at the secondary level are calculated by applying 1% and 2% metering reduction factors to primary and transmission sales, respectively (forecasted at meter level). This is consistent with the methodology used in the development of the capacity cost recovery factors.

Schedule E1-D, lines 8-10 illustrate the application of the fuel adjustment prescribed in paragraph 7.a of the 2013 Revised and Restated Stipulation and Settlement Agreement (RRSSA) . Pursuant to the RRSSA, an adjustment of $1.00/mWh, or 0.10 ¢/kWh, was added to the fuel factor at secondary metering consistent with the normal fuel projection process. All other fuel factors were developed using this adjusted fuel factor at secondary metering in a manner consistent with their normal derivation.

Schedule E1-D, lines 25-26 show the Company's proposed tiered rates of 4.323 ¢/kWh for the first 1,000 kWh and 5.323 ¢/kWh above 1,000 kWh. These rates are developed in the "Calculation of Inverted Residential Fuel Rates" schedule in Part 2.

Schedule E1-E develops the Time of Use (TOU) multipliers of 1.346 On-peak and 0.837 Off-peak. The multipliers are then applied to the levelized fuel cost factors for each metering voltage level which results in the final TOU fuel factors to be applied to customer bills during the projection period.

Q. What is the amount of the 2014 net true-up that DEF has included in the fuel cost recovery factor for 2015?

A. DEF has included a projected under-recovery of $73,672,203. This amount includes a projected actual/estimated under-recovery for 2014 of $100,906,296 net of the final 2013 true-up over-recovery of $27,234,093 as included in my Direct Testimony filed on March 3, 2014.

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

A. The projected levelized residential fuel factor for 2015 of 4.598 ¢/kWh is an increase of 0.239 ¢/kWh or 5% from the 2014 projected levelized residential fuel factor of 4.359 ¢/kWh.

Q. Were there any impacts to the 2015 Projection filing associated with the 2013 RRSSA?

A. Yes. RRSSA paragraphs 6.a, 6.b, and 7.a all impact the 2015 Projection filing. Paragraph 6.a requires DEF to refund to Residential and General Service Non-Demand customers $10 million in 2015 through the Fuel Clause, allocated 94% to Residential and 6% to General Service Non-Demand. Paragraph 6.b requires DEF to refund to retail ratepayers $40 million in 2015 through the Fuel Clause. Paragraph 7.a, as previously discussed, allows DEF to increase fuel rates by $1.00/mWh, or 0.10 ₵/kWh, for the accelerated recovery of the carrying charge associated with the CR3 Regulatory Asset. Paragraph 7.a. requires that the increase be added to the fuel factor at secondary metering consistent with the normal fuel projection process.

Q. Have you included these impacts in your calculation of 2015 fuel rates?

A. Yes.

Q. Please describe where the impact of paragraph 6.a is included in your schedules.

A. The $10 million refund in 2015 is allocated 94%, or $9.4 million, to the Residential Service rate schedules RS-1, RST-1, RSL-1, RSL-2 and RSS-1. The remaining 6%, or $0.6 million, is allocated to the General Service Non-Demand rate schedules GS-1, GST-1 and GS-2.

The levelized fuel cost factor, prior to the application of this refund and subsequent to the application of the fuel adjustment per paragraph 7.a, is 4.647 ¢/kWh (Schedule E1-D, line 10). To calculate the levelized fuel cost factor for residential service, the above rate is reduced by 0.049 ¢/kWh. The adjustment reflects the rate impact of the $9.4 million refund plus the interest amortization (Schedule E1-D, lines 13-16). The resulting levelized fuel cost factor for residential service is 4.598 ¢/kWh (Schedule E1-D line 17). A similar methodology was used in the calculation of the General Service Non-Demand rate schedules (Schedule E1-D, lines 18-22).

Q. Please describe where the impact of paragraph 6.b is included in your schedules.

A. The impact of paragraph 6.b can be seen in Exhibit TGF-3, Part 2, Schedule E1 line 4. This line shows Adjustments to Fuel Cost for the period of $40.4 million. This is a system amount and includes other adjustments as well as the RRSSA refund. A breakout of this amount can be seen on Schedule RRSSA of Exhibit TGF-3, Part 2. Lines 1-3 show the breakout at the system level, while lines 6-8 show these numbers on a retail basis. Line 6 shows the total retail refund of $40 million. The adjustment to fuel cost on line 4 of Schedule E1 is included in the total cost of generated power on line 5. This amount flows into the total amount to be recovered on line 28. The amount from line 28 on Schedule E1 equals the total amount to be recovered on line 4 of Schedule E1-D. The amount on line 4 of Schedule E1-D, which includes the $40 million refund, is used to develop the fuel rates for 2015.

Q. Please explain the increase in the 2015 fuel factor compared with the 2014 fuel factor.

A. The primary driver of the increase in the 2015 fuel factor is the difference in RRSSA refunds. The 2014 fuel factor included a $129 million refund pursuant to RRSSA paragraph 6.a; this refund represented the final 50% of the $258 million total refund. As discussed in my testimony above, the 2015 fuel factor includes a $40 million refund pursuant to RRSSA paragraph 6.b. The 2015 RRSSA refund is therefore approximately $89 million lower than 2014, thereby resulting in an increase in retail fuel factors. This change in the RRSSA refund results in an increase of the retail fuel factor by approximately 0.237 ¢/kWh.

Q. Have you made any adjustments to your estimated fuel costs for the period January through December 2015?

A. Yes, on Schedule E1, line 4, we made two adjustments totaling a net reduction of $40,353,675. First we made an adjustment to refund $40,000,000 (grossed up to $40,190,452 from retail to system) pursuant to RRSSA paragraph 6.b. We also made an adjustment to reduce fuel costs by $162,209 (grossed up to $163,223 from retail to system) for the amortization of interest on the refunds pursuant to the RRSSA.

Q. Is DEF proposing to continue the tiered rate structure for residential customers?

A. Yes. DEF is proposing to continue use of the inverted rate design for residential fuel factors to encourage energy efficiency and conservation. Specifically, the Company proposes to continue a two-tiered fuel charge whereby the charge for a customer's monthly usage in excess of 1,000 kWh (second tier) is priced one cent per kWh higher than the charge for the customer's usage up to 1,000 kWh (first tier). The 1,000 kWh price change breakpoint is reasonable in that approximately 73% of all residential energy is consumed in the first tier and 27% of all energy is consumed in the second tier. The Company believes the one cent higher per unit price, targeted at the second tier of the residential class' energy consumption, will promote energy efficiency and conservation. This inverted rate design was incorporated in the Company's base rates approved in Order No. PSC-02-0655-AS-EI.

Q. How was the inverted fuel rate calculated?

A. I have included a page in Part 2 of my exhibit that shows the calculation of the fuel cost factors for the two tiers of the residential rate. The two factors are calculated on a revenue neutral basis so that the Company will recover the same fuel costs as it would under the traditional levelized approach. The two-tiered factors are determined by first calculating the amount of revenues that would be generated by the overall levelized residential factor of 4.598 ¢/kWh shown on Schedule E1-D. The two factors are then calculated by allocating the total revenues to the two tiers for residential customers based on the total annual energy usage for each tier.

