BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20200001-EI

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

VOLUME 1
PAGES 1 through 248

PROCEEDINGS: HEARING

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

DATE: Tuesday, November 3, 2020

TIME:
Commenced: 10:20 a.m.
Concluded: 5:12 p.m.

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

REPORTED BY:
DEBRA R. KRICK
Court Reporter

PREMIER REPORTING
114 W. 5TH AVENUE
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(850) 894-0828

APPEARANCES:

MATTHEW R. BERNIER, ESQUIRE, 106 East College Avenue, Suite 800, Tallahassee, Florida 32301-7740; and DIANNE M. TRIPLETT, ESQUIRE, 299 First Avenue North, St. Petersburg, Florida 33701, appearing on behalf of Duke Energy Florida, LLC.

MARIA J. MONCADA, WADE R. LITCHFIELD, and DAVID M. LEE, ESQUIRES, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, appearing on behalf of Florida Power & Light Company.

BETH KEATING, ESQUIRE, Gunster, Yoakley & Stewart, P.A., 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301-1839, appearing on behalf of Florida Public Utilities Company.

RUSSELL A. BADDERS, ESQUIRE, One Energy Place, Pensacola, Florida 32520-0100; MARIA J. MONCADA, ESQUIRE, 700 Universe Boulevard, Juno Beach, Florida 33408-0420, appearing on behalf of Gulf Power Company.

JAMES D. BEASLEY, J. JEFFRY WAHLEN, and MALCOLM N. MEANS, ESQUIRES, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company.

APPEARANCES (CONTINUED):

J.R. KELLY, PUBLIC COUNSEL; CHARLES REHWINKEL, DEPUTY PUBLIC COUNSEL; and PATRICIA A. CHRISTENSEN, STEPHANIE A. MORSE, A. MIREILLE FALL-FRY, and THOMAS (TAD) DAVID, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 W. Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida.

JON C. MOYLE, JR., and KAREN A. PUTNAL, ESQUIRES, Moyle Law Firm, P.A., The Perkins House, 118 North Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Florida Industrial Power Users Group.

JAMES W. BREW and LAURA WYNN BAKER, ESQUIRES, Stone Mattheis Xenopoulos & Brew, PC, 1025 Thomas Jefferson Street, NW, Eighth Floor, West Tower, Washington, DC 20007, appearing on behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate - White Springs.

SUZANNE BROWNLESS, ESQUIRE, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

APPEARANCES (CONTINUED):

KEITH HETRICK, GENERAL COUNSEL; MARY ANNE HELTON, DEPUTY GENERAL COUNSEL, ESQUIRES, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Advisor to the Florida Public Service Commission.

I N D E X

WITNESSES

I N D E X
(continued)

WITNESSES

P R O C E E D I N G S

CHAIRMAN CLARK: All right. Good morning again. We are going to call the November 3rd clause docket hearing to order.

I would ask staff, if they would, please read the notice.

MS. WEISENFELD: By notice issued on October 7th, 2020, this time and place has been set for hearings in Docket Nos. 20200001-EI, 20200002-EG, 20200003-GU, 20200004-GU and 20200007-EI. The purpose of these hearings is set out more fully in the notice.

CHAIRMAN CLARK: All right. Thank you, Ms. Weisenfeld.

Let me just give kind of a quick overview of what I think -- how I think things are going to go today.

We had scheduled this for today, tomorrow and Thursday. It looks like we are going to be able to consolidate things pretty rapidly. We are not going to try to rush anything through, but my plan this morning is to get through the first -- the 02, 03, 04 and 07 dockets even prior to lunch today.

If the timing hits us right, we are going to take a lunch break at 12 o'clock. We are going to probably take about 45 minutes for lunch. Those of you that are sitting at your kitchen table, it should not be too difficult for you to grab a quick sandwich, but the rest of us have got to go out and scrape something up. So we are going to probably take about 45 minutes for lunch. Then we will come back, and if we don't get to the 01 prior to lunch, we will take it up immediately after.

My anticipation, based on the number of witnesses and what we have seen so far, is that we are going to try to finish it up today. If it doesn't look like it's going to push much past 5:00 p.m., we will stay and wrap everything up today. If it does look like it's going to go quite a bit further, then we certainly have tomorrow scheduled, and we will reconvene tomorrow morning. Maybe we can make a little bit better call on that issue somewhere around 3:30 or four o'clock this afternoon.

So with that said, we are going to take appearances with all of the dockets to begin with.

Ms. Weisenfeld.

MS. WEISENFELD: There are five dockets to address today. We suggest that all appearances be taken at once.

All parties should enter their appearances and declare the dockets that they are entering an appearance for. Several parties will make appearances, and after the parties make their appearances, staff will need to make theirs.

CHAIRMAN CLARK: All right. Thank you.

All right. So we are going to take appearances beginning with Florida Power & Light. If you would, please state the docket that you are going to be appearing in when you give your appearance, please.

FPL.

MS. MONCADA: Good morning, Mr. Chairman. Can you hear me?

CHAIRMAN CLARK: Yes, we can hear you.

MS. MONCADA: Wonderful.

Maria Moncada on behalf of Florida Power & Light Company in the 01, 02 and 07 dockets. In each of those dockets, I would like to also enter an appearance for our general counsel, Wade Litchfield. In the 01 and 07 dockets, I will also enter an appearance for David Lee, and in the 02 docket, for Joel Baker.

Mr. Chairman, I am also here today on behalf of Gulf Power Company in the 01 and the 07 dockets.

And in those two dockets, I would like to also enter an appearance for Russell Badders.

Thank you.

CHAIRMAN CLARK: All right. Any other -- any other appearances for Gulf Power?

MR. GRIFFIN: Yes, Mr. Chairman. Thank you. Good morning, Commissioners.

This is Steven Griffin with the Beggs & Lane law firm in Pensacola. I will be entering an appearance for Gulf Power Company in the 02 docket, and would also like to enter an appearance for Russell Badders with Gulf Power Company in the 02 docket as well.

Thank you.

CHAIRMAN CLARK: All right. Thank you very much.

Duke Energy, Mr. Bernier.

MR. BERNIER: Good morning, Mr. Chairman, Commissioners. Matt Bernier from Duke Energy. I will be appearing in the 01, 02 and 07 dockets. I would also like to enter an appearance for Dianne Triplett in the same dockets.

Thank you.

CHAIRMAN CLARK: Thank you very much.

TECO.

MR. MEANS: Good morning, Mr. Chairman, Commissioners. This is Malcolm Means with the Ausley McMullen law firm in Tallahassee. I would also like to enter appearances for Jim Beasley and Jeff Wahlen with the Ausley McMullen law firm. We are appearing on behalf of Tampa Electric in the 02, 07 and 01 dockets.

Thank you.

CHAIRMAN CLARK: Thank you very much.

Florida Public Utilities, Ms. Keating.

MS. KEATING: Good morning, Mr. Chairman, Commissioners. Beth Keating with the Gunster Law Firm appearing today on behalf of FPUC in the 01, 02, 03 and 04 dockets. I will also be making an appearance for Chesapeake and Sebring in the 04 docket, and I will also be appearing for Florida City Gas in the 03 and 04 dockets. And in those dockets, I would like to also enter appearance for Greg Munson with the Gunster Law Firm, as well as Chris Wright with FPL.

CHAIRMAN CLARK: All right. Thank you very much.

That takes care of Florida City Gas and Sebring Gas. Anybody else under those two?

All right moving to Peoples Gas.

MR. BROWN: Thank you, Mr. Chairman, Andy Brown of the law firm of Macfarlane Ferguson & McMullen. I am appearing on behalf of Peoples Gas in the 03 and 04 dockets.

CHAIRMAN CLARK: All right. St. Joe Natural Gas Company. They were requested to be excused? Okay.

MS. WEISENFELD: They should be on the line. They should be on the line. St. Joe should be on the line, Mr. Chairman.

CHAIRMAN CLARK: Okay. Is there anyone from St. Joe? Anyone from St. Joe? Stuart Shoaf?

All right. Move right along to the Office of Public Counsel.

MS. FALL-FRY: Good morning. A. Mireille Fall-Fry. I will be appearing for the Office of Public Counsel in the 02, 03, 04 and 07 dockets, and also would like to enter an appearance for Charles Rehwinkel and Stephanie Morse in the 01 docket, and J.R. Kelly in all of the dockets.

CHAIRMAN CLARK: All right. Thank you, Ms. Fall-Fry.

FIPUG.

MS. PUTNAL: Good morning, Mr. Chairman, Commissioners. Karen Putnal with the Moyle Law

Firm appearing on behalf of Florida Industrial Power Users Group in the 01, 02 and 07 dockets. And I would also like to enter an appearance for Jon Moyle in all three.

CHAIRMAN CLARK: All right. Thank you, Ms. Putnal.

PCS Phosphate.

MR. BREW: Good morning, Chairman and Commissioners. For White Springs Agricultural Chemicals, PCS Phosphate, with the law firm of Stone Mattheis Xenopoulos & Brew, in the 01, 02 and 07 dockets, I am James Brew, and I would like to note the appearance of Laura Baker and as well.

CHAIRMAN CLARK: All right. Great. Thank you very much, Mr. Brew.

Commission staff.

MS. WEISENFELD: Ashley Weisenfeld in the 02 docket. I would also like to enter appearances for Kurt Schrader in the 03, Gabriella Passidomo in the 04, Charles Murphy in the 07 and Suzanne Brownless in the 01.

MS. HELTON: And finally, Mr. Chairman, Mary Anne Helton is here as your Advisor today, as well as for the other Commissioners, along with your General Counsel, Keith Hetrick.

CHAIRMAN CLARK: Thank you, Ms. Helton.

Okay, let's move to preliminary matters, Ms. Weisenfeld.

MS. WEISENFELD: State buildings are currently closed to the public, and other restrictions on gatherings remain in place due to COVID-19. Accordingly, this hearing is being conducted remotely with the parties participating by communications media technology.

Members of the public who want to observe or listen to this hearing may do so by accessing the live video broadcast which is available from the Commission website. Upon completion of the hearing, the archived video will also be available.

Each person participating today needs to keep their phone or device muted when they are not speaking, and only unmute when they are called upon to speak. If they do not keep their phone muted, or put their phone on hold, they may be disconnected from the proceeding and will need to call back in.

Also, telephonic participants should speak directly into their phone and not use their speaker function.

CHAIRMAN CLARK: All right. Thank you, Ms.

Weisenfeld.

All right. The order of the dockets we are going to take up today, we are going to begin with the 02 docket, the 03, the 04 and the 07, and then we will conclude the day with the 01 docket.

(Whereupon, other matters were held before the Commission, and Docket No. 20200001-EI proceedings are as follows:)

CHAIRMAN CLARK: All right. We are going to open the 01 docket. I assume all the parties are on the line and, staff, are there preliminary matters?

MS. BROWNLESS: Yes, sir.

There are proposed Type 2 stipulations for all of FPUC, Gulf and TECO issues listed in the Prehearing Order, Section X, on pages 37 through 56. For FPUC Issue 3A, stated on page 11 of the Prehearing Order, there is no corresponding stipulated stated since it was inadvertently admitted. The parties have agreed to the following:

Issue 3A, should the Commission approve FPUC's revised fuel and purchase power cost recovery factors filed in accordance with the stipulation and settlement approved in Docket No.

201980156-EI -- actually, it's probably 20190156-EI -- which reflect the flow-through of interim rate overrecovery calculated based on nine months actual and one month estimated revenue? The stipulation is yes.

There are proposed Type 2 stipulations for the following Florida Power & Light issues: 2A, 2B, 2C, 2D, 2E, 2H, 6, 7, 11, 16, 17, 19, 21, 24A, 24B, 27, 28, 29, 30, 31, 32, 33, 34, 35 and 36. These are contained in the Prehearing Order, Section X, pages 37 through 56 as well.

FPL's Issues 2F, 2G, 8, 9, 10, 18, 20 and 22 are outstanding.

There are no proposed Type 2 stipulations for any of DEF's issues: Issues 1A, 6 through 11, 16 through 22, 23A through 23D, 27 through 33 and 34 through 36. These are contained in the Prehearing Order, Section VIII, on pages seven through 32.

The issues for which there are type -- there are proposed Type 2 stipulations can be voted on today.

Finally, yesterday, DEF filed an appeal and motion for stay of the Commission's order adopting Judge Stevenson's Recommended Order regarding Bartow Unit 4 replacement power costs. This motion will be dealt with at the Commission's December 1st agenda conference.

And that's all, sir.

CHAIRMAN CLARK: Thank you very much, Ms. Brownless.

Okay, let's address prefiled testimony.

MS. BROWNLESS: Thank you.

It is our understanding that the following witnesses have been excused, and the prefiled testimonies of McClay, Lewter, Deaton, Yupp, Rote, Fuentes, Anderson, Young, Cutshaw, Hume, Sizemore, Cain, Smith, Heisey and Dobiac have been stipulated to by the parties.

We would ask that the prefiled testimony of these witnesses be moved into the record at this time.

CHAIRMAN CLARK: Without objection, the prefiled testimony is moved into the record.

(Whereupon, prefiled direct testimony of James McClay was inserted.)

DUKE ENERGY FLORIDA
DOCKET NO. 20200001-EI

Fuel and Capacity Cost Recovery
Final True-Up for the Period
January through December 2019

DIRECT TESTIMONY OF
JAMES MCCLAY

April 3, 2020

Q. Please state your name and business address.

A. My name is James McClay. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

A. I employed by Duke Energy Carolinas ("DEC"), an affiliate company of Duke Energy Florida, LLC ("DEF", "Petitioner" or "Company") as the Director of Trading. I manage the Southeast power trading, Midwest financial activities, oil procurement and natural gas group procurement, scheduling and hedging activities in the Trading and Dispatch Section of the Fuels and Systems Optimization Department for the Duke Energy regulated generation fleet. This group is responsible for the hourly trading, financial hedging activities, oil procurement and natural gas procurement and scheduling needed to support the gas generation needs for Duke Energy Indiana, Duke Energy

Kentucky, Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida.

Q. Have you testified before the Commission in previous fuel clause proceedings?

A. Yes.

Q. Please briefly describe your work experience.

A. I received a Bachelor Degree in Business Administration majoring in Finance from St. Bonaventure University. I joined Progress Energy in 1998 as the Manager of Power Trading and held that position through early 2003 and then became the Director of Power Trading and Portfolio Management for Progress Energy Ventures through February 2007. From March 2007 through late 2008, I was the Director of Power Trading for Arclight Energy Marketing. From March 2009 through present I've been either the Director of Trading, Director of Natural Gas or the Manager of Gas and Oil Trading with Progress Energy and Duke Energy. Prior to my tenure with Duke Energy, I spent approximately 13 years in Capital Markets as a U.S. Government fixed income securities trader with various banks, and primary broker/ dealers.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the August through December 2019 hedging true-up data and summarize the results of DEF's hedging activity for calendar year 2019 as required by Commission Order No. PSC-02-1484-

FOF-EI and further clarified by Commission Orders No. PSC-08-0667-PPA-EI issued in October 2008, and No. PSC-09-0255-PAA-EI issued in April 2009.

Q. Have you prepared exhibits to your testimony?

A. No. To clarify, DEF does not have any hedges in place past March 2019 - therefore there are no results to report for August through December of 2019.

Q. What are the objectives of DEF's hedging strategy?

A. The objectives of DEF's hedging program are to reduce fuel price volatility risk and provide greater cost certainty for DEF's customers.

Q. What hedging activities did DEF undertake for 2019 and what were the results?

A. As discussed below, DEF did not execute any hedges during 2019. Prior hedging activities resulted in a net hedge savings for 2019 of approximately $100,700.

Q. Did DEF execute its hedging activities consistent with its approved Risk Management Plan?

A. As part of the Joint Stipulation and Agreement for Interim Resolution of Hedging Issues filed on October 24, 2016 in Docket No. 20160001-EI, DEF ceased hedging activities. Subsequently, DEF agreed to a hedging moratorium during the term of the 2017 Second Revised and Restated

Stipulation and Settlement Agreement, approved by the Commission in Docket No. 20170183-EI. Notwithstanding the suspension of prospective hedging activities, DEF had hedging transactions entered into under previously approved risk management plans that settled in 2019.

As outlined in those earlier Commission-approved plans, actual hedge percentages for any monthly period, rolling twelve month time period or calendar annual period can come in higher or lower than the hedge percentage targets as a result of actual versus forecasted fuel burns.

Q. Did DEF hedging activities meet the stated objective and are the activities consistent with the Commission's Orders for hedging?

A. Yes. DEF's hedging activity met the stated objective of DEF's hedging program to reduce price risk and provide greater cost certainty for DEF's customers. The hedging activities are consistent with Commission Orders No. PSC-02-1484-FOF-EI, No. PSC-08-0667-PPA-EI, and No. PSC-09-0255-PAA-EI. DEF's hedging activities are conducted in an environment of strong internal controls and executed in a structured manner. DEF's hedging activities do not attempt to outguess the market and may or may not result in net fuel cost savings, but have achieved the objectives of reduced fuel price volatility.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Mary Ingle Lewter was inserted.)

DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20200001-EI

GPIF Schedules for
January through December 2019

DIRECT TESTIMONY OF
MARY INGLE LEWTER

March 16, 2020

Q. Please state your name and business address.

A. My name is M. Ingle Lewter. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Indiana, LLC ("DEI") as Manager of Fuels and Fleet Analytics for Fuels and Systems Optimization.

Q. Describe your responsibilities as Manager of Fuels and Fleet Analytics.

A. As Manager of Fuels and Fleet Analytics for Fuels and Systems Optimization, I oversee the analysis and modeling of energy portfolios for Duke Energy Corporation's regulated utility subsidiaries, including Duke Energy Florida, LLC ("DEF" or "Company"), as well as Duke Energy Carolinas ("DEC"), Duke Energy Progress, LLC ("DEP"), DEI, and Duke

Energy Kentucky, Inc ("DEK"). My responsibilities include oversight of planning and coordination associated with economic system operations, including production cost modeling, outage coordination, dispatch pricing, fuel burn forecasting, position analysis, and commodities analytics.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science in Statistics from North Carolina State University in 1995. I have worked with Progress Energy (Carolina Power & Light) and Duke Energy combined since graduating from North Carolina State University in 1995. I started with Carolina Power & Light (CP&L) in the customer service area and then moved into payroll services in 1997. In 1999, I joined the Bulk Power Marketing Department as a Business Analyst and was responsible for data analysis, including load forecast metrics, external market tracking and unit commitment modeling. In 2000, I took the role of Power Scheduler and was responsible for scheduling, confirming and tagging all short-term physical power transactions. In 2005, I was promoted to Portfolio Analyst in the Portfolio Management group. In this role, I was responsible for the short-term seven-day unit commitment plan for Progress Energy Florida, which included load forecast development, generation scheduling, unit commitment and the fuel burn forecast. In 2008, I moved from the short-term seven-day unit commitment responsibilities to the mid-term forecasting role and was promoted to Senior Portfolio Analyst. In 2012, I was promoted to Lead Fuels & Fleet Analyst when Progress Energy merged with Duke Energy. In these roles, I was responsible for the 5-year mid-term forecast for Duke Energy Carolinas and Duke Energy Midwest utilities, which are utilized for fuel planning, regulatory fuel filings, and budget development. In December 2019, I became the Manager of Fuels & Fleet Analytics, which is responsible for the mid-term forecast for all Duke Energy Jurisdictions (DEC, DEP, DEI, DEK, and DEF).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of DEF's Generating Performance Incentive Factor ("GPIF") reward/(penalty) amount for the period of January through December 2019. This calculation was based on a comparison of the actual performance of DEF's Seven (7) GPIF generating units for this period against the approved targets set for these units prior to the actual performance period.

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

A. Yes, I am sponsoring Exhibit No. _______ (MIL-1T), which consists of the schedules required by the GPIF Implementation Manual to support the development of the incentive amount. This 24-page exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

Q. What GPIF incentive amount has been calculated for this period?

A. DEF's calculated GPIF incentive amount is a reward of $4,407,712. This amount was developed in a manner consistent with the GPIF Implementation Manual. Page 2 of my exhibit shows the system GPIF points and the corresponding reward/(penalty). The summary of weighted incentive points earned by each individual unit can be found on page 4 of my exhibit.

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

A. The calculation of incentive points was made by comparing the adjusted actual performance data for equivalent availability and heat rate to the target performance indicators for each unit. This comparison is shown on each unit's Generating Performance Incentive Points Table found on pages 9 through 15 of my exhibit.

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

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

In addition, the Bartow combined cycle (“CC”) unit had data excluded during the period in which its steam turbine was in a planned outage. The Bartow CC unit has the capability to be operated in simple cycle mode while the steam turbine is in an outage. When operating in simple cycle mode, the unit’s heat rate will deviate significantly from its normal range. DEF’s heat rate target setting process for the Bartow CC unit excludes historical data from periods when the unit operated in simple cycle mode. From late September until early December 2019 the steam turbine was in a planned outage; during this period the Bartow CC unit was operated in simple cycle mode when the combustion turbines ("CT") were available. To be consistent with the target setting process, simple cycle mode heat rate data was excluded from actuals for the purposes of calculating the heat rate for the Bartow CC in year 2019 during those times when the unit was being operated in simple cycle mode as the result of a planned outage.

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

A. Yes. Page 23 of my exhibit summarizes the planned outages experienced by DEF’s GPIF units during the period. Page 24 presents an as-worked schedule for each individual planned outage.

Q. Does this conclude your testimony?

A. Yes.

IN RE: PETITION ON BEHALF OF DUKE ENERGY FLORIDA
FOR
FUEL AND CAPACITY COST RECOVERY
FINAL TRUE-UP FOR THE PERIOD
JANUARY THROUGH DECEMBER 2019

FPSC DOCKET NO. 20200001-EI

GPIF TARGETS AND RANGES FOR
JANUARY THROUGH DECEMBER 2021

DIRECT TESTIMONY OF
MARY INGLE LEWTER

September 3, 2020

Q. Please state your name and business address.

A. My name is M. Ingle Lewter. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Indiana, LLC (“DEI”) as Manager of Fuels and Fleet Analytics for Fuels and Systems Optimization. DEI and Duke Energy Florida, LLC (“DEF” or “Company”) are both wholly-owned subsidiaries of Duke Energy Corporation (“Duke Energy”).

Q. What are your responsibilities in that position?

A. As Manager of Fuels and Fleet Analytics for Fuels and Systems Optimization, I oversee the analysis and modeling of energy portfolios for Duke Energy Corporation’s regulated utility subsidiaries, including Duke Energy Florida, LLC (“DEF” or “Company”), as well as Duke Energy Carolinas ("DEC"), Duke Energy Progress, LLC ("DEP"), DEI, and Duke

Energy Kentucky, Inc ("DEK"). My responsibilities include oversight of planning and coordination associated with economic system operations, including production cost modeling, outage coordination, dispatch pricing, fuel burn forecasting, position analysis, and commodities analytics.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science in Statistics from North Carolina State University in 1995. I have worked with Progress Energy (Carolina Power & Light) and Duke Energy combined since graduating from North Carolina State University in 1995. I started with Carolina Power & Light (CP&L) in the customer service area and then moved into payroll services in 1997. In 1999, I joined the Bulk Power Marketing Department as a Business Analyst and was responsible for data analysis, including load forecast metrics, external market tracking and unit commitment modeling. In 2000, I took the role of Power Scheduler and was responsible for scheduling, confirming and tagging all short-term physical power transactions. In 2005, I was promoted to Portfolio Analyst in the Portfolio Management group. In this role, I was responsible for the short-term seven-day unit commitment plan for Progress Energy Florida, which included load forecast development, generation scheduling, unit commitment and the fuel burn forecast. In 2008, I moved from the short-term seven-day unit commitment responsibilities to the mid-term forecasting role and was promoted to Senior Portfolio Analyst. In 2012, I was promoted to Lead Fuels & Fleet Analyst when Progress Energy merged with Duke Energy. In these roles, I was responsible for the 5-year mid-term forecast for Duke Energy Carolinas and Duke Energy Midwest utilities, which are utilized for fuel planning, regulatory fuel filings, and budget development. In December 2019, I became the Manager of Fuels & Fleet Analytics, which is responsible for the mid-term forecast for all Duke Energy Jurisdictions (DEC, DEP, DEI, DEK, and DEF).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a recap of actual reward / penalty for the period of January through December 2019, and outline the development of the Company's Generating Performance Incentive Factor ("GPIF") targets and ranges for the period January through December 2021. These GPIF targets and ranges have been developed from individual unit equivalent availability, average net operating heat rate targets, and improvement/degradation ranges for each of the Company's GPIF generating units, in accordance with the Commission's GPIF Implementation Manual.

Q. What GPIF incentive amount was calculated and reported in your March 16, 2020 testimony for the period January through December 2019?

A. DEF's calculated GPIF incentive amount for this period was a reward of $4,407,712. Please refer to my testimony filed March 16, 2020 for the details of how this incentive amount was calculated.

Q. Have there been any adjustments to the incentive amount filed in March?

A. No.

Q. Do you have an exhibit to your testimony?

A. Yes. I am sponsoring Exhibit No. _____ (MIL-1P), which consists of the GPIF standard form schedules prescribed in the GPIF Implementation Manual and supporting data, including outage rates, net operating heat rates, and computer analyses and graphs for each of the individual GPIF units. This exhibit is attached to my prepared testimony and includes as its first page an index to the contents of the exhibit.

Q. Which of the Company's generating units have you included in the GPIF program for the upcoming projection period?

A. For the 2021 projection period, the GPIF program includes the following units: Bartow Unit 4, Crystal River Unit 4, Crystal River Unit 5, and Hines Units 1 through 4. Combined, these units account for 85% of the estimated total system net generation for the period, excluding Citrus CC units. Citrus CC Units 1 and 2 were not included for the upcoming projection period since they do not meet the inclusion of performance history to use in setting targets and ranges for these units.

Q. Have you determined the equivalent availability targets and improvement/degradation ranges for the Company's GPIF units?

A. Yes. This information is included in the GPIF Target and Range Summary on page 4 of my Exhibit No. ___ (MIL-1P).

Q. How were the equivalent availability targets developed?

A. The equivalent availability targets were developed using the methodology established for the Company's GPIF units, as set forth in Section 4 of the GPIF Implementation Manual. This includes the formulation of graphs based on each unit's historic performance data for the four individual unplanned outage rates (i.e., forced, partial forced, maintenance, and partial maintenance outage rates), which in combination constitute the unit's equivalent unplanned outage rate ("EUOR"). From operational data and these graphs, the individual target rates are determined through a review of three years of monthly data points. The unit's four target rates are then used to calculate its unplanned outage hours for the projection period. When the unit's projected planned outage hours are taken into account, the hours calculated from these individual unplanned outage rates can then be converted into an overall equivalent unplanned outage factor ("EUOF"). Because factors are additive (unlike rates), the EUOF and planned outage factor ("POF") when added to the equivalent availability factor ("EAF") will always equal 100%. For example, an EUOF of 15% and POF of 10% results in an EAF of 75%. The supporting tables and graphs for the target and range rates are contained in pages 41-76 of my exhibit in the section entitled "Unplanned Outage Rate Tables and Graphs."

Q. Please describe the methodology utilized to develop the improvement/degradation ranges for each GPIF unit's availability targets?

A. The methodology described in the GPIF Implementation Manual was used. Ranges were first established for each of the four unplanned outage rates associated with each unit. From an analysis of the unplanned outage graphs, units with small historical variations in outage rates were assigned narrow ranges and units with large variations were assigned wider ranges. These individual ranges, expressed in term of rates, were then converted into a single unit availability range, expressed in terms of a factor, using the same procedure described above for converting the availability targets from rates to factors.

Q. Were adjustments made to historical unit availability to account for significant anomalies in historical performance?

A. No.

Q. Have you determined the net operating heat rate targets and ranges for the Company's GPIF units?

A. Yes. This information is included in the Target and Range Summary on page 4 of my Exhibit No. ___ (MIL-1P).

Q. How were these heat rate targets and ranges developed?

A. The development of the heat rate targets and ranges for the upcoming period utilized historical data from the past three years, as described in the GPIF Implementation Manual. A "least squares" procedure was used to curve-fit the heat rate data to a linear relationship with Net Operating Factor (NOF), and ranges at a 90% confidence level were also established assuming a normal distribution. The analyses and data plots used to develop the heat rate targets and ranges for each of the GPIF units are contained in pages 26-40 of my exhibit in the section entitled "Average Net Operating Heat Rate Curves."

Q. How were the GPIF incentive points developed for the unit availability and heat rate ranges?

A. GPIF incentive points for availability and heat rate were developed by evenly spreading the positive and negative point values from the target to the maximum and minimum values in the case of availability, and from the neutral band to the maximum and minimum values in the case of heat rate. The fuel savings (loss) dollars were evenly spread over the range in the same manner as described for incentive points. The maximum savings (loss) dollars are the same as those used in the calculation of the weighting factors.

Q. How were the GPIF weighting factors determined?

A. To determine the weighting factors for availability, a series of simulations was made using a production costing model in which each unit's maximum equivalent availability was substituted for the target value to obtain a new system fuel cost. The differences in fuel costs between these cases and the target case determine the contribution of each unit's availability to fuel savings. The heat rate contribution of each unit to fuel savings was determined by multiplying the BTU savings between the minimum and target heat rates (at constant generation) by the average cost per BTU for that unit. Weighting factors were then calculated by dividing each individual unit's fuel savings by total system fuel savings.

Q. What was the basis for determining the estimated maximum incentive amount?

A. The determination of the maximum reward or penalty was based upon monthly common equity projections obtained from a detailed financial simulation performed by the Company's Corporate Model.

Q. What is the Company's estimated maximum incentive amount for 2021?

A. The estimated maximum incentive for the Company is $12,512,937. The calculation of the estimated maximum incentive is shown on page 3 of my Exhibit No. ___ (MIL-1P).

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Renae B. Deaton was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20200001-EI

MARCH 2, 2020

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

A. My name is Renae B. Deaton. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or "the Company") as the Director, Clause Recovery and Wholesale Rates, in the Regulatory & State Governmental Affairs Department.

Q. Please state your education and business experience.

A. I hold a Bachelor of Science in Business Administration and a Master of Business Administration from Charleston Southern University. Since joining FPL in 1998, I have held various positions in the rates and regulatory areas. Prior to my current position, I held the positions of Senior Manager of Cost of Service and Load Research and Senior Manager of Rate Design in the Rates and Tariffs Department. I am a member of the Edison Electric Institute ("EEI") Rates and Regulatory Affairs Committee, and I have completed the EEI Advanced Rate Design Course. I have been a guest speaker at Public Utility Research Center/World Bank International Training Programs on Utility Regulation and Strategy. In 2016, I assumed my current position, where my duties include providing direction as to appropriateness of inclusion of costs through a cost recovery clause and the overall preparation and filing of all cost recovery clause documents including testimony and discovery. As part of the various roles I have held with the Company, I have testified before this Commission in base rate and clause recovery proceedings.

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

A. The purpose of my testimony is to present the schedules necessary to support the actual Fuel Cost Recovery ("FCR") Clause and Capacity Cost Recovery ("CCR") Clause net true-up amounts for the period January 2019 through December 2019.

The 2019 net true-up for the FCR Clause is an under-recovery, including interest, of $51,531,817. FPL is requesting Commission approval to include this 2019 FCR Clause true-up under-recovery in the calculation of the FCR factors for the period January 2021 through December 2021.

The 2019 net true-up for the CCR Clause is an over-recovery, including interest, of $5,141,967. FPL is requesting Commission approval to include this 2019 CCR Clause true-up over-recovery in the calculation of the CCR factors for the period January 2021 through December 2021.

Finally, FPL is requesting Commission approval to include $9,149,588 in the calculation of the FCR factors for the period January 2021 through December 2021, which represents FPL's share of the 2019 Incentive Mechanism gains described in the testimony of FPL witness Yupp and presented on page 1 of Exhibit GJY-1.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits in this proceeding?

A. Yes, I have. Exhibit RBD-1 contains the FCR-related schedules and Exhibit RBD-2 contains the CCR-related schedules. In addition, FCR Schedules A1 through A12 for the January 2019 through December 2019 period have been filed monthly with the Commission and served on all parties of record in this docket. Those schedules are incorporated herein by reference.

Q. What is the source of the data you present?

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

FUEL COST RECOVERY CLAUSE

Q. Please explain the calculation of the 2019 FCR net true-up amount.

A. Exhibit RBD-1, page 1, titled "Calculation of Net True-Up," shows the calculation of the FCR net true-up for the period January 2019 through December 2019, an under-recovery of $51,531,817.

The summary of the FCR net true-up amount shows the actual end-of-period true-up over-recovery for the period January 2019 through December 2019 of

$77,204,120 on line 1. The actual/estimated true-up over-recovery for the same period of $128,735,937 is shown on line 2. Line 1 less line 2 results in the net final true-up under-recovery for the period January 2019 through December 2019 of $51,531,817 shown on line 3.

The calculation of the FCR true-up amount for the period follows the procedures established by this Commission as set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision."

Q. Have you provided a schedule showing the calculation of the 2019 FCR actual true-up by month?

A. Yes. Exhibit RBD-1, page 2, titled "Calculation of Final True-Up Amount," shows the calculation of the FCR actual true-up by month for January 2019 through December 2019.

Q. Have you provided a schedule showing the variances between actual and actual/estimated FCR costs and applicable revenues for 2019?

A. Yes. Exhibit RBD-1, page 3, (sum of lines 39 and 40) compares the actual end-of-period true-up over-recovery of $77,204,120 (column 4) to the actual/estimated end-of-period true-up over-recovery of $128,735,937 (column 5) resulting in a net under-recovery of $51,531,817 (column 6). Exhibit RBD-1, page 3 shows that the variance consists of an increase in jurisdictional fuel costs of $101.0 million (line 38) partially offset by an increase in revenues of $49.6 million (line 29).