Q. How do DEF's projected gains on non-separated wholesale energy sales for 2015 compare to the incentive benchmark?

A. The total gain on non-separated sales for 2015 is estimated to be $923,813 which is below the benchmark of $2,204,634. 100% of gains below the benchmark and 80% of gains above the benchmark will be distributed to customers based on the sharing mechanism approved by the Commission in Order No. PSC-00-1744-PAA-EI. Therefore since the total gain on non-separated sales was below the benchmark, none of the gains will be retained for the shareholders. The benchmark was calculated based on the average of actual gains for 2012 of $298,813 and 2013 of $427,107 and estimated gains for 2014 of $5,887,982 in accordance with Order No. PSC-00-1744-PAA-EI.

Q. Please explain the entry on Schedule E1, line 12, "Fuel Cost of Stratified Sales."

A. DEF has several wholesale contracts with SECI. One contract provides for the sale of supplemental energy to supply the portion of their load in excess of SECI's own resources. The fuel costs charged to SECI for supplemental sales are calculated on a "stratified" basis in a manner which recovers the higher cost of intermediate/peaking generation used to provide the energy. There are other contracts with SECI, Reedy Creek and the City of Homestead for fixed amounts of base, intermediate, peaking and plant-specific capacity. DEF is crediting average fuel cost of the appropriate strata in accordance with Order No. PSC-97-0262-FOF-EI. The fuel costs of wholesale sales are normally included in the total cost of fuel and net power transactions used to calculate the average system cost per kWh for fuel adjustment purposes. However, since the fuel costs of the stratified and plant-specific sales are not recovered on an average system cost basis, an adjustment has been made to remove these costs and the related kWh sales from the fuel adjustment calculation in the same manner that interchange sales are removed from the calculation.

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

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

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

A. System sales are forecasted by the DEF Load and Fundamentals Forecasting Department using a sales-weighted median 10-year average of weather conditions at the St. Petersburg, Orlando and Tallahassee weather stations, population projections from the Bureau of Economic and Business Research at the University of Florida, and economic assumptions from Moody’s Analytics.

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

A. The fuel price forecasts for natural gas and fuel oil (residual and distillate) are based on a combination of observable market data in the industry as well as hedges and/or forward contracts currently in place. For coal, a third party forecast is used. Additional details and forecast assumptions are provided in Part 1 of my exhibit.

Q. Are current fuel prices the same as those used in the development of the projected fuel factor?

A. No. Fuel prices can change significantly from day to day, particularly in the storm season. Consistent with past practices, DEF will continue to monitor fuel prices and update the projection filing prior to the October hearing if changes in fuel prices warrant such an update.

Q. On July 7, 2014, a fire occurred at the Hines Combined Cycle plant resulting in an outage. Has DEF incorporated this outage into the fuel forecast used in the 2015 Projection filing?

A. No, the evaluation of the outage at the Hines plant is ongoing; it is premature to incorporate this event into the fuel forecast.

CAPACITY COST RECOVERY CLAUSE

Q. Please explain the schedules that are included in Exhibit__(TGF-3) Part 3.

A. The following schedules are included in my exhibit:

Schedule E12-A – Calculation of Projected Capacity Costs – Year 2015

Page 1 of Schedule E12-A includes estimated 2015 calendar year system capacity payments to qualifying facilities (QF) and other power suppliers, as well as recovery of nuclear costs pursuant to Rule 25-6.0423. The retail portion of the capacity payments is calculated using separation factors consistent with DEF's 2013 RRSSA approved in Order No. PSC-13-0598-FOF-EI. Total nuclear costs are made up of costs for the Levy Nuclear Project and the CR3 Uprate project. 1) Revenue requirements for Levy are calculated by applying the factors in Exhibit 9 of the 2013 RRSSA to the effective sales (kWh) in Exhibit E12-E for the Residential, General Service Non-Demand, General Service 100% Load Factor and Lighting rate classes and to the effective demand (kW) in Exhibit E12-E for General Service Demand, Curtailable and Interruptible rate classes. 2) The revenue requirements for the CR3 Uprate project are as filed with the FPSC in Docket 140009-EI. Schedule E12-A, page 2, provides dates and MWs associated with the QF and purchase power contracts.

Schedule E12-B – Calculation of Estimated/Actual True-Up - Year 2014

Schedule E12-B, which is also included in Exhibit __(TGF-2) to my direct testimony filed on July 25, 2014 in the 2014 estimated/actual true-up filing, calculates the estimated true-up capacity under-recovered balance for calendar year 2014 of $16,991,240. This balance is carried forward to Schedule E12-A, line 34 to be collected from customers from January through December 2015.

Schedule E12-D – Calculation of Energy and Demand Percent by Rate Class

Schedule E12-D is the calculation of the 12CP and 1/13 average demand allocators for each rate class.

Schedule E12-E – Calculation of Capacity Cost Recovery Factors by Rate Class

Schedule E12-E calculates the CCR factors for capacity and CR3 Uprate costs for each rate class based on the 12CP and 1/13 annual average demand allocators from Schedule E12-D. The factors for capacity and CR3 Uprate, excluding Levy, for the Residential, General Service Non-Demand, General Service (GS-2), and Lighting secondary delivery rate class in cents per kWh are calculated by multiplying total recoverable jurisdictional capacity (including revenue taxes) from Schedule E12-A by the class demand allocation factor, and then dividing by estimated effective sales at the secondary metering level. For Levy, the factors are based on Exhibit 9 in the 2013 RRSSA. The revenues were calculated by multiplying the effective sales at secondary metering level for each class by the rates in Exhibit 9. The factors for primary and transmission rate classes reflect the application of metering reduction factors of 1% and 2% from the secondary factor. The factors allocate capacity and CR3 Uprate costs to rate classes in the same manner in which they would be allocated if they were recovered in base rates.

Pursuant to the 2013 RRSSA, DEF has prepared the billing rates for the demand (General Service Demand, Curtailable, and Interruptible) rate classes to be on a kilo-watt (kW) rather than a kilo-watt-hour (kWh) basis. These changes are reflected in columns 11 – 16.

Q. Has DEF used the most recent load research information in the development of its capacity cost allocation factors?

A. Yes. The 12CP load factor relationships from DEF's most recent load research conducted for the period April 2011 through March 2012 are incorporated into the capacity cost allocation factors. This information is included in DEF's Load Research Report filed with the Commission on July 31, 2012.

Q. What is the 2015 projected average retail CCR factor?

A. The 2015 average retail CCR factor is 1.351 ¢/kWh, made up of capacity and nuclear costs of 0.901 ¢/kWh and 0.450 ¢/kWh, respectively.

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

A. The total projected average retail CCR factor of 1.351 ¢/kWh is 0.022 ¢/kWh or 2% lower than the 2014 factor of 1.373 ¢/kWh. This decrease is primarily attributable to a reduction in nuclear recoveries of $5,094,859.

Q. Does this conclude your testimony?

A. Yes

BY MR. BERNIER:

Q Mr. Foster, do you have a summary of your prefiled testimony?

A Yes, I do.

Q Will you please summarize your prefiled testimony for the Commission?

A Yes. My name is Thomas Foster, and my testimony is addressing Duke Energy Florida's actual fuel and capacity cost recovery true-up amounts for the period of January through December 2013, estimated actual amounts for the period of January through December 2014, and projection amounts for 2015. I'm available for any questions you may have.

MR. BERNIER: Mr. Chairman, we tender Mr. Foster for cross-examination.

CHAIRMAN GRAHAM: Thank you very much.

Mr. Rehwinkel.

MR. REHWINKEL: Thank you, Mr. Chairman. Before we get started, I have three exhibits that I would like to use in cross-examination. I've given them to staff. It might be better if we just pass them all out at one time. I've given a copy to the witness and his counsel. So if we can do that now, that might help.

While they're passing them out, let me tell you what they are. The first exhibit is one that we used last year in last year's hearing, and it is, it is an excerpt from the revised and restated stipulation and settlement agreement. So it's entitled RRSSA Excerpt.

CHAIRMAN GRAHAM: Say that again please.

MR. REHWINKEL: The title of it is RRSSA Excerpt.

CHAIRMAN GRAHAM: We will give that hearing ID number 69.

(Exhibit Number 69 marked for identification.)

MR. REHWINKEL: Okay. The second exhibit is DEF's Summary of NEIL Reimbursement. N-E-I-L, all caps, Reimbursement.

CHAIRMAN GRAHAM: We will give that an identification number of number 70.

(Exhibit Number 70 marked for identification.)

MR. REHWINKEL: Okay. And the last exhibit is entitled Fuel Cost Recovery Schedules.

CHAIRMAN GRAHAM: And that will have a number of number 71.

(Exhibit Number 71 marked for identification.)

MR. REHWINKEL: Mr. Chairman, with respect to the last schedule, Exhibit Number 71, what I have done is taken the fuel schedules from Mr. Foster's August 22nd, July 25th, and I believe March, early March, March 1st testimony and made a composite exhibit because we're going to go through those. I'm going to ask him on the record if these are true and correct copies of those portions of his testimony exhibits. And I would like, even though they're already in the record stipulated, to make it an exhibit because it would be easier to go through using Bates pages than to cumbersomely reference the titles of the exhibits. And I've talked to the company; they're okay with that, if that's okay with the Commission.

CHAIRMAN GRAHAM: I like the idea. I think it makes it a lot simpler.

MR. REHWINKEL: Okay. Thank you. I think all the exhibits have been passed out.

EXAMINATION

BY MR. REHWINKEL:

Q So good morning, Mr. Foster.

A Good morning.

Q My name is Charles Rehwinkel with the Office of Public Counsel. And you are the witness designated to present the accounting for and the development of the 2015 fuel factors; right?

A Yes, sir.

Q And as part of the development of the factor, you also present the cumulative effects of the ongoing true-ups that are part of the fuel and capacity clause process; is that right?

A Yes.

Q Okay. My questions today to you are to explore on the record the mechanics of the fuel factor and its development as a means of flowing the benefits and impacts of the recently approved revised and restated Stipulation and Settlement Agreement -- or RRSSA -- to the customers. Do you understand that?

A Yes.

Q And I also want to ask you about the treatment of the replacement power costs incurred due to two outages in 2014. And are you the appropriate person to ask about whether such costs are included in the true-up and projection filings of Duke this year?

A Yes.

Q Okay. Now you are generally familiar with the RRSSA provisions that impact the fuel clause in paragraphs 6 and 7; is that right?

A Yes.

Q And you have the exhibit which has been identified as Exhibit 69; correct?

A Yes.

Q Would you agree with me that the RRSSA calls for the three types of benefits or impacts to be flowed to customers via the fuel clause?

A Yes.

Q NEIL insurance proceeds in the amount of $490 million which when added to the previously received $151 million totaled $641 million retail. Is that correct?

A That's approximately correct. Yes.

Q Okay. And I believe $3 million of that 641 was actually, went to the capacity clause; is that right?

A Yes, that's correct.

Q Okay. Also, the RRSSA called for refunds in the amount of $388 million to be flowed through the fuel clause; is that right?

A Yes.

Q This would be $129 million in 2013; right? Another $129 million in 2014 to all retail customers.

A Yes.

Q $10 million in 2014 to just residential and general service customers.

A Yes.

Q $10 million in 2015 to residential and general service customers.

A Yes.

Q $40 million in 2015 to all retail customers?

A Yes.

Q $10 million to be refunded in 2016 to residential and general service customers.

A Yes.

Q And $60 million in 2016 to all retail customers; is that right?

A Yes.

Q And those numbers I read off total $388 million; right?

A Yes.

Q And if I add the $388 million to the $641 million of NEIL refunds, that's a total of $1,000,029,000 [sic] or $1,000,026,000 [sic] through just fuel that are being refunded to customers through the clause; is that right?

A I think you said thousand and maybe meant million?

Q Million, yes, that's what I meant.

A Yes, that sounds right.

Q $1.029 billion and $1.026 billion, those are the right numbers? Okay.

And, in addition, there are also three separate standalone rate adjustments of $1 per 1,000 kilowatt hours, $1 per 1,000 kilowatt hours, and $1.50 per 1,000 kilowatt hours in 2014, '15, and '16 respectively.

A That's correct.

Q And those are in paragraph 7 of the RRSSA; is that right?

A I think it's paragraph 7. Subject to check, I'll accept that.

Q Okay. Now the rate adjustments of $1, $1, and $1.50, they are targeted for early recovery of the CR3 retired asset in order to reduce the accumulation of carrying costs; is that right?

A Yes. That's my understanding.

Q Okay. Is it your testimony here today that Duke's determination of the 2015 factor as shown in your prefiled testimony and schedules incorporates the elements including true-ups of each of these impacts except for the $70 million of refunds that are scheduled for 2016?

A Yes.

Q Is it also Duke's position that 100 percent of these benefits and impacts will be and are being accurately reflected in rates since 2010 and will be through 2016 and for as long as true-ups are required?

A Yes.

Q Okay. Do you have a copy of Exhibit 70 before you, the NEIL exhibit?

A I do, yes.

Q Okay. And before I get to that actually, do you have a copy of Exhibit 71 also?

A Yes.

Q The 50-page Bate stamped exhibit.

A Yes.

Q Can you agree with me that the schedules here are the fuel schedules attached to your March, August -- July and August testimonies? Specifically for, I guess for your August testimony, TGF-3, part 2, have I included all of TGF-3, part 2?

A I'm not sure if you've included all of it. I didn't get a chance to look at that.

Q Okay. I apologize.

A But I can, I can agree that what you've included are consistent with what we filed.

Q If you look at Bates pages 1 through 37 of Exhibit 71 --

A Yes.

Q -- does that appear to be all of part 2?

A It looks like it, yes.

Q Okay. And for your July testimony, TGF-2, part 1 --

A Uh-huh.

Q -- do you see that there? Is that included correctly?

A Yes.

Q And for your March testimony, TGF-1T, is that the fuel related schedule for your 2013 true-up?

A Yes.

Q Okay. So Bates pages 1 through 50 are the relevant fuel schedules -- 1 through 51 are the relevant fuel schedules from those three pieces of testimony?

A Well, they're the ones included in this exhibit.

Q Yes. Okay. Let's go back to Exhibit 70, the NEIL exhibit. You're familiar with this document because you assisted putting it together for last year's hearing; right?

A Yes.