Q. Please summarize the variance schedule on page 3 of Exhibit RBD-1.

A. FPL previously projected jurisdictional total fuel costs and net power transactions to be $2.58 billion for 2019 (Exhibit RBD-1, page 3, line 38, column 5). The actual jurisdictional total fuel costs and net power transactions for that period is $2.69 billion (Exhibit RBD-1, page 3, line 38, column 4). Jurisdictional total fuel costs and net power transactions are $101.0 million, or 3.9% higher than previously projected (Exhibit RBD-1, page 3, line 38, column 6) and jurisdictional fuel revenues net of revenue taxes for 2019 are $49.6 million, or 1.7% higher than previously projected (Exhibit RBD-1, page 3, line 29, column 6).

Q. Please explain the variances in jurisdictional total fuel costs and net power transactions.

A. Below are the primary reasons for the $101.0 million variance.

<u>Fuel Cost of System Net Generation: $125.8 million increase (Exhibit RBD-1, page 3, line 1, column 6)</u>

The table below provides the detail of this variance.

FUEL VARIANCE	2019 FINAL TRUE-UP	2019 ACTUAL/ ESTIMATED	DIFFERENCE
<u>Heavy Oil</u>			
Total Dollar	$13,793,931	$12,853,413	940,518
Units (MMBTU)	1,196,123	1,115,626	80,498
$ per Units	11.5322	11.5213	0.01
Variance Due to Consumption			928,316
Variance Due to Cost			12,202
Total Variance			940,518
<u>Light Oil</u>			
Total Dollar	$20,107,057	$11,992,199	8,114,858
Units (MMBTU)	1,182,072	706,510	475,563
$ per Units	17.0100	16.9739	0.04

FUEL VARIANCE	2019 FINAL TRUE-UP	2019 ACTUAL/ ESTIMATED	DIFFERENCE
Variance Due to Consumption			8,089,322
Variance Due to Cost			25,536
Total Variance			8,114,858
Coal			
Total Dollar	$74,236,959	$69,189,030	5,047,929
Units (MMBTU)	28,631,872	27,200,891	1,430,981
$ per Units	2.5928	2.5436	0.05
Variance Due to Consumption			3,710,260
Variance Due to Cost			1,337,670
Total Variance			5,047,929
Gas			
Total Dollar	$2,600,448,500	$2,493,615,287	106,833,213
Units (MMBTU)	665,984,354	637,898,271	28,086,083
$ per Units	3.9047	3.9091	(0.00)
Variance Due to Consumption			109,666,859
Variance Due to Cost			(2,833,646)
Total Variance			106,833,213
Nuclear			
Total Dollar	$159,950,571	$155,046,037	4,904,534
Units (MMBTU)	303,397,508	298,655,844	4,741,664
$ per Units	0.5272	0.5191	0.01
Variance Due to Consumption			2,499,796
Variance Due to Cost			2,404,738
Total Variance			4,904,534
Total			
Variance Due to Consumption			124,894,552
Variance Due to Cost			946,500
Total Variance			125,841,052

Variable Power Plant O&M Avoided due to Economy Purchases: $0.05 million decrease (Exhibit RBD-1, page 3, line 13, column 6)

The variance for variable power plant O&M avoided due to economy purchases is attributable to lower than projected economy power purchases.

<u>Variable Power Plant O&M Attributable to Off-System Sales: $0.1 million increase (Exhibit RBD-1, page 3, line 12, column 6)</u>

The variance for variable power plant O&M attributable to off-system sales is attributable to higher than projected economy power sales.

<u>Energy Cost of Economy Purchases: $1.4 million increase (Exhibit RBD-1, page 3, line 8, column 6)</u>

The variance for the Energy Cost of Economy Purchases is attributable to higher than projected costs for economy power. The average cost of economy power purchases was $7.95/MWh higher than projected, resulting in a cost increase of $4.4 million. This increase was partially offset by lower than projected economy purchases. FPL purchased 76,939 MWh less of economy power, resulting in a volume decrease of $3.0 million. The combination of lower economy power purchases coupled with higher costs for economy power purchases resulted in a net variance of $1.4 million.

<u>Fuel Cost of Power Sold: $2.6 million increase (Exhibit RBD-1, page 3, line 4, column 6)</u>

The variance for the Fuel Cost of Power Sold is primarily attributable to higher than projected economy power sales. FPL sold 191,325 MWh more of economy power, resulting in a volume increase of $3.8 million. The average unit fuel cost on economy power sales was $0.48/MWh lower than projected, resulting in a cost decrease of $1.3 million. The combination of higher economy power sales and lower fuel costs attributable to economy power sales resulted in a net variance for economy power sales of $2.5 million. The remaining variance of $0.1 million was primarily attributable to higher than projected fuel costs on St. Lucie Plant Reliability Exchange sales.

<u>Gains from Off-System Sales: $2.4 million increase (Exhibit RBD-1, page 3, line 5, column 6)</u>

The variance for Gains from Off-System Sales is attributable to higher than projected economy sales and higher than projected margins on economy power sales. FPL sold 191,325 MWh more of economy power, resulting in a volume increase of $1.7 million. Margins on economy power sales averaged $0.26/MWh higher than projected, resulting increased gains of $0.7 million. The combination of higher economy power sales and higher margins on economy power sales resulted in a total variance for Gains from Off-System Sales of $2.4 million.

<u>Fuel Cost of Stratified Sales: $6.4 million increase (Exhibit RBD-1, page 3, line 2, column 6)</u>

The variance for the fuel cost of stratified sales is primarily attributable to higher than projected MWh sales to Seminole.

<u>Fuel Cost of Purchased Power: $0.8 million increase (Exhibit RBD-1, page 3, line 6, column 6)</u>

The variance for the Fuel Cost of Purchased Power is primarily attributable to higher than projected firm purchases and lower than projected costs associated with these firm purchases. In total, FPL purchased 130,894 MWh more than projected, resulting in a volume increase of $2.7 million. The unit cost of these firm purchases was $1.15/MWh lower than projected, resulting in a cost decrease of $1.9 million. The combination of higher firm purchases and lower costs for firm purchases resulted in a net variance of $0.8 million.

<u>Energy Payments to Qualifying Facilities: $0.1 million increase (Exhibit RBD-1, page 3, line 7, column 6)</u>

The variance for Energy Payments to Qualifying Facilities is attributable to higher than projected purchases and lower than projected costs from Qualifying Facilities. In total, FPL purchased 23,134 MWh more than projected, resulting in a volume increase of $0.4 million. The average unit fuel cost for these purchases was $1.02/MWh lower than projected, resulting in a cost decrease of $0.3 million. The combination of higher purchases and lower fuel costs for Qualifying Facilities resulted in a net variance of $0.1 million.

Q. What is the variance in retail (jurisdictional) FCR revenues?

A. As shown on Exhibit RBD-1, page 3, line 29, actual 2019 jurisdictional FCR revenues, net of revenue taxes, are approximately $49.6 million higher than the actual/estimated projection. This is primarily due to jurisdictional sales that are 1,591,574 MWh higher than the actual/estimated projection.

Q. FPL witness Yupp calculates in his testimony that FPL is entitled to retain $9,149,588 as its 60% share of 2019 Incentive Mechanism gains over the $40 million threshold. When is FPL requesting to recover its share of the gains,

and how will this be reflected in the FCR schedules?

A. FPL is requesting recovery of its share of the 2019 Incentive Mechanism gains through the 2021 FCR factors, consistent with how gains have been recovered in prior years. FPL will include the approved jurisdictionalized Incentive Mechanism gains amount in the calculation of the 2021 FCR factors and will reflect recovery of one-twelfth of the approved amount, net of revenue taxes, in each month's Schedule A2 for the period January 2021 through December 2021 as a reduction to jurisdictional fuel revenues applicable to each period.

CAPACITY COST RECOVERY CLAUSE

Q. Please explain the calculation of the 2019 CCR net true-up amount.

A. Exhibit RBD-2, page 1, titled "Final True-Up Summary" shows the calculation of the CCR net true-up for the period January 2019 through December 2019, an over-recovery of $5,141,967, which FPL is requesting to be included in the calculation of the CCR factors for the January 2021 through December 2021 period.

The actual end-of-period over-recovery for the period January 2019 through December 2019 of $14,144,582 shown on line 1 less the actual/estimated end-of-period over-recovery for the same period of $9,002,615 shown on line 2 that was approved by the Commission in Order No. PSC-2019-0484-FOF-EI, results in the net true-up over-recovery for the period January 2019 through December 2019 of $5,141,967 shown on line 3.

Q. Have you provided a schedule showing the calculation of the 2019 CCR actual true-up by month?

A. Yes. Exhibit RBD-2, pages 2 through 4, titled "Calculation of Final True-Up" shows the calculation of the CCR end-of-period true-up for the period January 2019 through December 2019 by month.

Q. Is this true-up calculation consistent with the true-up methodology used for the FCR Clause?

A. Yes, it is. The calculation of the true-up amount follows the procedures established by this Commission set forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision" for the FCR Clause.

Q. Have you provided a schedule showing the variances between actual and actual/estimated capacity costs and applicable revenues for 2019?

A. Yes. Exhibit RBD-2, pages 5 and 6, titled "Calculation of Final True-Up Variances," shows the actual capacity costs and applicable revenues compared to actual/estimated capacity costs and applicable revenues for the period January 2019 through December 2019.

Q. Please explain the variances related to capacity costs.

A. As shown in Exhibit RBD-2, page 5, line 13, column 5, the variance related to total system capacity costs is a decrease of $3.4 million or 1.3%. Below are the primary reasons for the decrease.

<u>Transmission Revenues from Capacity Sales: $2.2 million increase (Exhibit RBD-2, page 5, line 8, column 5)</u>

The variance for transmission revenues from capacity sales is primarily attributable to higher revenues from capacity premiums associated with power capacity sales of $1.2 million. The remaining variance is primarily due to higher than projected transmission revenues of $1.0 million resulting from higher than projected economy power sales.

Incremental Nuclear NRC Compliance Costs (Fukushima): O&M - $1.0 million decrease (Exhibit RBD-2, page 5, line 5, column 5)

The variance for incremental NRC compliance O&M costs is primarily attributable to deferral of Turkey Point Unit 3 and Unit 4 flooding protection modifications from 2019 to 2020.

Q. Have you included an adjustment to the 2019 CCR true-up to reflect the change to the Florida corporate income tax rate issued by the Florida Department of Revenue?

A. Yes. On September 12, 2019, the Florida Department of Revenue issued a Tax Information Publication providing notification of a reduction in the Florida corporate income tax rate, from 5.5% to 4.458%, for taxable years beginning on or after January 1, 2019, but not before January 1, 2022. The notification also states that further reduction in the tax rate is possible for taxable years beginning on or after January 1, 2020 and January 1, 2021. The reduction in the corporate income tax rate impacted the income taxes associated with the return on equity earned in the capital projects recovered through the CCR. In December 2019, FPL adjusted the CCR true-up balances for January 2019 through November 2019 to reflect the tax rate reduction. As a result, the monthly end of period true-up amounts for January 2019 through June 2019 have been adjusted downward from the amounts filed in FPL's 2019 CCR Actual/Estimated True-Up filing dated July 26, 2019.

Q. Please describe the variance in 2019 CCR revenues.

A. As shown on page 6, line 35, column 5, actual 2019 CCR revenues (net of revenue taxes), are $1.9 million higher than projected in the actual/estimated true-up filing. This is primarily due to 1,591,574 MWh higher than projected jurisdictional sales.

Q. Have you provided a schedule showing the actual monthly capacity payments by contract?

A. Yes. Schedule A12 consists of two pages that are included in Exhibit RBD-2 as pages 7 and 8. Page 7 shows the actual capacity payments for FPL's Purchase Power Agreements for the period January 2019 through December 2019. Page 8 provides the Short Term Capacity Payments for the period January 2019 through December 2019.

Q. Have you provided a schedule showing the capital structure components and cost rates relied upon by FPL to calculate the rate of return applied to all capital projects recovered through the FCR and CCR Clauses?

A. Yes. The capital structure components and cost rates used to calculate the rate of return on the capital investments for the period January 2019 through December 2019 are included on pages 19 and 20 of Exhibit RBD-2.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20200001-EI

JULY 27, 2020

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

A. My name is Renae B. Deaton. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or "the Company") as Director, Clause Recovery and Wholesale Rates, in the Regulatory & State Governmental Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

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 actual/estimated true-up amounts for the Fuel Cost Recovery ("FCR") Clause and the Capacity Cost Recovery ("CCR") Clause for the period January 2020 through December 2020. My testimony also provides a revised 2019 FCR final net true-up amount that reflects revisions to the amount filed on March 2, 2020.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits with your testimony?

A. Yes, various schedules are included in Exhibits RBD-3, RBD-4 and RBD-5.

Exhibit RBD-3 contains the FCR Schedules. These include Schedules E3 through E9 that provide revised estimates for the period July 2020 through December 2020. FCR Schedules A1 through A9 provide actual data for the period January 2020 through June 2020. The actual data was derived from the FCR A-Schedules A1 through A9 that are filed monthly with the Commission and served on all parties, which are incorporated herein by reference. The FCR schedules contained in Exhibit RBD-3 also provide the calculation of the actual/estimated true-up amount and actual/estimated variances for the period January 2020 through December 2020.

Exhibit RBD-4 contains the CCR schedules, which provide the calculation of the actual/estimated true-up amount and actual/estimated variances for the period January 2020 through December 2020.

Exhibit RBD-5 provides the calculation of the revised final net true-up amount for the period January 2019 through December 2019.

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

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

Q. Have you revised the 2019 FCR final net true-up amount that was filed in this docket on March 2, 2020?

A. Yes. The 2019 FCR final true-up amount was revised to include $89,873 associated with missing railcar lease and energy imbalance expenses. This revision decreases the actual 2019 FCR end of period true-up over-recovery amount, including interest, from $77,204,120 to $77,114,247 and increases the 2019 FCR final net true-up under-recovery amount, including interest from $51,531,817 to $51,621,690. Exhibit RBD-5 of my testimony provides the revised schedules reflecting the calculation of the revised 2019 FCR final net true-up under-recovery amount of $51,621,690.

Q. Please describe the data that FPL has used as a comparison when calculating the FCR and CCR actual/estimated true-up amounts presented in your testimony.

A. The FCR true-up calculation compares actual/estimated data consisting of actuals for January 2020 through June 2020 and revised estimates for July 2020 through December 2020 to the data reflected in FPL's midcourse correction approved by Order No. PSC-2020-0154-PCO-EI, issued on May 14, 2020. The CCR true-up calculation compares actual/estimated data consisting of actuals for January 2020 through June 2020 and revised estimates for July 2020 through December 2020 to the data reflected in FPL's original projection for the period January 2020 through December 2020 filed on September 3, 2019.

Q. Please explain the calculation of the interest provision that is applicable to the FCR and CCR true-up amounts.

A. The calculation of the interest provision follows the methodology used in calculating the interest provision for all cost recovery clauses, as previously approved by this Commission. The interest provision is the result of multiplying the monthly average true-up amount for the twelve-month period by the monthly average interest rate. The average interest rate for the months reflecting actual data is developed using the AA financial 30-day rates as published on the Federal Reserve website on the first business day of the current month and the subsequent month divided by two. The average interest rate for the projected months is the actual rate published on the first business day in July 2020, which reflects the interest rate from the last business day in June 2020.

FUEL COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the FCR 2020 actual/estimated true-up by month?

A. Yes. Exhibit RBD-3, page 1 shows the calculation of the FCR actual/estimated true-up by month for the period January 2020 through December 2020.

Q. Please explain the calculation of the FCR end-of-period net true-up and actual/estimated true-up amounts you are requesting this Commission to approve.

A. Exhibit RBD-3, page 1 shows the calculation of the FCR end-of-period net true-up and actual/estimated true-up amounts. The 2020 end-of-period net true-up amount to be carried forward to the 2021 FCR factors is an under-recovery of $20,669,910 (page 1, line 44, column 16). This $20,669,910 under-recovery includes the revised 2019 final net true-up under-recovery of $51,621,690 (Exhibit RBD-3, page 1, line 42, column 16), included in this filing as Exhibit RBD-5, and the actual/estimated true-up over-recovery, including interest, of $30,951,780 (Exhibit RBD-3, page 1, lines 39 plus 40, column 16) for the period January 2020 through December 2020.

Q. Were these calculations made in accordance with the procedures previously approved in predecessors to this Docket?

A. Yes.

Q. Have you provided a schedule showing the variances between the actual/estimated amounts and the midcourse correction amounts for 2020?

A. Yes. Exhibit RBD-3, page 2 provides a variance calculation that compares the 2020 actual/estimated period data by component to the same components from the midcourse correction filing.