Q Okay. And it's still accurate. There's nothing about it that has changed, is there?

A That's correct.

Q Okay. Now as shown in Exhibit 70, Duke began receiving and flowing through the NEIL insurance proceeds to customers beginning in 2010; right?

A That's correct.

Q And that concluded in 2013, subject to true-up; right?

A That's correct.

Q Now this exhibit shows the total and the retail distribution of the entire $835 million that were received from NEIL for claims related to the CR3 outage; right?

A Yes.

Q And it shows that a total of $641 million in NEIL proceeds were to have been returned to the retail customers through the fuel clause. That's $762 million retail minus $121 that went to, as a credit in plant; is that right?

A That's correct.

Q And the final payment from NEIL of $490 million was made in May of 2013 and is reflected in the true-up schedules that you have filed; is that right?

A That's correct.

Q Okay. And this process is to have been concluded by the end of 2014 subject to any final true-up that may be required; is that right?

A That's correct. Yes.

Q Okay. Can you turn to Exhibit 71, and I want you to turn to pages -- I'm going to get you to turn to 50, 42, and 6, but let's go to page 50 first.

A I'm there.

Q And this is the schedule that summarizes, that you prepared for this hearing cycle, that summarizes the RRSSA impacts or refund impacts that are reflected in your fuel clause, in your fuel filing; right?

A That's correct.

Q And if I look in May of 2013, you show the $490 million in the retail side, portion of that schedule at the bottom; right?

A That's correct.

Q Okay. Now that number in the top, it's jurisdictionalized on a system basis; is that right?

A Yes. It was grossed up to make sure that when it got to the retail basis, we got to the right number.

Q Okay. So the -- if you look in the system column, there's $515,447 -- it looks like -- 496.

A I'm sorry. What are you looking --

Q In the 12-month period column of line three of that, of that page.

A Oh, yes, I'm with you. Yes.

Q Okay. And your testimony is that this number represents this number taken down to the retail, which is 515,131,829; is that right?

A I think it says 513, but they're a little --

Q 513, yes. That number is the, reflects the entire $490 being refunded to residential -- to retail customers; right?

A Yes, sir.

Q Okay. Now if I go to page 45 of this exhibit --

A I'm there.

Q -- the $490 million is, resides in the May column on line A5; is that right?

A That's correct.

Q It's embedded in that $497,107,752?

A That's correct.

Q And if I turn over to page 46, in the 12-month period column, line A5, I see the 515,447,495 system number.

A That's correct.

Q That's right?

And when it gets jurisdictionalized in this schedule to retail, it equates to the 490.

A That's correct.

Q $490 million number.

Now this schedule here on page 46 is your final true-up for 2013; is that right?

A That's correct.

Q And the 515, which we've demonstrated includes the entire amount of the NEIL refund, it rolls up to the bottom line, line 13, in the 12-month period for an under recovery for that period of $5,961,090; is that right?

A That's right.

Q Okay. Also on page 46 on line C1A, you show

$129 million in jurisdictional fuel recovery revenue; is that right?

A That's correct.

Q Now this is the true-up of the first $129 million refund or half of the $258 million called for under the -- to all retail customers under the RRSSA; is that right?

A Yes.

Q And that $129 million was part of your 2012 development of the 2013 fuel factor, is that right, that first installment?

A Yes.

Q Okay. Both of these numbers, the 490 and the 129, are, as shown in this schedule, embedded in the final 2013 true-up under recovery of $5,961,090; is that right?

A That's correct.

Q Okay. Now on page 48, can you explain to me the difference between that schedule and the schedule that we just described? This is the 2013 estimated actual.

A This is what would have been filed last year as our estimated actual filing. There's -- a lot of things can change within it. I believe in this one you had the -- I'm trying to remember.

Q Well, let me ask --
A The 129 was in with the adjustments to fuel cost.
Q Okay. Let me ask it this way.
A Yes.
Q The 129 and the 490 are both reflected in the $33,195,183; is that right?
A The $33 million. Yes.
Q It's on line 13.
A That's correct.
Q I called this an under recovery, but these are over -- are these over recoveries?
A This?
Q The 33.
A This is an under recovery.
Q Okay. All right. Now the true-ups that we described, the estimated actual that shows 33,195,183 and then the final true-up of $5,961,090, those numbers are further embedded in the overall or net true-up that you present on page, on Bates page 3 of Exhibit 71; is that right?
A Could you just say it one more time? I'm sorry.
Q Yeah. If you could go to Bate's page 3.
A Uh-huh.

Q We see on line 1 the 5,961,090. Now that's shown as a negative, which is an under recovery.

A So if I could, because I think I see where you're going.

Q Yeah.

A So we had expected in '13 to be $33 million under recovered and baked that into rates for '14. We ended up, you know, closer to $6 million under recovered, which bakes into '14 a $27 million over recovery that we'd have to flow back. And that's the net of that 33 and 5 in lines 2 and 1 respectively.

Q Okay. And in your testimony you refer to a $27 million over recovery.

A Yes.

Q And that's the net of these two numbers; right?

A Yes. Yes.

Q So what you're reflecting here on lines 1 and 2 of Bates page 3 are the final results of 2013.

A That's accurate.

Q That include all of the NEIL money and the first $129 million of the, of the two-part $258 million refund.

A Yes.

Q Okay. And that -- those numbers also in turn are embedded in the $5 -- the 4.51 -- the 4.541 2015 fuel factor that you developed on Bates page 2; is that right?

A Yes, that's correct.

Q Okay. Because we see on Bates page 2, line 23, in the dollars column, that 73,672,203 number, which is the -- well, I'm kind of getting ahead of myself. We'll come back to that.

Well, they're embedded in the -- well, let's look at Bates 3. You, what you show here is the final effects of 2013 in lines 1 and 2, and then you have calculated an estimated under recovery of 100,906,296 for 2014. And the net of that is 73,672,203; is that right?

A That's correct.

Q And if we look on Bates page 2, that 73,672,203 is on line 23, and it rolls all the way down to the development of the total fuel expenses to be recovered, and the factor for that is 4.541. Is that right?

A That's correct.

Q Okay. So just to summarize, the 490 and the first 129, what we've gone through so far shows that those numbers have been completely accounted for and flowed through to the customers based on the presentation in your schedules.

A That's accurate.

Q Okay. Or they will be by the end of 2014.

A Yes. Yes.

Q Let's go to Bates page 6, if you will.

A I'm there.

Q Okay. Now on this page you show -- this is the RRSSA schedule for 2015; right?

A Yes.

Q And the only specific RRSSA adjustment that you show here -- well, there's two. You have a refund of $40 million, and that's the one we discussed earlier that is called for for all retail customers in 2014.

A Yes.

Q And what this schedule shows is that you jurisdiction -- you gross it up the system and then you bring it back down to retail plus some interest; right?

A Right.

Q And you also have on line 10, line 10 is the dollar for early recovery called for in 2015; correct?

A That's correct.

Q Okay. And the amount of that is $37,785,590. That's the projected recovery that would be yielded by that dollar times the projected sales units for 2015; right?

A That's correct.

Q Okay. Now the 40 million, if you look on line 3 of this schedule, the $40,353,675.

A Yes.

Q Okay. In the 12-month column, that number is included in Bates page 2, I believe, line 4.

A That's accurate. Yes.

Q Okay. And this shows again that it is embedded in the calculation that yields the fuel factor of 4.541?

A Yes.

Q Okay. Now what's not on this schedule is any impact, if we go back to Bates page 6, any impact of line 10, which is the $1 adjustment for early recovery of CR3; correct?

A That's correct.

Q Because that number is added in on Bates page 8, because what you do is if you look on line 6, there's your 4.541, and that was a number that was developed --

A Correct. On Bates page 2.

Q Correct. And what you've done is you've taken that factor and you've spread it based on the various metering points. Well, first of all, you add on line 9, that's where we see the $1.

A Yes.

Q It comes in as a .100 cents per kilowatt hour. That's a dollar right there.

A Correct. Correct.

Q So that gets added and it becomes 4.641.

A 47, I think. So if I, if I could, Mr. Rehwinkel.

Q Okay.

A From line, from line 6 to 8 nothing changed. That's the way it's always been presented.

Q Okay.

A And then you take -- typically line 8 would just be multiplied by a factor to get to the line 10, 11, and 12 numbers. Right? In this case, we had to add that 1 cent per kWh to get to 10, which lines 11 and 12 are based off of. So the math, other than adding that cent per kWh there, the math is the same as always.

Q Okay. So what you do is you get that factor, you add in the dollar.

A Correct.

Q And then you adjust it based on the different types of customer class metering arrangements --

A Yes, sir.

Q -- that are called for by the stipulation or Commission orders; right?

A Exactly.

Q All right. And then what you do from that point is you go to lines 13 through 17 and you take the factor that you have developed, and I guess it is the 4.647?

A Yes.

Q That number, you reduce it to refund the 94 percent of the 10 million to residential retail customers.

A Correct.

Q And then on lines 18 through 24 you do the same thing with -- I'm not sure which factor you take it and you give the general service customers their 6 percent of that 10 million.

A That's correct. Yes.

Q Okay. So we've got to talk about 2014, but this is basically showing that you've -- so what we've done so far is you've gone through and fully accounted for the 490 and the first 129, the 40 million and the 10 million and the dollar rate adjustment.

A That's correct.

Q Okay. So we -- all right.

Just a quick question about -- if we go back to exhibit, I mean, Exhibit 71, Bates 2.

A Okay.

Q This is kind of the obvious thing, but the --

you show your fuel costs, your projected fuel costs on line 1, 1.45 billion; right?

A Correct.

Q And your total cost is 1.410 because you reduced it by $40 million.

A That's correct.

Q So without this $40 million refund you would use the number on line 1; right?

A That's correct.

Q And that simple concept applies to all of the 1,029,000,000 -- or 26 million dollars that we've referred to in prior testimony. They all have reduced fuel costs dollar for dollar based on that amount.

A That's correct. All --

Q Or they will have by the end of 2016.

A Correct.

Q Okay. Can you turn to -- let's go to Bates 8 again real quick.

A I'm there.

Q All right. The -- for 2015 on line 7 you're projecting 37,798,631 megawatt hours of sales; is that right?

A 37,738,631. But, yes, I agree.

Q 738. Okay. So that number is what you expect to yield, the $1 to yield is 37,738,631 for 2015; is that right?

A Yes. Roughly 37 million, yeah, 38.

Q All right. And the same would apply, whatever your -- when you -- if I could get you to go back to Bates 41.

A I'm there.

Q On line 21, for 2014 you originally projected 37,664,779 megawatt hours of sales; is that right?

A Yes.

Q And you ended up -- well, you think, based on your best projection, your estimated actual projection, that you're going to sell 37,165,665 megawatt hours.

A Correct.

Q Which is 499,114 megawatt hours less than what you originally projected.

A Correct.

Q Now for 2014, when you prepared your factor for 2015, you used the 37,664,779 number to collect the $1.

A Yes. That's what we would have used.

Q Okay. You also used that number to refund the $129 million called for, the second installment of the $258 million; right?

A Yes. That's accurate.

Q Okay. Okay. Now there's -- what you are doing, if I could get you to turn -- well, can you explain to me if you, if you project sales using a higher number of units and your sales are lower and you're using those units to refund a fixed number like $129 million, at the end of the year, if you take no further action, you will refund less than $129 million mathematically speaking; correct?

A Yes, mathematically speaking. Agreed.

Q Okay. But the way I read your schedules and your testimony is that's not what will happen, because on the page before that, page 40, your true-up schedule handles that issue, I believe. And can you describe how it does?

A Well, certainly. And I think you're looking at lines, at line C, basically the C section there with lines 1A through 1C.

Q Yes.

A And you can see in, for instance, in 1A we're reflecting an increase in revenues associated with $129 million to make sure that, exactly to your point, we don't have a mismatch just due to sales and then one way or the other you either over or under collect.

Q So what this does, I think what the math does on this schedule, and I want to make sure I understand this on the record, is that by using the 129 to calculate what this schedule calculated, which is a true-up --

A Uh-huh.

Q -- you're basically giving the customers credit for having gotten the whole $129 million back.

A That's correct.

Q Which means that when you evaluate whether you've recovered your costs, which are the numbers from lines A and B -- which are in Sections A and B; right?

A A.

Q Well, actually no, it's A. You don't offset costs by an under refund of the $129 million.

A Some lesser amount. Correct.

Q Okay. So we didn't talk about 2014, but if you look at the 2014 RRSSA schedule, which is on 42 --

A I'm there.

Q -- this shows the $129 million in line 1 and the $10 million in line 2; right? And those numbers are reflected as revenue in your true-up calculation that we discussed on page 40; right?

A Yes. I think it was line 2 and 3.

Q That's what I meant, 2 and 3.

A But yes.

Q Yes. You have -- what is on line 1, the final NEIL reimbursement? What is that?

A That just reflects the difference between the roughly $326 million assumed to be received from NEIL when 2013 rates were set as compared to the 490 approximately million actually received. So that's just to illustrate that the amounts referenced in paragraph 7C and 7D are, in fact, included.

Q Okay. And on line 6, this is the first dollar, correct --

A That's correct.

Q -- for 2014? And it shows that you were projecting to recover 37,165,565.

A That's correct.

Q And that number is shown on 40, line 1C, 1B.

A Yes.

Q Okay. Now you reflected at the, you reflected at the originally projected level, but what you actually earned on that dollar -- well, no. This is your new number. So this is what you're showing you're actually going to collect.

A Yeah.

Q So you've done, you've done -- you've used here not what you originally projected you were going to collect but what you now think you will collect.

A Our current estimate. Yes. That's correct.

Q Okay. All right. All right. So just to recap, if you go back to Exhibit 69 and 70, they are, they are the total representation of the refunds and rate adjustments that are called for under the RRSSA, the three types we talked about, the 388, the NEIL numbers, and the early recovery rate adjustment; right? Those two exhibits cover it all.

A 69 is, of course, the settlement agreement, so that covers it.

Q Yeah.

A Yeah. Yes, sir.

Q All right. Okay. Let's go and turn to the outages. Do you have your July 25th testimony?

I think we're finished with the exhibits, Commissioners.

A Let me set these to the side. July 25th, you said?

Q Yes.

A I'm there.

Q All right. Now you talk about two outages here on page 7.