Q. Please summarize the variance schedule on page 2 of Exhibit RBD-3.

A. FPL's midcourse correction filing projected jurisdictional total fuel costs and net power transactions to be $2.246 billion for 2020 (Exhibit RBD-3, page 2, line 39, column 5). The actual/estimated jurisdictional total fuel costs and net power transactions are now projected to be $2.231 billion for that period (Exhibit RBD-3, page 2, line 39, column 4). The estimated variance is due to lower than projected costs combined with higher than projected sales and revenues. Jurisdictional total fuel costs and net power transactions are estimated to be $15.2 million, or 0.7% lower than the midcourse correction estimates (Exhibit RBD-3, page 2, line 39, column 6), and jurisdictional fuel revenues applicable to the period, net of revenue taxes are projected to be $15.6 million, or 0.7% higher than the midcourse correction estimates (Exhibit RBD-3, page 2, line 36, column 6). The net impact due to the decrease in jurisdictional fuel costs and the increase in jurisdictional fuel revenues applicable to the period result in the actual/estimated true-up over-recovery of $30.9 million (Exhibit RBD-3, page 2, line 40, column 6).

Q. Please explain the variances in jurisdictional total fuel costs and net power transactions.

A. Below are the primary reasons for the $15.2 million variance in jurisdictional total fuel costs.

<u>Fuel Cost of System Net Generation: $0.744 million decrease (Exhibit RBD-3, page 2, line 1, column 6)</u>

The table below provides the detail of this variance.

FUEL VARIANCE	MAY 2020 MIDCOURSE CORRECTION	2020 ACTUAL/ESTIMATED	DIFFERENCE
<u>Heavy Oil</u>			
Cost	$10,809,864	$13,866,418	$3,056,554
MMBTU	950,703	1,271,430	320,727
$ per MMBTU	11.37	10.91	(0.46)
Variance due to consumption			$ 3,646,790
Variance due to cost			$ (590,236)
Total Variance			$ 3,056,554
<u>Light Oil</u>			
Cost	$6,810,004	$14,804,568	$7,994,564
MMBTU	435,631	1,053,796	618,165
$ per MMBTU	15.63	14.05	(1.58)
Variance due to consumption			$ 9,663,469
Variance due to cost			$ (1,668,905)
Total Variance			$ 7,994,564

FUEL VARIANCE	MAY 2020 MIDCOURSE CORRECTION	2020 ACTUAL/ESTIMATED	DIFFERENCE
Coal			
Cost	$48,159,717	$50,709,323	$2,549,606
MMBTU	18,706,307	19,137,147	430,840
$ per MMBTU	2.57	2.65	0.08
Variance due to consumption			$ 1,109,205
Variance due to cost			$ 1,440,400
Total Variance			$ 2,549,606
Natural Gas			
Cost	$2,186,682,264	$2,169,620,296	($17,061,968)
MMBTU	620,020,852	640,798,422	20,777,570
$ per MMBTU	3.53	3.39	(0.14)
Variance due to consumption			$ 73,278,090
Variance due to cost			$ (90,340,058)
Total Variance			$ (17,061,968)
Nuclear			
Cost	$144,970,704	$147,687,701	$2,716,996
MMBTU	298,230,369	307,086,334	8,855,965
$ per MMBTU	0.49	0.48	(0.01)
Variance due to consumption			$ 4,304,912
Variance due to cost			$ (1,587,916)
Total Variance			$ 2,716,996
Total System			
Total Dollar	$2,397,432,553	$2,396,688,306	($744,248)
Units (MMBTU)	938,343,862	969,347,129	31,003,267
$ per Unit	2.55	2.47	(0.08)
Variance due to consumption			$ 79,212,158
Variance due to cost			$ (79,956,405)
Total Variance			$ (744,248)

<u>Fuel Cost of Stratified Sales: $10.1 million increase (Exhibit RBD-3, page 2, line 2, column 6)</u>

The variance for the fuel cost of stratified sales is primarily attributable to higher than projected sales under stratified contracts, resulting in a larger credit to fuel costs.

<u>Fuel Cost of Power Sold: $3.3 million increase (Exhibit RBD-3, page 2, line 4, column 6)</u>

The variance of ($3,315,090) for the Fuel Cost of Power Sold is primarily attributable to higher than projected economy power sales. FPL now projects to sell 128,146 MWh more of economy power, resulting in a volume variance of ($2,088,575). The average unit fuel cost on economy power sales is now projected to be $0.34/MWh higher than originally projected, resulting in a cost variance of ($973,104). The combination of higher economy power sales and higher fuel costs attributable to economy power sales results in a total variance for economy power sales of ($3,061,679). The remaining variance of ($253,411) is attributable to higher than projected St. Lucie Plant Reliability Exchange sales and higher than projected fuel costs attributable to St. Lucie Plant Reliability Exchange sales.

<u>Energy Cost of Economy Purchases: $2.1 million decrease (Exhibit RBD-3, page 2, line 8, column 6)</u>

The variance for the Energy Cost of Economy Purchases is primarily attributable to lower than projected economy power purchases. FPL now projects to purchase 81,518 MWh less of economy power resulting in a volume variance of ($2,276,824). The average cost of economy purchases is now projected to be $0.55/MWh higher than originally projected, resulting in a cost variance of $202,936. The combination of lower economy power purchases coupled with higher costs for economy power purchases results in a net variance of ($2,073,888).

Gains from Off-System Sales: $0.691 million increase (Exhibit RBD-3, page 2, line 5, column 6)

The variance for Gains from Off-System Sales is primarily attributable to higher than projected economy power sales. FPL now projects to sell 128,146 MWh more of economy power, resulting in a volume variance of ($1,146,732). This variance is partially offset by lower than projected margins on economy power sales. FPL now projects that margins on economy power sales will be $0.16/MWh lower than originally projected, resulting in a cost variance of $455,579. The combination of higher economy power sales and lower margins on economy power sales results in a net variance for Gains from Off-System Sales of ($691,153).

Energy Payments to Qualifying Facilities: $0.250 million increase (Exhibit RBD-3, page 2, line 7, column 6)

The variance of $250,474 for Energy Payments to Qualifying Facilities is primarily attributable to higher than projected purchases from As-Available Co-Generation facilities. FPL now projects to purchase 46,027 MWh more from As-Available Co-Generation facilities, resulting in a volume variance of $673,277. This variance is partially off-set by lower than projected fuel costs from As-Available Co-Generation facilities. Fuel costs are now projected to be $1.26/MWh lower, resulting in a cost variance of ($399,594). The combination of higher purchases and lower fuel costs from As-Available Co-Generation facilities results in a net variance of $273,683. This variance is slightly offset by a variance of ($23,208) that is primarily related to lower than projected fuel costs from Firm Co-Generation facilities.

<u>Variable Power Plant O&M Attributable to Off-System Sales: $0.083 million increase (Exhibit RBD-3, page 2, line 12, column 6)</u>

The variance of $83,295 is attributable to higher than originally projected economy power sales.

<u>Variable Power Plant O&M Avoided due to Economy Purchases: $0.053 million decrease (Exhibit RBD-3, page 2, line 13, column 6)</u>

The variance of $52,987 is attributable to lower than originally projected economy power purchases.

CAPACITY COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the CCR 2020 actual/estimated true-up by month?

A. Yes. Exhibit RBD-4, page 1 provides the calculation of the CCR actual/estimated true-up by month for the period January 2020 through December 2020.

Q. Please explain the calculation of the CCR 2020 actual/estimated true-up and the end-of-period net true-up amounts you are requesting this Commission to approve.

A. Exhibit RBD-4, pages 4 and 5 shows the actual/estimated capacity costs and applicable revenues (January 2020 through June 2020 reflects actual data, while the data for July 2020 through December 2020 is based on updated estimates) compared to the original projection filing for the January 2020 through December 2020 period. The CCR revenues (net of revenue taxes) are projected to be $4,478,014 (Exhibit RBD-4, page 5, line 27, column 5) higher than FPL's original projection filing. Jurisdictional total capacity costs are estimated to be $2,790,978 lower than the original projection filing (Exhibit RBD-4, page 5, line 24, column 5). The $2,790,978 over-recovery due to lower jurisdictional capacity costs combined with the $4,478,014 increase in revenues, results in the 2020 actual/estimated true-up over-recovery amount of $7,388,454, including interest (Exhibit RBD-4, page 5, lines 32 plus 33, column 5).

As shown on Exhibit RBD-4, page 3, the 2020 end-of period net true up amount to be carried forward to the 2021 CCR factors is an over-recovery of $12,530,421 (line 14, column 15). This $12,530,421 net over-recovery is comprised of the 2019 final true-up over-recovery of $5,141,967 (line 11, column 15), and the actual/estimated true-up over-recovery, including interest, of $7,388,454 for the period January 2020 through December 2020 (lines 8 plus 9, column 15).

Q. Is this true-up calculation made in accordance with the procedures previously approved in predecessors to this docket?

A. Yes.

Q. Please explain the variances related to capacity costs.

A. As shown in Exhibit RBD-4, page 5, line 1, column 5, total system capacity costs are estimated to be $2.9 million or 1.1% less than projected in FPL's original projection filing. The variance related to the jurisdictional portion of these costs is also a 1.1% decrease from the original projection (page 5, line 24, column 6). Below are the primary reasons for the estimated $2.9 million decrease in total system capacity costs.

<u>Transmission Revenues from Capacity Sales: $1.9 million increase (Exhibit RBD-4, page 4, line 11, column 5)</u>

Approximately ($1.02 million) of the total variance is attributable to higher revenues from capacity premiums associated with power capacity sales. Higher than originally projected transmission revenues from economy sales resulted in a variance of approximately ($879,000).

<u>Incremental Nuclear NRC Compliance Costs – Capital: $1.1 million decrease (Exhibit RBD-4, page 4, line 9, column 5)</u>

The variance for incremental nuclear NRC compliance capital costs is primarily attributable to retirements during the Spring 2020 outage at Turkey Point Unit 3 that were not included in the original projections.

<u>Incremental Plant Security Costs – Capital: $0.9 million decrease (Exhibit RBD-4, page 4, line 7, column 5)</u>

The variance for incremental plant security capital costs is primarily attributable to lower than projected costs associated with the implementation of controls at FPL's 16 solar sites required by the NERC CIP Low Impact regulations (CIP-003), which became effective on January 1, 2020.

Transmission of Electricity by Others: $0.1 million decrease (Exhibit RBD-4, page 4, line 10, column 5)

The approximately ($105,000) variance is due to lower than projected costs for the purchase of third-party transmission utilized to facilitate wholesale power sales.

Incremental Plant Security Costs – O&M: $1.1 million increase (Exhibit RBD-4, page 4, line 6, column 5)

The variance for incremental plant security O&M costs is primarily attributable to costs not included in original projections associated with new NERC CIP requirements and new process improvements. The variance was partially offset by the implementation of cost savings initiatives at the St. Lucie and Turkey Point nuclear plants resulting in lower security force costs.

Incremental Nuclear NRC Compliance Costs - O&M: $0.6 million increase (Exhibit RBD-4, page 4, line 8, column 5)

The variance for incremental nuclear NRC compliance O&M costs is primarily attributable to deferral of Turkey Point Unit 3 and Unit 4 flooding protection modifications from 2019 to 2020.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENAE B. DEATON

DOCKET NO. 20200001-EI

SEPTEMBER 3, 2020

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

A. My name is Renae B. Deaton. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or "the Company") as the Director, Clause Recovery and Wholesale Rates in the Regulatory & State Governmental Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. My testimony addresses the following subjects:

- The Fuel Cost Recovery ("FCR") Clause factors for the period January 2021 through December 2021;
- The calculation of the jurisdictional amount of FPL's portion of the 2019 incentive mechanism gains to be recovered through the 2021 FCR factors;
- The Capacity Cost Recovery ("CCR") Clause factors for the period January 2021 through December 2021 and the CCR factors for the same period, including a refund for the 2018 SoBRA true-up, and an adjustment to recover the non-fuel revenue requirements associated with the Indiantown

Cogeneration L.P. facility ("Indiantown"), as approved in Order No. PSC-16-0506-FOF-EI, issued in Docket No. 160154-EI on November 2, 2016;

- The non-fuel revenue requirement calculation for Indiantown for the period January 2021 through December 2021; and
- FPL's proposed cogeneration as-available energy ("COG-1") tariff sheets, which reflect updated variable operation and maintenance expense and loss factors.

Q. Have you prepared or caused to be prepared under your direction, supervision, or control any exhibits in this proceeding?

A. Yes, I have. They are as follows:

Exhibit RBD-6 (Appendix II)

- Schedules E1, E1-A, E1-C, E1-D, E1-E, E2, Calculation of Jurisdictional Incentive Mechanism Gains – FPL Portion, RS-1 Inverted Rate Calculation, H1 and E10 provide the calculation of FCR factors for January 2021 through December 2021;
- Pages 9 through 12, which provide the 2021 Projected Energy Losses by Rate Class;
- Pages 101 and 102, which provide updated COG-1 tariff sheets;

Exhibit RBD-7 (Appendix III)

- Pages 1 through 4 provide the calculation of the 2021 CCR factors including the refund for the 2018 SoBRA true-up, and excluding the Indiantown non-fuel revenue requirements for January 2021 through December 2021;

- Pages 5 through 10 provide the calculation of depreciation and return on incremental power plant security and incremental Nuclear Regulatory Commission ("NRC") compliance capital investments;
- Page 11 provides the calculation of amortization and return on the regulatory asset related to the Cedar Bay Transaction;
- Page 12 provides the calculation of amortization and return on the regulatory liability related to the Cedar Bay Transaction;
- Page 13 provides the calculation of amortization and return on the regulatory asset related to Indiantown;
- Page 14 provides the calculation of amortization and return on the regulatory asset and liability related to St. Johns River Power Park, and the refund to customers associated with the deferred interest liability and dismantlement;
- Page 15 provides the capital structure, components and cost rates relied upon to calculate the rate of return applied to capital investments and working capital amounts included for recovery through the CCR clause for the period January 2021 through December 2021;
- Pages 18 and 19 provide the calculation of the portion of the CCR factors that recovers the non-fuel revenue requirements associated with Indiantown for the period January 2021 through December 2021;
- Page 20 combines the results from pages 1 through 4 and pages 18 and 19 to provide the total 2021 CCR factors including the non-fuel revenue requirements associated with Indiantown for the period January 2021

through December 2021;

- Pages 21 and 22 provide the calculation of the Indiantown revenue requirements for January 2021 through December 2021;
- Pages 23 through 38 provide the calculations of stratified separation factors.

FUEL COST RECOVERY CLAUSE

Q. What adjustments are included in the calculation of the 2021 FCR factors shown on Schedule E1 included in Appendix II?

A. The 2021 FCR factors include adjustments for the total net true-up, the Generating Performance Incentive Factor ("GPIF"), the jurisdictional amount associated with FPL's share of the 2019 incentive mechanism gains and the cost associated with the 2021 Subscription Credit for the FPL SolarTogether Program.

The total net true-up to be included in the 2021 FCR factors is an under-recovery of $20,669,910, as shown on line 28 of Schedule E1. This amount, divided by the projected retail sales of 111,812,880 MWh for January 2021 through December 2021, results in an increase of 0.0185 cents per kWh before applicable revenue taxes.

The GPIF testimony of witness Charles R. Rote, filed on March 16, 2020, proposes a reward of $8,125,681 for the period ending December 2019, as shown on line 32 of Schedule E1. This $8,125,681 reward, divided by the projected retail sales of 111,812,880 MWh for January 2021 through December 2021, results in an increase of 0.0073 cents per kWh.

FPL is including $8,703,535 for the jurisdictional amount associated with its share of 2019 incentive mechanism gains in the calculation of its 2021 FCR factors, as shown on line 33 of Schedule E1. As presented and explained in the direct testimony and exhibits of FPL witness Gerard J. Yupp filed on March 2, 2020 in this docket, FPL's activities under the incentive mechanism in 2019 delivered $55,249,313 in total gains. Of these total gains, FPL is allowed to retain $9,149,588 (system amount) per Order No. PSC-13-0023-S-EI dated January 14, 2013 and Order No. PSC-16-0560-AS-EI dated December 15, 2016. FPL will reflect recovery of one-twelfth of the approved jurisdictional amount of $8,703,535, net of revenue taxes, in each month's Schedule A2 for the period January 2021 through December 2021 as a reduction to jurisdictional fuel revenues applicable to each period. The calculation of the jurisdictional amount of the 2019 incentive mechanism gains adjusted for revenue taxes is shown on page 4 of Appendix II. This $8,703,535, divided by the projected retail sales of 111,812,880 MWh for January 2021 through December 2021, results in an increase of 0.0078 cents per kWh.

Per the Settlement Agreement approved in Order No. PSC-2020-0084-S-EI, issued in Docket No. 20190061 on March 20, 2020, FPL has included $98,939,400 (adjusted for revenue taxes) associated with the 2021 Subscription Credit for the

FPL SolarTogether Program, as shown on line 34 of Schedule E1. The subscription credit reflects the estimated economic value of the program's solar power plants on FPL's system, which consists of reduced fuel, purchased power, and carbon emission costs. As approved in Order No. PSC-2020-0084-S-EI, the subscription credit is to be recovered through FPL's fuel cost recovery clause, partially offsetting system savings resulting from the addition of the program's solar power plants. This $98,939,400, divided by the projected retail sales of 111,812,880 MWh for January 2021 through December 2021, results in an increase of 0.0885 cents per kWh.