A That's correct.

Q And on lines 9 through 16 you testify that -- well, first of all, let me make sure -- let me do this. This was an unplanned outage at the Bartow plant that occurred on April 21st; right?

A Yes.

Q And you're not here to testify about anything other than the accounting for that issue; is that right?

A That's correct.

Q Okay. And I think you reference in your testimony that, on these lines that there is an adjustment on TGF-2, part 1, Schedule A1B, sheet 1, line A5, which for refence is Bates page 4 of Exhibit 71 that I said I'm finished with, but that's where you reflect the $12.9 million on a system basis. It's, I think, $12.878 million as an adjustment or a reduction in fuel costs in June; is that right?

A That's where we reflect that adjustment. That's correct.

Q Okay. That's just -- the delay there is because that's just the time it took you from the outage to calculate replacement power costs?

A Until it returned from the outage we couldn't calculate them.

Q Okay.

A So I think it came back on in early June.

Q Okay. So your testimony states that, on line 13 through 15, DEF chose to reduce fuel expense by $12.7 million, thereby removing the impact of the replacement power to retail ratepayers; right?

A That's correct.

Q And the $12.7 million is your retail jurisdiction amount; right?

A That's correct. Yes.

Q Your testimony, as I read it, does not admit or address an issue of imprudence.

A That's correct.

Q Okay. But nevertheless we can read your testimony and take your testimony here today that the company's sworn representation is that these costs, the $12.7 million, will be absorbed by shareholders and never submitted for recovery from customers.

A Yes. We're never going to submit these for recovery through our fuel clause.

Q Okay. Is it also your testimony that to the best of your's and the company's knowledge and belief that the $12.9 million represents all of the cost of replacement power caused by the April 21st, 2014, incident and outage at the Bartow plant?

A Yes.

Q Your testimony does not address any rate base accounting for repairs or capital additions, if any, that would be recorded at the Bartow plant as a result of the outage, does it?

A No, just the replacement power.

Q Likewise, you're not here to testify about the accounting for any insurance proceeds received by Duke or claimed by Duke as a result of the outage, if there are any.

A Correct.

Q And your testimony does not come with a qualifier that the Commission cannot inquire into the circumstances of the outage to ascertain whether customers are incurring costs related to base rate recovery or any other rate impact like environmental cost recovery or another clause; right?

A Correct.

Q Likewise, if the Commission were to audit your fuel expense and find other replacement power costs related to the outage that were not included here, they would not be foreclosed from making a true-up adjustment, would they?

A Correct.

Q On that same page 7 you testify about an unplanned outage at the Hines combined cycle unit; correct?

A Yes.

Q You testified that that event was not incorporated into the fuel forecast; right?

A Yeah, that's correct. There's no replacement power cost incorporated into these fuel projections.

Q And that's because July 7th was too late in the year to impact your estimated actual forecast?

A That's correct. The event occurred at a time when we were, in order to be able to file testimony and schedules, there just wasn't time to rerun everything, and it was just a had just happened type of --

Q Okay. So that means that there are no replacement power costs included in the factor that Duke proposes to the Commission to adopt for 2015; right?

A That's accurate.

Q And as a corollary to that, there are no adjustments made to remove any costs either.

A That's also true.

Q Okay. But to contrast the Hines to the Bartow situation, your testimony provides no representation or testimony whatsoever about whether Duke will seek to recover replacement power costs for the Hines outage in 2016; right?

A No, it does not.

MR. REHWINKEL: Okay. Thank you. Those are all the questions I have. Thank you for appearing.

Thank you, Commissioners.

CHAIRMAN GRAHAM: Thank you, Mr. Rehwinkel.

Any other Intervenors for questions of this witness?

Staff?

MS. BARRERA: Commissioners, staff will note that the parties have waived filing briefs for the contested issues.

CHAIRMAN GRAHAM: No. Do you have any questions of this witness?

MS. BARRERA: Oh, I'm sorry. No. I'm just looking at the script.

CHAIRMAN GRAHAM: Commissioners, any questions of this witness?

Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman. And thank you, Mr. Foster, for your testimony.

I have a quick question concerning the $1 associated with the 2013 settlement. And you indicated in your testimony it's for the accelerated recovery of carrying charges associated with the CR3 regulatory asset.

THE WITNESS: Yes, sir.

COMMISSIONER BALBIS: What is the amount, the total amount that's remaining for the carrying charges for the regulatory asset? Do you know that?

THE WITNESS: I do not have that number as I sit here today. I'm sure we could get it though, if it's something the Commission would like.

COMMISSIONER BALBIS: I'm just curious because I couldn't find that in your testimony. So you just applied the $1 in accordance with the --

THE WITNESS: Yes. So -- and so on kind of my side of -- I don't really work with that specific reg asset. But on our side, you know, we're collecting it, and there is absolutely a side that's making sure it's applied and going to reduce the balance of that reg asset.

COMMISSIONER BALBIS: Okay. But you don't know what the $37 million plus or minus, what amount that's specifically writing down; correct?

THE WITNESS: The total amount of the reg, I don't know that as I sit here today. But, again, we can certainly get that if it's something the Commission would like.

COMMISSIONER BALBIS: Okay. Thank you.

CHAIRMAN GRAHAM: Any other Commissioners? Is there any redirect?

MR. BERNIER: None, Mr. Chairman.

CHAIRMAN GRAHAM: Okay. Let's look at your exhibits, which ones we need to enter into the record.

MR. REHWINKEL: Everything is stipulated except for 69 through 71 for Mr. Foster.

MR. BERNIER: I'm not sure that we moved 19 through 24.

CHAIRMAN GRAHAM: I don't think that we moved his Exhibits 19 through 24 into the record yet.

MR. BERNIER: And we would move that at this time, Mr. Chairman.

(Exhibits 19 through 24 admitted into the record.)

CHAIRMAN GRAHAM: Okay. And Mr. Rehwinkel.

MR. REHWINKEL: I would move 69 through 71.

CHAIRMAN GRAHAM: And we'll also move 69, 70, and 71 into the record. Okay.

(Exhibits 69 through 71 admitted into the record.)

MR. REHWINKEL: Mr. Chairman, if it would be your pleasure, and we didn't discuss this, I have 30 seconds of a closing to make, if you would like, if it would help you. I mean, we've waived a brief, but I could give you a statement based on the conclusion of this if it would be helpful to the Commission.

CHAIRMAN GRAHAM: I don't have a problem. Let me check with Duke.

MR. BERNIER: We have no problem with that.

CHAIRMAN GRAHAM: Staff?

MS. BARRERA: No problem.

CHAIRMAN GRAHAM: The floor is yours.

MR. REHWINKEL: Thank you, Commissioner. And thank you for the opportunity to address you in brief closing remarks in lieu of filing a post-hearing statement.

After the opportunity to ask questions of Mr. Foster, which we really appreciate, and the opportunity to consider the answers that he gave, the Public Counsel is satisfied that, based on the testimony of Mr. Foster, that we have no objections to voice here now as to the fuel factor proposed by Duke insofar as the refund and rate adjustments and replacement power decisions that are incorporated in it or have a bearing upon that factor.

Of course, we make no statement on the overall cost or components of the cost that Duke has the burden to justify before the Commission. That's a judgment that you will ultimately have to make. But we're satisfied with the questions that we asked, so thank you.