Schedule E2 provides the monthly fuel factors as well as the levelized FCR factor for 2021. Schedule E-1E provides the calculation of the 2021 FCR factors by rate group for each period.

Q. Please explain the fuel cost of stratified sales amount reflected on line 2 of Schedule E1.

A. FPL has included a credit of $14,823,385 associated with stratified wholesale power sales contracts in effect in 2021. The fuel costs for wholesale power contracts are calculated based on a guaranteed heat rate and a fuel price index. 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 cost of the stratified sales are not recovered on an average system cost basis, an adjustment has been made to remove these costs and the related kWh sales from the fuel adjustment calculation. This adjustment was performed in the same manner that off-system sales are removed from the calculation, consistent with Order No. PSC-97-0262-FOF-EI.

CAPACITY COST RECOVERY CLAUSE

Q. Have you prepared a summary of the requested capacity costs for the projected period of January 2021 through December 2021?

A. Yes. Pages 1 and 2 of Appendix III provides this summary. Total recoverable capacity costs for the period January 2021 through December 2021 are $213,002,247 (page 2, line 32). This includes $237,781,299 for 2021 projected jurisdictional capacity costs, the net true-up over-recovery for 2019 and 2020 of $12,530,421 (line 27 plus line 28), a $12,401,882 refund associated with the 2018 SoBRA true-up (line 29), and revenue taxes. This $213,002,247 excludes the 2021 Indiantown non-fuel revenue requirements.

Q. **Please describe the adjustment associated with the true-up of the 2018 SoBRA.**

A. Pursuant to the 2016 Base Rate Settlement Agreement, a true-up of the SoBRA is required if actual capital costs are lower than projected. As such, FPL has included a credit of $12.4 million, including interest, (Appendix III, page 2, line 29) for the true-up of 2018 SoBRA costs as a reduction in the calculation of its 2021 CCR factors. The calculation of this credit is discussed in the declaration of Edward J. Anderson.

Q. What are the projected Indiantown jurisdictional non-fuel revenue requirements for the January 2021 through December 2021 period?

A. The jurisdictional non-fuel revenue requirements for January 2021 through December 2021 are $1,356,055. The calculation of this amount is shown on Exhibit RBD-7, Appendix III. FPL has made an adjustment for the Indiantown non-fuel revenue requirements consistent with the method previously used when the West County Energy Center Unit 3 non-fuel revenue requirements were recovered through the CCR as approved in Order No. PSC-13-0023-S-EI, issued in Docket No. 120015-EI on January 14, 2013.

Q. Please describe the Weighted Average Cost of Capital ("WACC") that is used in the calculation of the return on the 2021 capital investments included for recovery.

A. FPL calculated and applied a projected 2021 WACC in accordance with the methodology established in Commission Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU, issued on May 20, 2020 ("2020 WACC Order"). Pursuant to the 2020 WACC Order, the WACC was calculated using the currently approved mid-point return on equity and the proration formula prescribed by Treasury Regulation §1.167(l)-1(h)(6)(i) applied to the plant only depreciation-related Accumulated Deferred Federal Income Tax balances included in the capital structure. This projected WACC is used to calculate the rate of return applied to the 2021 CCR capital investments. The projected capital structure, components and cost rates used to calculate the rate of return are provided on page 15 of Exhibit RBD-7 in Appendix III.

Q. Have you provided a calculation of 2021 CCR factors by rate class including an adjustment to recover the non-fuel revenue requirements associated with

Indiantown for the period January 2021 through December 2021?

A. Yes. As approved in Order No. PSC-16-0506-FOF-EI, FPL has included on pages 18 and 19 of Exhibit RBD-7, Appendix III, the 2021 non-fuel revenue requirements associated with Indiantown of $1,356,055. Page 20 of Exhibit RBD-7, Appendix III, shows the calculation of the 2021 CCR factors including the non-fuel revenue requirements associated with Indiantown for the period January 2021 through December 2021.

Q. Has FPL accounted for stratified wholesale power sales contracts in the jurisdictional separation of projected 2021 capacity costs?

A. Yes. FPL has separated the production-related capacity costs based on stratified separation factors that better reflect the types of generation required to serve load under stratified wholesale power sales contracts. The use of stratified separation factors thus results in a more accurate separation of capacity costs between the retail and wholesale jurisdictions. The stratified separation factors are provided in Appendix III, pages 23-38.

Q. Have you prepared a calculation of the allocation factors for demand and energy?

A. Yes. Page 3 of Appendix III provides this calculation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate class contributes to total kWh sales, as adjusted for losses.

Q. What are the effective dates that FPL is requesting for the new FCR and CCR factors for 2021?

A. FPL is requesting that the FCR factors and the CCR factors for the period January 2021 through December 2021 become effective starting with meter readings made on or after January 1, 2021. These factors should remain in effect until modified by this Commission.

Proposed 2021 Residential Bill

Q. What is FPL's proposed residential 1,000 kWh bill for the period January 2021 through December 2021?

A. FPL's proposed residential 1,000 kWh bill for January 2021 through December 2021 is $99.05. This proposed bill includes a base rate charge of $69.90, which reflects a reduction of $0.04 associated with the true-up of FPL's 2018 SoBRA project, an FCR charge of $21.23, a CCR charge of $2.04, an environmental cost recovery charge of $1.49, a conservation cost recovery charge of $1.49, a storm protection plan cost recovery charge of $0.42 and gross receipts tax of $2.48. FPL's proposed residential 1,000 kWh bill for 2021 is provided on Schedule E-10, which is page 99 of Appendix II.

Q. Does this conclude your testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Gerald J. Yupp was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 20200001-EI

MARCH 2, 2020

Q. Please state your name and address.

A. My name is Gerard J. Yupp. My business address is 700 Universe Boulevard, Juno Beach, Florida, 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power and Light Company ("FPL") as Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Please summarize your educational background and professional experience.

A. I graduated from Drexel University with a Bachelor of Science Degree in Electrical Engineering in 1989. I joined the Protection and Control Department of FPL in 1989 as a Field Engineer where I was responsible for the installation, maintenance, and troubleshooting of protective relay equipment for generation, transmission and distribution facilities. While employed by FPL, I earned a Masters of Business Administration degree from Florida Atlantic University in 1994. In 1996, I joined the Energy Marketing and Trading Division ("EMT") of FPL as a real-time power trader. I progressed through several power trading positions and assumed the lead role for power trading in 2002. In 2004, I became the Director of Wholesale Operations and natural gas and fuel oil procurement and operations were added to my responsibilities. I have been in my current role since 2008. On the operations side, I am responsible for the procurement and management of all natural gas and fuel oil for FPL, as well as all short-term power trading activity. Finally, I am responsible for the oversight of FPL's optimization activities associated with the Incentive Mechanism.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the 2019 results of FPL's activities under the Incentive Mechanism that was originally approved by Order No. PSC-13-0023-S-EI, dated January 14, 2013, in Docket No. 120015-EI and approved for continuation, with certain modifications, by Order No. PSC-16-0560-AS-EI, dated December 15, 2016, in Docket No. 160021-EI.

Q. Have you prepared or caused to be prepared under your supervision, direction and control any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibit:

- GJY-1, consisting of 4 pages:
    - Page 1 – Total Gains Schedule
    - Page 2 – Wholesale Power Detail
    - Page 3 – Asset Optimization Detail
    - Page 4 – Incremental Optimization Costs

Q. Please provide an overview of the Incentive Mechanism.

A. The Incentive Mechanism is an expanded optimization program that is designed to create additional value for FPL's customers while also providing an incentive to FPL if certain customer-value thresholds are achieved. The Incentive Mechanism includes gains from wholesale power sales and savings from wholesale power purchases, as well as gains from other forms of asset optimization. These other forms of asset optimization include, but are not limited to, natural gas storage optimization, natural gas sales, capacity releases of natural gas transportation, capacity releases of electric transmission and potentially capturing additional value from a third party in the form of an Asset Management Agreement (AMA).

Q. Please describe the modifications that were made to the Incentive Mechanism in FPL's 2016 rate case and approved by Order No. PSC-16-0560-AS-EI.

A. There were two specific modifications made to the Incentive Mechanism in FPL's 2016 rate case. First, the sharing threshold was reduced from $46 million to $40 million. The sharing intervals and percentages remained unchanged from the original Incentive Mechanism. Under the modified Incentive Mechanism, customers continue to receive 100% of the gains up to the new sharing threshold of $40 million. Incremental gains above $40 million continue to be shared between FPL and customers as follows: customers receive 40% and FPL receives 60% of the incremental gains between $40 million and $100 million; and customers receive 50% and FPL receives 50% of all incremental gains above $100 million.

The second modification that was made to the Incentive Mechanism involved variable power plant O&M costs. Under the original Incentive Mechanism, FPL was allowed to recover variable power plant O&M costs incurred to make wholesale sales above 514,000 MWh (the level of wholesale sales that were assumed in forecasting FPL's 2013 test year power plant O&M costs in the MFRs filed in FPL's 2012 rate case). Under the modified Incentive Mechansim, FPL nets economy sales and purchases and recovers the net amount of variable power plant O&M incurred during the year. For example, if economy purchases are greater than economy sales, customers receive a credit for the net variable power plant O&M that has been saved during the year. The per-MWh variable power plant O&M rate that FPL uses to calculate these costs, as described in FPL's 2017 Test Year MFR's filed with the 2016 Rate Petition is $0.65/MWh.

FPL continues to be allowed to recover reasonable and prudent incremental O&M costs incurred in implementing the expanded optimization program under the Incentive Mechanism, including incremental personnel, software and associated hardware costs.

Q. Please summarize the activities and results of the Incentive Mechanism for 2019?

A. FPL's activities under the Incentive Mechanism in 2019 delivered $55,249,313 in total gains. During 2019, FPL's activities under the Incentive Mechanism included wholesale power purchases and sales, natural gas sales in the market and production areas, gas storage utilization, and the capacity release of firm natural gas transportation. Additionally, FPL entered into several Asset Management Agreements related to a small portion of upstream gas transportation during 2019. The total gains of $55,249,313 exceeded the sharing threshold of $40 million. Therefore, the incremental gains above $40 million will be shared between customers and FPL, 40% and 60%, respectively. Exhibit GJY-1, Page 1, shows monthly gain totals, threshold levels and the final gains allocation for 2019.

Q. Please provide the details of FPL's wholesale power activities under the Incentive Mechanism for 2019.

A. The details of FPL's 2019 wholesale power sales and purchases are shown separately on Page 2 of Exhibit GJY-1. FPL had gains of $23,922,292 on wholesale sales and savings of $14,914,467 on wholesale purchases for the year.

Q. Please provide the details of FPL's asset optimization activities under the Incentive Mechanism for 2019.

A. The details of FPL's 2019 asset optimization activities are shown on Page 3 of Exhibit GJY-1. FPL had a total of $16,412,555 of gains that were the result of seven different forms of asset optimization.

Q. Did FPL engage in any new forms of asset optimization during 2019?

A. No. FPL did not engage in any new forms of asset optimization activities during 2019.

Q. Did FPL incur incremental O&M expenses related to the operation of the Incentive Mechanism in 2019?

A. Yes. FPL incurred personnel expenses of $474,309 related to the costs associated with an additional two and one-half personnel required to support FPL's expanded activities under the Incentive Mechanism. FPL also incurred $58,755 in expenses related to licensing fees of OATI WebTrader software. In total, FPL incurred incremental O&M expenses related to the operation of the Incentive Mechanism of $533,064 in 2019.

On the variable power plant O&M side, FPL's actual net economy power sales and purchases totaled 2,147,694 MWh (2,698,881 MWh of economy sales and 551,187 MWh of economy purchases), resulting in net variable power plant O&M costs of $1,396,001 for 2019.

Q. Overall, were FPL's activities under the Incentive Mechanism successful in 2019?

A. Yes. FPL's activities under the Incentive Mechanism were highly successful in 2019. On the wholesale power side, suitable market conditions in the winter period helped drive strong wholesale power sales and high customer demand during the late spring, early summer, and late summer periods provided the opportunity to purchase lower cost power from the market to avoid running more expensive generation. Overall, FPL was able to consistently capitalize on power market opportunities throughout the year to deliver slightly more than $38.8 million in customer benefits. Market opportunities for asset optimization activities related to natural gas were fairly consistent throughout the year and resulted in significant customer benefits of more than $16.4 million. In total, these activities delivered $55,249,313 of gains, which contrast very favorably to the total optimization expenses (personnel and variable power plant O&M) of $1,929,065.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF GERARD J. YUPP

DOCKET NO. 20200001-EI

SEPTEMBER 3, 2020

Q. Please state your name and address.

A. My name is Gerard J. Yupp. My business address is 700 Universe Boulevard, Juno Beach, Florida, 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power and Light Company ("FPL") as Senior Director of Wholesale Operations in the Energy Marketing and Trading Division.

Q. Have you previously testified in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain FPL's projections for (1) the dispatch costs of heavy fuel oil, light fuel oil, coal and natural gas; (2) the availability of natural gas to FPL; (3) generating unit heat rates and availabilities; and (4) the quantities and costs of wholesale (off-system) power sales and purchased power transactions. Additionally, my testimony addresses the Incentive Mechanism results for 2019 and the Incremental Optimization Costs included in FPL's 2021 Projection Filing pursuant to the Incentive Mechanism that was approved in Order No. PSC-16-0560-AS-EI dated December 15, 2016

("2016 Base Rate Settlement Agreement").

Q. Have you prepared or caused to be prepared under your supervision, direction and control any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

- GJY-2: Appendix I

and I am co-sponsoring:

- Schedules E2 through E9 of Appendix II included in Renae Deaton's Exhibit RBD-6 and Appendix III included in Renae Deaton's Exhibit RBD-7.

<u>FUEL PRICE FORECAST</u>

Q. What forecast methodologies has FPL used for the 2021 recovery period?

A. For natural gas commodity prices, the forecast methodology relies upon the NYMEX Natural Gas Futures contract prices (forward curve). For light and heavy fuel oil prices, FPL utilizes Over-The-Counter ("OTC") forward market prices. Projections for the price of coal are based on actual coal purchases and price forecasts developed by J.D. Energy. Forecasts for the availability of natural gas are developed internally at FPL and are based on contractual commitments and market experience. The forward curves for both natural gas and fuel oil represent expected future prices at a given point in time. The basic assumption made with respect to using the forward curves is that all available data that could impact the price of natural gas and fuel oil in the short-term is incorporated into the curves at all times. FPL utilized forward curve prices from the close of business on July 1, 2020 for calculating its 2021 Fuel Cost Recovery ("FCR") Clause factors.

Q. Has FPL used these same forecasting methodologies previously?

A. Yes. FPL began using the NYMEX Natural Gas Futures contract prices (forward curve) and OTC forward market prices in 2004 for its 2005 projections and has used this methodology consistently since that time.

Q. What are the factors that can affect FPL's natural gas prices during the January through December 2021 period?

A. In general, the key physical factors are (1) North American natural gas demand and domestic production; (2) the level of working gas in underground storage throughout the period; (3) weather (particularly in the winter period); (4) the potential for imports and/or exports of natural gas; and (5) the terms of FPL's natural gas supply and transportation contracts.

In its August 2020 Short-Term Energy Outlook, the Energy Information Administration ("EIA") forecasts Henry Hub natural gas spot prices will average approximately $2.03 per MMBtu in 2020. The EIA expects that natural gas prices will generally rise through the end of 2021, with the sharpest increases occurring during the fall and winter of 2020-2021. The EIA forecasts that Henry Hub spot prices will average $3.14 per MMBtu in 2021. U.S. dry natural gas production is estimated to decline from a forecasted average of 88.7 BCF/day in 2020 to 84 BCF/day in 2021.

Natural gas consumption is forecast to decrease by approximately 3% by year-end 2020 (compared to year-end 2019). For 2020, the largest decrease in natural gas consumption occurs in the industrial sector as a result of reduced manufacturing activity. The overall decline also reflects lower heating demand in early 2020, contributing to lower overall residential and commercial demand. While consumption in 2021 among the residential, commercial, and industrial sectors is expected to increase from 2020 levels, demand in the electric power sector is projected to decrease in response to higher natural gas prices. Overall, natural gas consumption in 2021 is projected to decrease compared to 2020 consumption levels. Natural gas storage levels ended July 2020 at roughly 3.3 trillion cubic feet, 15% higher than than the five-year average. Natural gas storage levels are expected to reach approximately 4.0 trillion cubic feet at the end of October 2020.

Q. Please describe FPL's natural gas transportation portfolio for the January through December 2021 period.

A. FPL utilizes the Florida Gas Transmission Company, LLC ("FGT"), Gulfstream Natural Gas System, LLC ("Gulfstream"), Sabal Trail Transmission, LLC ("Sabal Trail"), and Florida Southeast Connection, LLC ("FSC") pipelines to deliver natural gas to its generation facilities. FPL's total firm transportation capacity ranges from 1,150,000 to 1,274,000 MMBtu/day on FGT, 695,000 MMBtu/day on Gulfstream and 600,000 MMBtu/day on Sabal Trail/FSC. Additionally, FPL projects that during the January through December 2021 period, varying levels of non-firm natural gas transportation capacity will be available, depending on the month.