CHAIRMAN GRAHAM: Thank you, Mr. Rehwinkel.

Staff, where are we?

MS. BARRERA: We're at the part where I say that --

CHAIRMAN GRAHAM: Oh, that part again.

(Laughter.)

MS. BARRERA: Yes, I'll say it again. The parties have waived filing briefs for the contested issues 1C, 10, and 11. Okay. And since no briefs are requested, staff is prepared to make an oral recommendation at this time, should the Commission decide. We're also available to answer any questions.

CHAIRMAN GRAHAM: Commissioners, any further questions of staff, or are we ready to make a bench decision?

Commissioner Edgar.

COMMISSIONER EDGAR: I would just say, Mr. Chairman, that if staff is prepared to make an oral recommendation, I would like to hear it.

MS. BARRERA: We'll first hear from Mr. Lester.

MR. LESTER: Commissioners, I'm Pete Lester with staff.

Issues 10 and 11 for Duke address the true-up and projection amounts to be collected in 2015. These issues have remained open so that the refunds and adjustments required by the revised and restated stipulation and settlement agreement can be verified.

Staff's recommendation for Issues 10 and 11 is the appropriate amounts for Duke Energy Florida are as reflected by the company in the prehearing order. Duke Energy Florida has correctly made the necessary adjustments and refunds pursuant to the revised and restated stipulation agreement filed in Docket Number 130208 and approved by the Commission by Order Number PSC-13-0598-FOF-EI.

MS. BARRERA: Mr. Michael Barrett is ready to make the recommendation for Issue 1C.

MR. BARRETT: Good morning, Commissioners. I'm Michael Barrett with staff.

Issue 1C addresses whether Duke has made the appropriate adjustments to its fuel costs to account for replacement power associated with the fire that occurred in April at the Bartow unit.

Duke has made an adjustment to remove the impact of replacement power costs to its retail customers, and staff has verified that Duke is not seeking recovery of replacement power costs associated with this event.

Staff recommends that Duke has made the appropriate adjustments to account for replacement power costs associated with the April 2014 forced outage at the Bartow unit.

CHAIRMAN GRAHAM: Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman.

I have a question or two for staff, and it's concerning the $1, the application of the $1 to 1,000 kilowatt hour usage.

And my main concern is that that allows the company to recover about $37 million. Has staff found anything in the record that indicates the amount of carrying costs that are associated with a regulatory asset and what these $37 million would be applied to so that we can be comfortable that it is appropriate?

MR. LESTER: Right now, no, sir. I don't have a handle on the total amount of the regulatory asset.

COMMISSIONER BALBIS: I'm sorry. I didn't catch that last part.

MR. LESTER: I don't have -- I don't -- I don't know the total amount of the regulatory asset.

COMMISSIONER BALBIS: How about the carrying charges?

MR. LESTER: The carrying charges.

COMMISSIONER BALBIS: I know that the witness indicated that that information could be provided to us, but if we're poised to make a bench decision on that, that's the concern that I have is that, you know, obviously the $1 was associated with the settlement agreement, which I did not support for a number of reasons, but the primary one being a lack of evidence in the record. And so I'm wondering if staff has information that I may have overlooked in the testimony that indicates that.

MR. LESTER: We don't have the -- I think it was Exhibit 10 on the, to the agreement where they have the amount of the -- we don't have that amount filled out.

COMMISSIONER BALBIS: Okay. Thank you.

CHAIRMAN GRAHAM: Ms. Triplett, yes, please.

MS. TRIPLETT: Thank you, Mr. Chairman.

If it helps, as I understand the settlement and the $1 charge, that is an implementation that goes to the fuel clause. But when we go to put the regulatory asset into rates per the settlement, which will happen in the future, at that point there will be a full opportunity to true everything up, including the carrying charges, what the status of the reg asset is at that point in time, and, you know, anything else that's impacting the value of okay.

COMMISSIONER BALBIS: Okay. Thank you, Mr. Chairman. If I may interact with Ms. Triplett.

And I appreciate that. So what accounting mechanism is in place at this time? Because all I've seen in this docket is just the $1 being applied as shown in Mr. Foster's testimony. So what accounting mechanism is in place so that in the future we can make sure that everything has been accounted for?

MS. TRIPLETT: I believe that there is a filing that we make -- I think this is part of our earnings surveillance. I think it's on a quarterly basis. I don't have the details of it, but I know that we provide what the -- where the reg asset stands. And I think that perhaps as part of that there would be an inclusion of what are the carrying charges as compared to the rest of the components of the regulatory asset.

But then in addition, as Mr. Foster indicated, there are other folks in his group that are accounting for that regulatory asset. And, again, at the point in time when we go to move it into base rates, then that would be -- the Commission and the staff and all of the signatories to the settlement would have the opportunity to look at all of those accounting numbers.

COMMISSIONER BALBIS: Okay. And then during last year's deliberations and discussion on the cap for the regulatory asset, which I believe is $1.4 billion, it was more of an estimate. Does Duke have any additional information as to a range, you know, what the estimated amount of the regulatory asset is? Is it close to that 1.4 billion?

MS. TRIPLETT: I wouldn't want to speculate, but I believe that it is tracking right around, but I wouldn't want to speculate. And I think that that filing that I referenced, which I don't have here today, provides a status as far as where things stand with the part of the regulatory asset subject to the cap, the 1.4 billion, in addition to the associated costs as well, which are not subject to the cap.

COMMISSIONER BALBIS: Okay. And then a follow-up question for staff. Maybe you can help with this. If we were to assume that the regulatory asset is what was estimated previously and Ms. Triplett confirmed, around $1.4 billion, would the carrying costs be associated with that full amount? And if so, what would the annual estimated amount of that be? Is it close to 37 million? Is it more? Is it less?

MR. LESTER: I'm sorry, Commissioner. I just don't know. I really need to see more, investigate it further.

COMMISSIONER BALBIS: Okay. And then Ms. Triplett described an accounting mechanism through the earnings reports perhaps. What is staff's understanding as to how this amount is going to be tracked and accounted for going forward?

MR. LESTER: Again, I'm sorry. I haven't really prepared -- I'm not prepared on that.

COMMISSIONER BALBIS: Okay. Well, then, you know, Commissioners, my concern is that we track the $37 million. And then if at the end of the day if that was more or less, et cetera, that we can make sure that customers weren't paying too much for something. There seems to be a lack of evidence in the record now. I know this is ongoing.

I am comforted by some of the comments Ms. Triplett made. I'm concerned that staff is unsure. So I'm hoping that moving forward that staff and the parties can make sure we come up with an accounting mechanism so that these, we can make sure that these charges are appropriate.

CHAIRMAN GRAHAM: I see Mr. Foster over there chomping at the bit. Did you have something to add?

THE WITNESS: Thank you, Commissioner, Chairman. No. I was just going to say I think the mechanism as Ms. Triplett described where -- and I understand what you're saying. And as we sit here today, I think, yeah, that would have been a nice, easy thing for me to have is a schedule that showed what the carrying costs are. I'm pretty sure that when I get off the stand, within five or ten minutes I'll have that number. It might be in my in box, but my phone is off right now.