FPL also has firm transportation capacity on several upstream pipelines that provide FPL access to on-shore gas supply. FPL has 80,000 MMBtu/day of firm transport on the Southeast Supply Header ("SESH") pipeline, 196,500 MMBtu/day (January through October) and 121,500 MMBtu/day (November through December) of firm transport on the Transcontinental Gas Pipe Line Company, LLC ("Transco") Zone 4A lateral, and 319,000 MMBtu/day (January through March), 464,000 MMBtu/day (April through October), and 299,000 MMBtu/day (November through December) of firm transport on the Gulf South Pipeline Company, LP ("Gulf South") pipeline. The firm transportation on the SESH, Transco, and Gulf South pipelines does not increase transportation capacity into the state; however, FPL's firm transportation rights on these pipelines provide access for up to 740,500 MMBtu/day during the summer season of on-shore natural gas supply, which helps diversify FPL's natural gas portfolio and enhance the reliability of fuel supply.

Q. Please describe FPL's natural gas storage position.

A. FPL currently holds 4.0 billion cubic feet ("BCF") of firm natural gas storage capacity in Bay Gas Storage, located in southwest Alabama and 1.0 BCF of firm natural gas storage capacity in Southern Pines Energy Center, located in southeast Mississippi. While the acquisition of upstream transportation capacity (i.e., Gulf South) has helped mitigate a large portion of risk associated with off-shore natural gas supply, natural gas storage capacity remains an important part of FPL's gas portfolio. As FPL's reliance on natural gas has increased, the importance of natural gas storage in helping balance consumption "swings" due to weather and unit availability has also increased. Storage capacity improves reliability by providing a relatively inexpensive insurance policy against supply and infrastructure problems while also increasing FPL's ability to manage supply and demand on a daily basis.

Q. What are FPL's projections for the dispatch cost and availability of natural gas for the January through December 2021 period?

A. FPL's projections of the system average dispatch cost and availability of natural gas, by transport type, by pipeline and by month, are provided on page 3 of Appendix I.

Q. What are the key factors that could affect FPL's price for heavy fuel oil during the January through December 2021 period?

A. The key factors that could affect FPL's price for heavy oil are (1) worldwide demand for crude oil and petroleum products (including domestic heavy fuel oil); (2) non-OPEC crude oil supply; (3) the extent to which OPEC adheres to its quotas and reacts to fluctuating demand for OPEC crude oil; (4) the political and civil tensions in the major producing areas of the world like the Middle East and West Africa; (5) the availability of refining capacity; (6) the price relationship between heavy fuel oil and crude oil; (7) the supply and demand for heavy oil in the domestic market; (8) the terms of FPL's supply and fuel transportation contracts; and (9) domestic and global inventory.

In its August 2020 Short-Term Energy Outlook report, the EIA forecasts West Texas Intermediate crude oil prices will average approximately $38.50 per barrel in 2020 and $45.53 per barrel in 2021. The EIA anticipates global crude oil and other liquid fuels production to decrease by 6.4 million barrels per day in 2020 and increase by 5.2 million barrels per day in 2021, with consumption decreasing by approximately 8.1 million barrels per day in 2020 and increasing by 7.0 million barrels per day in 2021. U.S. crude oil production is projected to decrease by roughly 1.0 million barrels per day in 2020 and decrease by 0.12 million barrels per day in 2021. As always, an increase in geopolitical concerns could create upward pressure on oil prices.

Q. Please provide FPL's projection for the dispatch cost of heavy fuel oil for the January through December 2021 period.

A. FPL's projection for the system average dispatch cost of heavy fuel oil, by month, is provided on page 3 of Appendix I.

Q. What are the key factors that could affect the price of light fuel oil?

A. The key factors are similar to those described for heavy fuel oil.

Q. Please provide FPL's projection for the dispatch cost of light fuel oil for the January through December 2021 period.

A. FPL's projection for the system average dispatch cost of light oil, by month, is provided on page 3 of Appendix I.

Q. What is the basis for FPL's projections of the dispatch cost of coal for Plant Scherer?

A. FPL's projected dispatch costs are based on FPL's price projection for spot coal delivered to the plant.

Q. Please provide FPL's projection for the dispatch cost of coal at Plant Scherer for the January through December 2021 period.

A. FPL's projection for the system average dispatch cost of coal for this period, by month, is shown on page 3 of Appendix I.

Q. Do the fuel costs reflected on Schedule E3 for heavy oil, light oil and coal differ from the dispatch costs shown on page 3 of Appendix I?

A. Yes. FPL maintains inventories of those fuels and runs its plants out of that inventory. The dispatch costs reflect what FPL would pay to replace fuel that is removed from inventory to run the plants. On the other hand, the "charge out" costs for heavy oil, light oil and coal that are reflected on Schedule E3 are based on FPL's weighted average inventory cost, by month, for each fuel type.

<u>PLANT HEAT RATES, OUTAGE FACTORS, PLANNED OUTAGES, AND CHANGES IN GENERATING CAPACITY</u>

Q. Please describe how FPL developed the projected Average Net Heat Rates shown on Schedule E4 of Appendix II.

A. The projected Average Net Heat Rates were calculated by the GenTrader model. The current heat rate equations and efficiency factors for FPL's generating units, which present heat rate as a function of unit power level, were used as inputs to GenTrader for this calculation. The heat rate equations and efficiency factors are updated as appropriate based on historical unit performance and projected changes due to plant upgrades, fuel grade changes, and/or from the results of performance tests.

Q. Are you providing the outage factors projected for the period January through December 2021?

A. Yes. This data is shown on page 4 of Appendix I.

Q. How were the outage factors for this period developed?

A. The unplanned outage factors were developed using the actual historical full and partial outage event data for each of the units. The historical unplanned outage factor of each generating unit was adjusted, as necessary, to eliminate non-recurring events and recognize the effect of planned outages to arrive at the projected factor for the period January through December 2021.

Q. Please describe the significant planned outages for the January through December 2021 period.

A. Planned outages at FPL's nuclear units are the most significant in relation to fuel cost recovery. St. Lucie Unit 1 is scheduled to be out of service from April 12, 2021 until May 16, 2021, or 34 days during the period. St Lucie Unit 2 is scheduled to be out of service from August 30, 2021 until October 4, 2021, or 35 days during the period. Turkey Point Unit 3 is scheduled to be out of service from October 4, 2021 until November 2, 2021, or 29 days during the period.

Q. Please identify any changes to FPL's fossil generation capacity projected to take place during the January through December 2021 period.

A. As shown in FPL's 2020 Ten Year Power Plant Site Plan (Table ES-1, page 16), FPL projects a net increase in its 2021 summer firm capacity of 577 MW. This increase is primarily related to the addition of 539 MW of firm capacity of solar generation.

WHOLESALE (OFF-SYSTEM) POWER AND PURCHASED POWER TRANSACTIONS

Q. Are you providing the projected wholesale (off-system) power sales and purchased power transactions forecasted for January through December 2021?

A. Yes. This data is shown on Schedules E6, E7, E8, and E9 of Appendix II of this filing.

Q. In what types of wholesale (off-system) power transactions does FPL engage?

A. FPL purchases power from the wholesale market when it can displace higher cost generation with lower cost power from the market. FPL will also sell excess power into the market when its cost of generation is lower than the market. FPL's customers benefit from both purchases and sales as savings on purchases and gains on sales are credited to customers through the Fuel Cost Recovery Clause. Power purchases and sales are executed under specific tariffs that allow FPL to transact with a given entity. Although FPL primarily transacts on a short-term basis (hourly and daily transactions), FPL continuously searches for all opportunities to lower fuel costs through purchasing and selling wholesale power, regardless of the duration of the transaction.

Q. Please describe the method used to forecast wholesale (off-system) power purchases and sales.

A. The quantity of wholesale (off-system) power purchases and sales are projected based upon estimated generation costs, generation availability, fuel availability, expected market conditions and historical data.

Q. What are the forecasted amounts and costs of wholesale (off-system) power sales?

A. FPL has projected 2,598,470 MWh of wholesale (off-system) power sales for the period of January through December 2021. The projected fuel cost related to these sales is $52,303,995. The projected transaction revenue from these sales is $84,634,486. After taking into account the transmission costs and capacity revenues for those sales, the projected gain is $25,272,200.

Q. In what document are the fuel costs for wholesale (off-system) power sales transactions reported?

A. Schedule E6 of Appendix II provides the total MWh of energy, total dollars for fuel adjustment, total cost and total gain for wholesale (off-system) power sales.

Q. What are the forecasted amounts and costs of wholesale (off-system) power purchases for the January to December 2021 period?

A. The costs of these economy purchases are shown on Schedule E9 of Appendix II. For the period, FPL projects it will purchase a total of 347,180 MWh at a cost of $9,019,180. If FPL generated this energy, FPL estimates that it would cost $10,519,080. Therefore, these purchases are projected to result in savings of $1,499,900.

Q. Does FPL have additional agreements for the purchase of electric power and energy that are included in your projections?

A. Yes. FPL purchases energy under two contracts with the Solid Waste Authority of Palm Beach County ("SWA"). In addition, FPL contracts to purchase and sell nuclear energy under the St. Lucie Plant Nuclear Reliability Exchange Agreements with Orlando Utilities Commission ("OUC") and Florida Municipal Power Agency. Lastly, FPL purchases energy and capacity from Qualifying Facilities under existing tariffs and contracts.

Q. Please provide the projected energy costs to be recovered through the Fuel Cost Recovery Clause for the power purchases referred to above during the January through December 2021 period.

A. Energy purchases under the SWA agreements are projected to be 904,028 MWh for the period at an energy cost of $27,268,678. FPL's cost for energy purchases under the St. Lucie Plant Reliability Exchange Agreements is a function of the operation of St. Lucie Unit 2 and the fuel costs to the owners. For the period, FPL projects purchases of 573,685 MWh at a cost of $2,641,298. These projections are shown on Schedule E7 of Appendix II.

In addition, as shown on Schedule E8 of Appendix II, FPL projects that purchases from Qualifying Facilities for the period will provide 312,315 MWh at a cost of $5,919,852.

Q. How does FPL develop the projected energy costs related to purchases from Qualifying Facilities?

A. For those contracts that entitle FPL to purchase "as-available" energy, FPL used its fuel price forecasts as inputs to the GenTrader model to project FPL's avoided energy cost that is used to set the price of these energy purchases each month. For those contracts that enable FPL to purchase firm capacity and energy, the applicable Unit Energy Cost mechanisms prescribed in the contracts are used to project monthly energy costs.

Q. What are the forecasted amounts and cost of energy being sold under the St. Lucie Plant Reliability Exchange Agreement?

A. FPL projects to sell 571,679 MWh of energy at a cost of $2,826,064. These projections are shown on Schedule E6 of Appendix II.

HEDGING/ RISK MANAGEMENT PLAN

Q. Has FPL filed a Hedging Activity Final True-Up Report for 2019 or a risk management plan for 2021, consistent with the Hedging Order Clarification Guidelines, as required by Order No. PSC-08-0667-PAA-EI issued on October 8, 2008?

A. No. FPL's fuel hedging program is under a moratorium. Therefore, FPL had no hedging activity to report for 2019, had no hedging activity in 2020, and does not plan to hedge in 2021.

THE INCENTIVE MECHANISM

Q. What were the results of FPL's asset optimization activities under the Incentive Mechanism in 2019?

A. FPL's asset optimization activities in 2019 delivered total benefits of $55,249,313. The total gains exceeded the sharing threshold of $40 million and, therefore, the gains above $40 million will be shared between customers and FPL on a 40%/60% basis, respectively. In total, customers will receive $45,924,933 (net of FPL's share of the gain above the $40 million threshold, and after incremental personnel, software, and hardware expenses are removed), and FPL will receive $9,149,588. FPL's share of the gain is included for recovery in FPL's 2021 FCR Clause factors.

Q. Did the Incentive Mechanism allow FPL to deliver greater value to customers in 2019?

A. Yes. I have compared how customers would have fared under the prior wholesale-sales sharing mechanism with the results FPL has achieved under the Incentive Mechanism. For the purpose of this comparison, I have included the same savings of approximately $40.6 million from optimization activities for power sales, power purchases and releases of electric transmission capacity under both mechanisms, as FPL was engaging in those activities prior to the Commission's approval of the Incentive Mechanism. For those savings, the previous sharing mechanism would have yielded net benefits to FPL's customers of $40.4 million, while FPL would have received $0.2 million in benefits because the three-year rolling average threshold for wholesale sales would have been exceeded.

In contrast, under the Incentive Mechanism, FPL also is incented to pursue beneficial natural gas transportation, storage and trading activities. These activities generated slightly more than $16.4 million of additional savings in 2019. When one takes into account these additional savings, less FPL's recovery of incremental optimization costs, the result is that FPL's customers received slightly more than $45.9 million of savings under the Incentive Mechanism. This is $5.5 million more than customers would have received if the prior sharing mechanism were still in effect, clear proof that the Incentive Mechanism is working to deliver added value for customers as FPL and the Commission envisioned when it was approved.

Q. Has FPL included in its 2021 FCR factors, projections of the savings that it will achieve under the Incentive Mechanism?

A. Yes. FPL has included projections for savings on wholesale power purchases (Schedule E9), projections for gains on wholesale power sales (Schedule E6), and projections for other types of asset optimization measures (Schedule E3) for 2021.

Q. Has FPL included in its 2021 FCR factors, projections of the Incremental Optimization Costs that it will incur under the Incentive Mechanism?

A. Yes. FPL has included in its 2021 FCR factors, Incremental Optimization Costs from two categories: (i) incremental personnel, software and hardware costs associated with managing the various asset optimization activities, and

(ii) variable power plant O&M ("VOM") costs associated with wholesale economy sales and purchases.

Q. Please describe the costs that are included in FPL's projections for incremental personnel, software and hardware expenses.

A. FPL projects to incur incremental expenses of $451,676 in 2021 for the salaries and expenses related to employees who were added in 2013 to support the Incentive Mechanism.

Q. Please describe the costs that are included in FPL's projections for VOM expenses.

A. Consistent with Paragraph 15 of the 2016 Base Rate Settlement Agreement, FPL has included for recovery in its 2021 FCR factors, VOM expenses that reflect the netting of economy sales and purchases. As shown on Schedules E6 and E9 of Appendix II, FPL projects to sell 2,598,470 MWh and purchase 347,180 MWh of economy power. Therefore, applying FPL's VOM rate of $0.65/MWh, FPL projects to incur VOM expenses of $1,689,006 associated with its economy sales and to avoid ($225,667) with its economy purchases. FPL has included for recovery the net of these two figures, $1,463,339 (Schedule E2, Sum of Line Nos. 14 and 15), in its 2021 FCR factors.

Q. Does this conclude your testimony?

A. Yes it does.

(Whereupon, prefiled direct testimony of Charles Rote was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF CHARLES R. ROTE

DOCKET NO. 20200001-EI

MARCH 16, 2020

Q. Please state your name and business address.

A. My name is Charles R. Rote, and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company ("FPL"), as Business Services Director in the Power Generation Division.

Q. Please summarize your educational background and professional experience.

A. I graduated from DePauw University with a Bachelor's degree in Industrial Psychology in 1991. I subsequently earned a Master of Business Administration from Pace University in New York in 1994. I am a Certified Public Accountant in the state of New York. Prior to joining FPL in 2009, I held various auditing positions at Price Waterhouse LLP and Pfizer Inc. From 1999 to 2009, I worked for Rinker Materials (acquired by Cemex in 2008) in various audit, accounting and development capacities. I have been in my current role at FPL since 2009 where I have responsibility for all budgeting, forecasting, regulatory and internal controls activities for FPL's fossil generating assets. Since 2013, I have also overseen the preparation and filing of the Generating Performance Incentive Factor ("GPIF") documents including testimony, exhibits, audits and discovery.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to report FPL's actual 2019 performance for Equivalent Availability Factor ("EAF") and Average Net Operating Heat Rate ("ANOHR") for the twelve generating units used to determine its GPIF and to calculate the resulting GPIF reward. I compared the performance of each unit to the targets approved in the final Commission Order No. PSC-2018-0610-FOF-EI issued December 26, 2018 for the period January through December 2019, and performed the reward/penalty calculations prescribed by the GPIF Manual. My testimony presents the result of these calculations: $16,250,444 of fuel savings to FPL's customers as a result of the availability and efficiency of FPL's GPIF generating units, and a GPIF reward of $8,125,681.

Q. Have you prepared, or caused to have prepared under your direction, supervision, or control any exhibits in this proceeding?

A. Yes. Exhibit CRR-1 shows the reward/penalty calculations. Page 1 of Exhibit CRR-1 is an index to the contents of the exhibit.

Q. Please explain in general terms how the total GPIF reward/penalty amount was calculated.

A. The steps involved in making this calculation are provided in Exhibit CRR-1. Page 2 provides the GPIF Reward/Penalty Table (Actual), which shows an overall GPIF performance point value of +3.4115, $16,250,444 in fuel savings and a GPIF reward of $8,125,681. Page 3 provides the calculation of the maximum allowed incentive dollars as approved by Commission Order No. PSC-13-0665-FOF-EI issued December 18, 2013. The calculation of the system actual GPIF performance points is shown on page 4. This page lists each GPIF unit, the unit's EAF and ANOHR, the weighting factors, and the associated GPIF unit points.

Page 5 is the actual EAF and adjustments summary. This page, in columns 1 through 5, lists each of the twelve GPIF units, the actual outage factors and the actual EAF for each unit. Column 6 is the adjustment for planned outage variation. Column 7 is the adjusted actual EAF, which is calculated on page 6. Column 8 is the target EAF. Column 9 contains the Generating Performance Incentive Points for availability as determined by interpolating from the tables shown on pages 8 through 19. These tables are based on the targets and target ranges previously approved by the Commission.

Continuing with Exhibit CRR-1, page 7 shows the adjustments to ANOHR. For each GPIF unit it shows, in columns 2 through 4, the target heat rate formula, and the actual net output factor ("NOF") and ANOHR for all units. Since heat rate varies with NOF, it is necessary to determine both the target and actual heat rates at the same NOF. This adjustment provides a common basis for comparison purposes and is shown numerically for each GPIF unit in columns 5 through 8. Column 9 contains the Generating Performance

Incentive Points as determined by interpolating from the tables shown on pages 8 through 19. These tables are based on the targets and target ranges approved by the Commission.

Q. Please explain the primary reason FPL will receive a reward under the GPIF for the January through December 2019 period.

A. The primary reason that FPL will receive a reward for the period is that adjusted actual EAFs for ten out of the twelve GPIF units were better than their targets. In addition, four out of the twelve GPIF units operated with an adjusted actual ANOHR that was below the ±75 Btu/kWh dead band.

Q. Please summarize each nuclear unit's performance as it relates to the EAF.

A. St. Lucie Unit 1 operated at an adjusted actual EAF of 71.2%, compared to its target of 84.6%. This results in -10.0 points, which corresponds to a GPIF penalty of $2,079,355.

St. Lucie Unit 2 operated at an adjusted actual EAF of 100.0%, compared to its target of 93.6%. This results in +10.0 points, which corresponds to a GPIF reward of $1,924,535.

Turkey Point Unit 3 operated at an adjusted actual EAF of 99.1% compared to its target of 93.6%. This results in +10.0 points, which corresponds to a GPIF reward of $1,798,297.

Turkey Point Unit 4 operated at an adjusted actual EAF of 87.6% compared to its target of 81.3%. This results in +10.0 points, which corresponds to a GPIF reward of $1,631,567.

In total, the nuclear units' EAF performance results in a GPIF reward of $3,275,044.

Q. Please summarize each nuclear unit's performance as it relates to ANOHR.

A. The St. Lucie Unit 1 adjusted actual ANOHR is 10,397 Btu/kWh compared to its target of 10,404 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

The St. Lucie Unit 2 adjusted actual ANOHR is 10,248 Btu/kWh compared to its target of 10,268 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

The Turkey Point Unit 3 adjusted actual ANOHR is 10,594 Btu/kWh compared to its target of 11,021 Btu/kWh. This ANOHR is better than the ±75 Btu/kWh dead band around the projected target. This results in +10.0 points, which corresponds to a GPIF reward of 335,841.

Turkey Point Unit 4 adjusted actual ANOHR is 10,942 Btu/kWh compared to its target of 10,954 Btu/kWh. This ANOHR is within the ±75 Btu/kWh dead band around the projected target; therefore, there is no GPIF reward or penalty.

In total, the nuclear units' heat rate performance results in a GPIF reward of $335,841.

Q. What is the total GPIF reward for FPL's nuclear units?

A. $3,610,885.

Q. Please summarize the performance of FPL's fossil units.

A. Regarding EAF performance, seven of the eight fossil generating units performed better than their availability targets as shown on Exhibit CRR-1, page 5, resulting in a combined reward of $2,908,955. The other one performed worse than its availability target as shown on Exhibit CRR-1, page 5, resulting in a penalty of $477,561. Thus, the total fossil units' EAF performance results in a net GPIF reward of $2,431,394.

Regarding ANOHR, four of the eight fossil units operated with ANOHRs that were within the ±75 Btu/kWh dead band so there were no incentive rewards or penalties. Another three operated below the dead band so they received a combined reward of $3,610,169 and one unit operated above the dead band so it received a penalty of $1,526,766. Thus, the total fossil units' heat rate performance results in a net GPIF reward of $2,083,403.

Q. What is the total GPIF reward/penalty for FPL's fossil units?

A. The net GPIF fossil availability performance reward of $2,431,394 plus the net GPIF heat rate fossil performance reward of $2,083,403 results in a total GPIF reward for FPL's fossil units of $4,514,797.

Q. To recap, what is the total GPIF result for the period January through December 2019?

A. The total GPIF result for the period January through December 2019 is $16,250,444 of fuel savings to FPL's customers as a result of the availability and efficiency of FPL's GPIF generating units, and a GPIF reward of $8,125,681.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF CHARLES R. ROTE

DOCKET NO. 20200001-EI

SEPTEMBER 3, 2020

Q. Please state your name and business address.

A. My name is Charles R. Rote, and my business address is 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company (FPL) as the Business Services Director in the Power Generation Division of FPL, where I am responsible for budgeting, forecasting, regulatory reporting and financial internal controls for FPL's fossil generating assets.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present FPL's generating unit equivalent availability factor (EAF) targets and average net operating heat rate (ANOHR) targets used in determining the Generating Performance Incentive Factor (GPIF) for the period January through December 2021.

Q. Have you prepared, or caused to have prepared under your direction, supervision, or control, any exhibits in this proceeding?

A. Yes, I am sponsoring Exhibit CRR-2. This Exhibit supports the development of the 2021 GPIF EAF and ANOHR targets. The first page of this exhibit is an index to its contents. All other pages are numbered according to the GPIF Manual as approved by the Commission.

Q. Please summarize the 2021 system targets for EAF and ANOHR for the units to be considered in establishing the GPIF for FPL.

A. For the period of January through December 2021, FPL projects a weighted system equivalent planned outage factor ("EPOF") of 6.3% and a weighted system equivalent unplanned outage factor ("EUOF") of 7.6%, which yield a weighted system EAF target of 86.1%. The targets for this period reflect planned refuelings for St. Lucie Units 1 and 2 and Turkey Point Unit 3. FPL also projects a weighted system ANOHR target of 7,290 Btu/kWh for the period January through December 2021. These targets represent fair and reasonable values. Therefore, FPL requests that the targets for these performance indicators be approved by the Commission.

Q. Have you established individual target levels of performance for the units to be considered in establishing the GPIF for FPL?

A. Yes, I have. Exhibit CRR-2, pages 6 and 7, contains the information summarizing the individual targets and ranges for EAF and ANOHR for each of the thirteen generating units that FPL proposes to be considered as GPIF units for the period January through December 2021. All of these targets have been derived utilizing the accepted methodologies adopted in the GPIF Manual.

Q. Please summarize FPL's methodology for determining EAF targets.

A. The GPIF Manual requires that the EAF target for each unit be determined as the difference between 100% and the sum of the EPOF and EUOF. The EPOF for each unit is determined by the duration and magnitude of the planned outage, if any, scheduled for the projected period. The EUOF is determined by the sum of the historical average equivalent forced outage factor and the historical equivalent maintenance outage factor. The EUOF is then adjusted to reflect recent or projected unit overhauls following the projection period.

Q. Please summarize FPL's methodology for determining ANOHR targets.

A. To develop the ANOHR targets, a set of curves that reflect historical ANOHR and unit net output factors are developed for each GPIF unit. The historical data is analyzed for any unusual operating conditions and changes in equipment that affect the predicted heat rate. A regression equation is calculated and a statistical analysis of the historical ANOHR variance with respect to the best fit curve is also performed to identify unusual observations. The resulting equation is used to project ANOHR for the unit using the net output factor from the production costing simulation program, GenTrader. This projected ANOHR value is then used in the GPIF tables and in the calculations to determine the possible fuel savings or losses due to improvements or degradations in heat rate performance. This process is consistent with the GPIF Manual.

Q. How did you select the units to be considered when establishing the GPIF for FPL?

A. In accordance with the GPIF Manual, the GPIF units selected are responsible for no less than 80% of the estimated system net generation. The estimated net generation for each unit is taken from the GenTrader model, which forms the basis for the projected levelized fuel cost recovery factor for the period. In this case, the thirteen units which FPL proposes to use for the period January through December

2021 represent the top 82.3% of the total forecasted system net generation for this period excluding the Okeechobee Clean Energy Center. This unit came into service in April 2019 and was excluded from the GPIF calculation because there is insufficient historical data to include it. Consistent with the GPIF Manual, this unit will be considered in the GPIF calculations once FPL has enough operating history to use in projecting future performance.

Q. Do FPL's 2021 EAF and ANOHR performance targets as shown on Exhibit CRR-2 represent reasonable levels of generation availability and efficiency?

A. Yes, they do.

Q. Does this conclude your testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Liz Fuentes was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchase Power Cost Recovery Clause with Generating Performance Incentive Factor	Docket No: 20200001-EI

DECLARATION OF LIZ FUENTES

1. My name is Liz Fuentes, and my business address is Florida Power & Light Company ("FPL"), 9250 West Flagler Street, Miami, Florida, 33174.

2. I graduated from the University of Florida in 1999 with a Bachelor of Science Degree in Accounting. That same year, I was employed by FPL. During my tenure at the Company, I have held various accounting and regulatory positions of increasing responsibility with the majority of my career focused in regulatory accounting and the calculation of revenue requirements. Specifically, I have provided accounting support in multiple FPL retail base rate filings and other regulatory dockets filed at the Florida Public Service Commission ("FPSC" or the "Commission") as well as the Federal Energy Regulatory Commission ("FERC"). My responsibilities have included the management of the accounting for FPL's cost recovery clauses and the preparation, review and filing of FPL's monthly Earnings Surveillance Reports ("ESR") at the FPSC. I am a Certified Public Accountant ("CPA") licensed in the Commonwealth of Virginia and am a member of the American Institute of CPAs. I have previously filed testimony before the Commission for FPL's Solar Base Rate Adjustments ("SoBRAs") related to the solar photovoltaic projects placed in service in 2018 and 2020 (Docket Nos. 20170001-EI and 20190001-EI) and request for approval of the Indiantown Transaction (Docket No. 160154-EI).

3. I am employed by FPL as Senior Director, Regulatory Accounting.

4. The purpose of my declaration is to provide the final jurisdictional revenue requirements for the 2018 SoBRA approved by the Commission in Order No. PSC-2018-0028-FOF-EI, Docket No. 20180001-EI, and placed into service during 2018 (the "2018 Project"). The final jurisdictional revenue requirement computation is based on actual capital costs for the 2018 Project as required by FPL's Stipulation and Settlement Agreement approved by the Commission in Order No. PSC-16-0560-AS-EI, Docket No. 160021-EI, issued on December 15, 2016 ("Settlement Agreement").

5. Paragraph 10(g) of the Settlement Agreement states the following:

"In the event that the actual capital expenditures are less than the projected costs used to develop the initial SoBRA factor, the lower figure shall be the basis for the full revenue requirements and a one-time credit will be made through the CCR Clause. In order to determine the amount of this credit, a revised SoBRA Factor will be computed using the same data and methodology incorporated in the initial SoBRA factor, with the exception that the actual capital expenditures will be used in lieu of the capital expenditures on which the Annualized Base Revenue Requirement was based."

6. As reflected on page 1 of Attachment LF-1, the final jurisdictional annualized revenue requirement associated with the 2018 SoBRA is $55.797 million.

7. The final revenue requirement computation for the 2018 SoBRA is based on the same inputs used for the initial 2018 SoBRA Factor included in my testimony filed on August 24, 2017, Docket No. 20170001-EI, and approved by this Commission in Order No. PSC-2018-0028-FOF-EI, except for capital costs. As reflected on page 2 of Attachment LF-1, the projected total per book capital costs of $442.585 million used in the initial 2018 SoBRA Factor were replaced with the actual total per book costs of $411.805 million, resulting in a decrease in revenue

requirements of $4.094 million from the initial 2018 SoBRA calculation. The refund calculation associated with this decrease in revenue requirements is discussed in FPL witness Edward Anderson's declaration.

8. Under penalties of perjury, I declare that I have read the foregoing declaration and that the facts stated in it are true to the best of my knowledge and belief.

Liz Fuentes

LIZ FUENTES

Date: 8/31/2020

(Whereupon, prefiled direct testimony of Edward J. Anderson was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchase Power Cost Recovery Clause and Generating Performance Incentive Factor	Docket No. 20200001-EI

DECLARATION OF EDWARD J. ANDERSON

1. My name is Edward J. Anderson, and my business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408. I have personal knowledge of the matters stated in this declaration.

2. I am employed by Florida Power & Light Company ("FPL" or the "Company") as Manager-Regulatory Rate Development.

3. I hold a Bachelor of Arts in Economics and Business, from the Virginia Military Institute. In November 2016, I joined FPL as Principal-Rate Development within the Company's Regulatory Affairs Organization, and assumed my current role in March 2018. Prior to joining FPL, I was employed by Dominion Energy for fourteen years. From 2003 to 2007, I worked within Dominion's Trading and Marketing Organization as a Business Operations Support Associate and Power Market Analyst. My responsibilities included Power Pool (PJM and NE-ISO) reconciliation, analysis, and trading support. In 2007, I was promoted to Hourly Trader where I was responsible for managing and optimizing the hourly operations of Dominion's merchant power plant assets in PJM and NE-ISO. From 2008 to 2016, I worked within Dominion's State Regulation Department as a senior level Regulatory Pricing Analyst and Regulatory Advisor. My responsibilities included providing support and analysis as they related to rate design for all base and rider regulatory filings, and I was the Company's rates witness for several generation adjustment and fuel rate proceedings.

4. The purpose of my declaration is to provide the revisions to FPL's Solar Base

Rate Adjustment ("SoBRA") Factor for true-up of the 2018 Project revenue requirement, the amount to be refunded through the Capacity Cost Recovery Clause ("CCRC"), and the corresponding prospective true-up rates to become effective January 1, 2021. If approved, the Company will submit revised tariff sheets reflecting the Commission-approved charges.

5. FPL is employing the identical mechanism employed to true-up the capital expenditures associated with the 2017 Solar Project, as well as the true-ups for Cape Canaveral, and the Port Everglades Energy Center.

6. As presented on page 1 of Attachment LF-1 to the Declaration of Liz Fuentes, the 2018 Project final jurisdictional annualized base revenue requirement based on the actual capital costs for the 2018 Project is $55.797 million.

7. Except for the revenue requirement associated with the actual capital costs, the revised 2018 SoBRA Factor is computed using the same data used in the computation of the initial 2018 SoBRA Factor. This data includes billed retail base revenues from the sales of electricity and unbilled retail base revenues in the amount of $6,518.299 million, as shown in the 2018 SoBRA Filing.

8. The revised 2018 SoBRA Factor using the updated revenue requirement of $55.797 million is 0.856%. The computation of this revised factor is provided in Attachment EJA-1, page 1 of 3.

9. Pursuant to the Settlement Agreement and consistent with the Initial SoBRA Filing, once the 2018 Solar Project actual capital costs are known, if the actual capital costs are less than the projected costs used to develop the initial 2018 SoBRA Factor, a one-time credit is to be made through the Capacity Clause. The difference between the cumulative base revenues that have been collected since the implementation of the initial 2018 SoBRA Factor on March 1, 2018 through December 31, 2020, and the cumulative base revenues that would have resulted

if the revised 2018 SoBRA Factor had been implemented on March 1, 2018 will be credited to customers through the CCRC with interest through December 31, 2020 at the 30-day commercial paper rate as specified in Rule 25-6.109. The amount of the refund with interest for the 2018 Solar Project since the project entered commercial service is $12.402 million and is shown in Attachment EJA-1, pages 2-3.

10. In accordance with Section 10(g) of the Settlement Agreement, base rates will also be adjusted to reflect the revised 2018 SoBRA Factor effective January 1, 2021 to account for this revision in jurisdictional revenue requirements going forward. Attachments EJA-2 through EJA-4 present the calculations and resulting rates for this change.

11. Attachment EJA-5 provides projected bill changes. The typical bill projections reflect proposed base and clause changes to become effective on January 1, 2021.

12. Under penalties of perjury, I declare that I have read the foregoing declaration and that the facts stated in it are true to the best of my knowledge and belief.

Edward J. Anderson

Date: 9/1/2020

(Whereupon, prefiled direct testimony of Curtis D. Young was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 20200001-EI
Fuel and Purchased Power Cost Recovery Clause
Direct Testimony of
Curtis Young
(2019 Final True-Up)
on behalf of
Florida Public Utilities Company

Q. Please state your name and business address.

A. Curtis Young, 1635 Meathe Road, West Palm Beach, Florida 33411.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company.