COMMISSIONER BALBIS: Okay.

THE WITNESS: But my understanding of the way that's being tracked is on the fuel side it's specific as to what adjustment you make and how you collect those. And then on the reg asset side there is this quarterly process where they are -- my understanding is they are presenting that collection and tracking how much is out there. So I regret that I don't have a copy of the last one we filed with me today. I'm certain that we can make that change going forward so we don't have this question again next year unanswered.

COMMISSIONER BALBIS: Well, you probably won't have it next year.

(Laughter.)

But, no, I appreciate that. And, again, Mr. Chairman, I appreciate the ability to interact here. You know, there was a lot of charges -- there were other charges associated with the settlement agreement, one being the continuation of the $3.45. And during the nuclear cost recovery proceeding there was a lot of discussion on that, and it was, there was a schedule that included the total amount, so I felt comforted at that point. And I'm looking for a similar type of exhibit or accounting mechanism to show that it's accurately being tracked.

And, Mr. Chairman, to make it even more of a free-for-all, I'd like the opportunity to ask Mr. Rehwinkel what his understanding is going forward on how this is going to be tracked to make sure that customers are protected.

MR. REHWINKEL: Well, as -- I mean, I agree with what Mr. Foster said about -- my goal today was to make sure that the accounting for the collection was right. Disposition of it I looked at as on the side of another wall, but I understand. I am fairly confident that Duke has to the penny the accounting for this, because my understanding is these dollars were supposed to be applied to the highest cost elements of the carrying costs first, which would have a beneficial impact to reduce those carrying costs going forward. I have not personally seen any of the accounting for it, but I think it's a fairly rote mechanical application that they should be able to present easily. I have not seen it though.

COMMISSIONER BALBIS: Okay. And so you anticipate either working with Duke or at this proceeding next year be able to at least discuss it and assess it?

MR. REHWINKEL: Yes. I mean, that's -- our goal is, as long as these dollars are impacting the fuel clause, is to keep asking these questions and make sure that we're just accountable for it. That's something that had not occurred to me as to kind of look at that tail end of this collection that's going through the clause.

But Duke, like they did, they put the RRSSA schedule in here at our request, and I'm sure they would, they would work with us and make sure we get that done for the next time around. We will follow through on that.

COMMISSIONER BALBIS: Okay. Thank you, Mr. Chairman. That addresses my concerns.

CHAIRMAN GRAHAM: I figure we're being asked to make a bench decision, so I try to give Commissioners as much flexibility as possible to get those answers and get a comfort level.

Any further discussion from other Commissioners? Is there a motion for a bench decision? I'm not seeing any lights come on, so it looks like there is no bench decision. So, staff, where do we go from here?

MS. BARRERA: The recommendation will be filed for the November 25th, 2014, agenda, and the Commission can make a decision at that time.

CHAIRMAN GRAHAM: Okay. Well, then --

Commissioner Balbis.

COMMISSIONER BALBIS: Mr. Chairman, now that we do have some time, and if there are no objections, if a late-filed exhibit could be filed with the Commission that has that information, I know it would alleviate even further the concerns that I have.

CHAIRMAN GRAHAM: You're lucky Mr. Moyle is not here.

(Laughter.)

COMMISSIONER BALBIS: I know. I had to look and make sure he wasn't.

MS. TRIPLETT: Mr. Chairman, if I could just clarify what information would be helpful to see in that late-filed exhibit.

COMMISSIONER BALBIS: Yes. Specifically what I would like to see is the total amount of estimated carrying charges associated with the regulatory asset that this $37 million will be writing down, if that is something that can be estimated, prepared.

MS. TRIPLETT: And I'm going to start talking about math, which I'm terrible at, but I assume that we probably need to pick a point in time, I would think. So some reasonable time around this time. I just don't know how the accounting is done. I would think perhaps the most recent month and year information available, probably September, as of September 2014?

COMMISSIONER BALBIS: That's fine.

MS. TRIPLETT: Because I think that the books should be closed --

COMMISSIONER BALBIS: That's fine.

MS. TRIPLETT: Okay.

CHAIRMAN GRAHAM: Okay. Is there anything else, staff?

MS. BARRERA: No. We will announce that the recommendation will be filed for the November 15 [sic] agenda, and at this time there are no other matters that we have.

CHAIRMAN GRAHAM: Do we have an idea of when we're going to have that late-filed exhibit?

MS. TRIPLETT: I knew you were going to ask. I can't say without talking to my folks, but I would think I could get it by the end of the week, if not -- maybe I should give myself until Monday in case folks are watching and throwing things at their computer screen. Monday close of business?

CHAIRMAN GRAHAM: Okay. So Monday close of business is 5:00.

MS. TRIPLETT: And I will try for sooner. I just --

CHAIRMAN GRAHAM: Staff, that's fine with you as far as getting the recommendation to us timely?

MS. BARRERA: Yes.

MS. HELTON: And, Mr. Chairman, we might want to give a time for all the other Intervenors and parties to object to the exhibit if they see something that's an issue to take so that we know whether to admit it into the record or not. So I guess it would be a conditional acceptance unless there is an objection that's filed by a date certain, maybe next Friday.

CHAIRMAN GRAHAM: Sounds good. So midday Friday, whatever date that is. What date is that? The 31st, Halloween.

MS. HELTON: Halloween.

MS. BARRERA: Halloween, yes.

CHAIRMAN GRAHAM: Okay. So Duke will have the late-filed exhibit in by 5:00 on Monday. And if there's any objections to that, it needs to be in by noon on the 31st. If we don't hear from you, we just assume that you're fine with it. Are we good?

MS. BARRERA: Yes, I think so.

CHAIRMAN GRAHAM: Oh, do we need an exhibit number for the late-filed exhibit?

MS. BARRERA: That will be 72.

CHAIRMAN GRAHAM: Okay. We will give it Exhibit 72.

Thank you, Commissioner Edgar.

(Late-Filed Exhibit Number 72 marked for identification.)

Okay. So now we are -- Commissioner Brown.

COMMISSIONER BROWN: Thank you. Staff, so will you be filing then a written recommendation?

MS. BARRERA: Yes.

COMMISSIONER BROWN: Okay. Memorializing --

MS. BARRERA: Yes. Memorializing what was stated today, plus --

COMMISSIONER BROWN: Conclusions.

MS. BARRERA: -- conclusions as to the late-filed exhibit, whatever conclusions staff may have on it.

COMMISSIONER BROWN: Okay. Thank you. And then we will be voting on it -- did you say December?

MS. BARRERA: November 25th.

CHAIRMAN GRAHAM: November the 25th.

COMMISSIONER BROWN: Okay. Thank you.

MR. BERNIER: Mr. Chairman, at this time we'd ask that Mr. Foster be excused.

CHAIRMAN GRAHAM: No, he can't go anywhere.

(Laughter.)

MR. BERNIER: I was worried you might say that.

CHAIRMAN GRAHAM: Mr. Foster, you are excused. Thank you very much for your testimony today.

Okay. So we are done with this docket, 140001-EI.

(Proceeding concluded at 11:04 a.m.)

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

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

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

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

DATED THIS 30th day of October, 2014.

Linda Boles

LINDA BOLES, CRR, RPR
FPSC Official Hearings Reporter
(850) 413-6734