Q. Could you give a brief description of your background and business experience?

A. I am the Senior Regulatory Analyst for Florida Public Utilities Company. I have performed various accounting and analytical functions including regulatory filings, revenue reporting, account analysis, recovery rate reconciliations and earnings surveillance. I'm also involved in the preparation of special reports and schedules used internally by division managers for decision making projects. Additionally, I coordinate the gathering of data for the FPSC audits.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the calculation of the final remaining true-up amounts for the period January 2019 through December 2019.

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

A. Yes. Exhibit________ (CDY-1) consists of Schedules A, C1 and E1-B for the Consolidated Electric Division. These schedules were prepared from the records of the company.

Q. What has FPUC calculated as the final remaining true-up amounts for the period January 2019 through December 2019?

A. For the Consolidated Electric Division the final remaining true-up amount is an over recovery of $1,631,177.

Q. How was this amount calculated?

A. It is the difference between the actual end of period true-up amount for the January through December 2019 period and the total true-up amount to be collected or refunded during the January - December 2020 period.

Q. What was the actual end of period true-up amount for January - December 2019?

A. For the Consolidated Electric Division it was $303,275 under recovery.

Q. What was the Commission-approved amount to be collected or refunded during the January – December 2020 period?

A. A consolidated under-recovery of $1,934,452 to be collected.

Q. Does this conclude your direct testimony?

A. Yes, it does.

<u>BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION</u>

DOCKET NO. 20200001-EI: Fuel and purchased power cost recovery clause with generating performance incentive factor.

Direct Testimony of Curtis D. Young (Estimated/Actual)

<u>On Behalf of Florida Public Utilities Company</u>

Q. Please state your name and business address.

A. My name is Curtis D. Young. My business address is 1635 Meathe Drive, West Palm Beach, Florida 33411.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company")

Q. Describe briefly your education and relevant professional background.

A. I have a Bachelor of Business Administration Degree in Accounting from Pace University in New York City, New York. I am the Senior Regulatory Analyst for Florida Public Utilities Company. I have performed various accounting and analytical functions including regulatory filings, revenue reporting, account analysis, recovery rate reconciliations and earnings surveillance. I'm also involved in the preparation of special reports and schedules used internally by division managers for decision making projects. Additionally, I coordinate the gathering of data for the FPSC audits..

Q. Have you previously testified in this Docket?

A. Yes, I have.

Q. What is the purpose of your testimony at this time?

A. I will briefly describe the basis for the Company's computations made in preparation of the schedules being submitted in this docket.

Q. Which of the Staff's schedules is the Company providing in support of this filing?

A. I am attaching Schedules E1-A, E1-B, and E1-B1 as part of Exhibit CDY-2. Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period January 2020 – December 2020 based on 6 Months Actual and 6 Months Estimated data. I have also prepared Exhibit CDY-3, which is comprised of revised Schedules A-1, A-2, A-4, A-8, A-8a and A-9 for each month from January 2020 through June 2020. The purpose for the inclusion of these schedules will be addressed in my testimony.

Q. Were these schedules completed by you or under your direct supervision?

A. The schedules were completed under my direct supervision.

Q. What was the final remaining true-up amount for the period January 2019 – December 2019?

A. The final remaining true-up amount was an under-recovery of $2,017,896.

Q. What is the estimated true-up amount for the period January 2020 – December 2020?

A. The estimated true-up amount is an over-recovery of $1,252,729.

Q. What is the total true-up amount estimated to be collected, or refunded for the period January 2021 – December 2021?

A. At the end of December 2020, based on six months actual and six months estimated, the Company estimates it will under-recover $765,167 in purchased power costs, which will be collected from January 2021 – December 2021.

Q. Has the Company made any revisions to its 2020 estimated six month projection data?

A. Yes, we made changes to the estimated fuel costs since our original projection filing for 2020. Our "special costs" which consists primarily of consultant costs and legal fees have been running lower than anticipated throughout the first half of the year and are expected to decrease by approximately $55,000 for the remainder of the year. Therefore, we have updated our fuel costs to more accurately reflect current billing data from our contracted services.

Q. The beginning true-up balance from your Schedule E1-b differs from the amount that appeared in your Final True-Up Amount for 2019, please explain?

A. It was discovered that our monthly Fuel filing for December 2018 as well as the 2018 Final True-up filing had errors with regards to Fuel Revenues. In that fourth quarter, we were still in the midst of restoring services to our many customers impacted by damages resulting from Hurricane Michael. Part of this process entailed applying several adjusting transactions within our billing system. The Company did not bill its customers in the affected areas of the hurricane during the months of October and November. In December, a majority of the services had been restored and the Company resumed its billing processes. Subsequently, due to the suspension of billing for a specific area, adjustments were made to the billing system and accounting financials to correct any billing issues. Around the same time, the

Company also received Commission approval to apply a portion of its 2018 Tax Cuts and Jobs Act settlement to its fuel and purchased power cost under- recovery. In the course of preparing the monthly fuel filing for December 2018, some adjustments were not accurately reflected in the fuel revenues causing the true-up to be overstated. This finding was not immediately detected and the discrepancy carried forward in our reported fuel filings, which necessitated FPUC performing a thorough reconciliation to correct the fuel filings and determine the appropriate true-up balance.

Q. Is the $3,952,348 under-recovery that appears as your beginning true-up balance on your Schedule E1-b the correct final true-up-amount for 2019?

A. Yes.

Q. **How will this correction be implemented in this filing?**

A. I have prepared revised monthly Fuel true-up filing for each of the months from January 2020 to June 2020 in Exhibit CDY-3 of this filing to further illustrate the monthly computations of the 2020 true-up recoveries.

Q. **In previous years FPUC explored other opportunities to provide power supply for its customers. Has FPUC continued to explore other opportunities?**

A. Yes. FPUC is continuing to look into other sources of power supply that will provide low cost, resilient and reliable energy to customers.

Q. **Would you please discuss the opportunities FPUC has been investigating?**

A. Yes. FPUC is continuing to explore both Solar Photovoltaic (solar) and Combined Heat and Power (CHP) technologies with the goal of providing low cost, resilient and reliable energy to customers. Solar opportunities are being explored in both the Northeast and Northwest Divisions and are under consideration at this time. In our Northeast Division, significant effort has been focused on the development of a second CHP on Amelia Island. This project will be similar in size and operation to the existing Eight Flags Energy project that began commercial operation in 2016. Amelia Island Energy (AIE), as it will be named, will be located approximately one mile from Eight Flags Energy at a separate mill on Amelia Island. This CHP will provide electrical energy to the FPUC grid and thermal energy in the form of steam/hot water to the mill. Preliminary engineering has been completed, operating agreements have been developed and air permitting is underway at this time. AIE will provide low cost energy to our customers while improving the resiliency and reliability to the FPUC grid on Amelia Island.

Q. Has the Company incurred any costs during the preliminary stages of this project?

A. Yes, the Company has engaged the consulting firms of Pierpont and McLelland LLC and Sterling Energy Services LLC and well as the law firm of Gunster, Yoakley and Stewart PA for their experienced expertise in the aforementioned processes. To date, the Company has incurred approximately $46,000 in the consulting and legal fees linked to this project and roughly estimate to spend another $50,000 by year-end 2020.

Q. When do you anticipate construction to begin on the AIE facility?

A. FPUC plans to seek Commission approval, must execute operating agreements, and obtain finalized air permits prior to ordering major equipment for the project. The Company's current schedule anticipates finalizing these steps later in 2020 with major equipment items anticipated to be ordered in early 2021. Commercial operation should occur within 1.5 years of ordering the major equipment.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200001-EI: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

Second Revised 2021 Projection Testimony of Curtis D. Young

On Behalf of

Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is Curtis D. Young. My business address is 1635 Meathe Drive, West Palm Beach, FL 33411.

Q. By whom are you employed?

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company") as Senior Regulatory Analyst.

Q. Could you give a brief description of your background and business experience?

A. I have a Bachelor of Business Administration Degree in Accounting from Pace University in New York City, New York. I am the Senior Regulatory Analyst for Florida Public Utilities Company. I have performed various accounting and analytical functions including regulatory filings, revenue reporting, account analysis, recovery rate reconciliations and earnings surveillance. I'm also involved in the preparation of special reports and schedules used internally by division managers for decision making projects. Additionally, I coordinate the gathering of data for the FPSC audits.

Q. Have you previously testified in this Docket?

A. Yes, I have.

Q. What is the purpose of your second revised testimony at this time?

A. My testimony will establish the "true-up" collection amount, based on actual January 2019 through June 2020 data and projected July 2020 through December 2021 data to be collected or refunded during January 2021 – December 2021. My testimony will also summarize the computations that are contained in revised composite exhibit CDY-4 supporting the January through December 2021 projected levelized fuel adjustment factors for its consolidated electric divisions which now include the flow-through of the over-collection of interim rates as addressed in the Company's position to Issue 3A of the prehearing statements. Additionally, these factors include a refund to customers per the settlement agreement for the corporate state income tax savings approved in Docket No. 20200033-EI by Order No. PSC-2020-0083-PAA-EI, issued on March 20, 2020

Q. What is the monetary impact of the over-collected interim rates adjustment to your 2020 true-up balance?

A. The adjustment is a $1,026,484 over-recovery to the true-up balance. This amount is comprised of $890,966 interim base rates collected from our customers from January through September 2020 and an additional $135,246 is estimated to be collected for October 2020. Finally, we compute $272 accrued interest for the period September through December 2020.

Q. What is the monetary impact of the state tax savings refund adjustment to your 2020 true-up balance?

A. The adjustment is a $35,851 over-recovery to the true-up balance. This amount is comprised of the NOI annual tax savings impact of $35,825 state tax savings and $26 of computed accrued interest.

Q. Were the schedules filed by the Company completed by you or under your direct supervision?

A. Yes, they were completed by me.

Q. Is FPUC providing the required schedules with this filing?

A. Yes. Included with this filing are the Revised Consolidated Electric Schedules E1, E1A, E2, E7, E8, and E10. These schedules are included in my Second Revised Exhibit CDY-4, which is appended to my testimony. Also included with this filing are the Revised Schedules E1-A, E1-B and E1-B1 as Revised Exhibit CDY-2. Revised Schedule E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up and Interest Provision for the period January 2020 – December 2020 based on 6 Months Actual and 6 Months Estimated data.

Q. Did you include costs in addition to the costs specific to purchased fuel in the calculations of your true-up and projected amounts?

A. Yes, included with our fuel and purchased power costs are charges for contracted consultants and legal services that are directly fuel-related and appropriate for recovery in the fuel and purchased power clause.

FPUC engaged Sterling Energy Services, LLC. ("Sterling") Christensen Associates Energy, LLC ("Christensen"), Locke Lord, LLP ("Locke"), and Pierpont and McClelland ("Pierpont") for assistance in the development and enactment of projects/programs designed to reduce their purchased power rates to its customers. The associated legal and consulting costs, included in the rate calculation of the Company's 2021 Projection factors, were not included in expenses during the last FPUC consolidated electric base rate proceeding and are not being recovered through base rates.

Mr. Cutshaw addresses these project assignments more specifically in his testimony.

Q. Please explain how these costs were determined to be recoverable under the fuel and purchased power clause?

A. Consistent with the Commission's policy set forth in Order No. 14546, issued in Docket No. 850001-EI-B, on July 8, 1985, the other fuel related costs included in the fuel clause are directly related to purchased power, have not been recovered through base rates.

Specifically, consistent with item 10 of Order 14546, the costs the Company has included are fuel-related costs that were not anticipated or included in the cost levels used to establish the current base rates. Similar expenses paid to Christensen and Associates associated with the design for a Request for Proposals of purchased power costs, and the evaluation of those responses, were deemed appropriate for recovery by FPUC through the fuel and purchased power clause in Order No. PSC-05-1252-FOF-EI, Item II E, issued in Docket No. 050001-EI. Additionally, in more recent Docket Nos. 20150001-EI, 20160001-EI, 20170001-EI, 20180001-EI, 20190001-EI and 20200001-EI the Commission determined that many of the costs associated with the legal and consulting work incurred by the Company as fuel related, particularly those costs related to the purchase power agreement review and analysis, were recoverable under the fuel clause. As the Commission has recognized time and again, the Company simply does not have the internal resources to pursue projects and initiatives designed to produce purchased power savings without engaging outside assistance for project analytics and due diligence, as well as negotiation and contract development expertise. Likewise, the Company believes that the costs addressed herein are appropriate for recovery through the fuel clause.

Q. What are the final remaining true-up amounts for the period January – December 2019?

A. The final remaining consolidated true-up amount was an under-recovery of $2,017,896.

Q. What are the estimated true-up amounts for the period of January – December 2020?

A. There is an estimated consolidated over-recovery of **$2,315,064.**

Q. Please address the calculation of the total true-up amount to be

collected or refunded during the January - December 2021 year?

A. The Company has determined that at the end of December 2020, based on six months actual and six months estimated, we will have a consolidated electric **over-recovery of $297,168.**

Q. What will the total consolidated fuel adjustment factor, excluding demand cost recovery, be for the consolidated electric division for the period?

A. The total fuel adjustment factor as shown on line 43, Schedule E-1 is **4.540¢** per KWH.

Q. Please advise what a residential customer using 1,000 KWH will pay for the period January - December 2021 including base rates, conservation cost recovery factors, gross receipts tax and fuel adjustment factor and after application of a line loss multiplier.

A. As shown on consolidated Schedule E-10 in Revised Composite Exhibit Number CDY-4, a residential customer using 1,000 KWH will pay **$128.30**. This is a decrease of **$8.61** below the previous period.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of P. Mark Cutshaw was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200001-EI

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

2021 Projection Testimony of P. Mark Cutshaw

On Behalf of

Florida Public Utilities Company

Q. **Please state your name and business address.**

A. My name is P. Mark Cutshaw, 208 Wildlight Avenue, Yulee, Florida 32097.

Q. **By whom are you employed?**

A. I am employed by Florida Public Utilities Company ("FPUC" or "Company").

Q. **Could you give a brief description of your background and business experience?**

A. I graduated from Auburn University in 1982 with a B.S. in Electrical Engineering and began my career with Mississippi Power Company in June 1982. I spent 9 years with Mississippi Power Company and held positions of increasing responsibility that involved budgeting, as well as operations and maintenance activities at various Company locations. I joined FPUC in 1991 as Division Manager in our Northwest Florida Division and have since worked extensively in both the Northwest Florida and Northeast Florida Divisions. Since joining FPUC, my responsibilities have included all aspects of budgeting, customer service, operations and maintenance in both the Northeast and

Northwest Florida Divisions. My responsibilities also included involvement with Cost of Service Studies and Rate Design in other rate proceedings before the Commission as well as other regulatory issues. During 2019 I moved into my current role as Director, Generation and Pipeline Development.

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

A. Yes, I've provided testimony in a variety of Commission proceedings, including the Company's 2014 rate case, addressed in Docket No. 20140025-EI. Most recently, I provided written, pre-filed testimony in Docket No. 20190001-EI, the Commission's regular fuel cost recovery proceeding, and also provided both pre-filed and live testimony the prior year, in Docket No. 20180001-EI, the Commissions' regular fuel cost recovery. I have also been involved in and filed testimony in Docket No. 20191056 for the Limited Proceeding to Recover Incremental Storm Restoration Costs.

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

A. My direct testimony addresses several aspects of the purchased power cost for our FPUC electric customers. This includes activities to investigate the potential for reduced purchase power costs, execution/amendment of purchased power agreements with Gulf Power Company ("Gulf")/Florida Power & Light ("FPL"), Combined Heat and Power ("CHP")generation supply located on Amelia Island and investigation into the opportunities of energy provided from solar and battery installations.

Q. What new opportunities has the Company implemented with the intent of achieving energy resiliency and reducing costs for its customers in its consolidated electric divisions?

A. The Company regularly pursues opportunities to achieve energy resiliency and reduced purchased power costs for the benefit of our customers. During 2018, FPUC began by executing a transmission interconnection agreement and a new purchased power agreement with Florida Power & Light (FPL) for our Northeast Florida Division. During 2019, a purchased power agreement with Gulf/FPL for our Northwest Florida Division was executed along with an amendment of the existing FPL purchased power agreement for our Northeast Florida Division.

Q. What is the status of the existing purchase power agreements in place with Gulf Power and FPL?

A. The existing agreement for our Northwest Florida Division with Gulf/FPL became effective January 1, 2020 and will continue in effect through December 31, 2026 unless extended by FPUC. The existing agreement for our Northeast Florida Division with FPL which became effective January 1, 2018 was amended in 2019 to continue in effect through the December 31, 2026 unless extended by FPUC.

Q. Can you provide background on the new purchased power agreement with FPL for the Northwest Florida Division and the amendment of the purchased power agreement for the Northeast Florida Division that became effective January 1, 2020?

A. Yes. Informal solicitations occurred with four providers that were capable of providing wholesale power to the Northwest Florida Division delivery points located in Jackson, Calhoun and Liberty Counties. Additional consideration was given to the ability to combine agreements for the Northeast and Northwest Florida Divisions in order to provide additional flexibility, reduce cost and increased energy resiliency between divisions. Proposals were received from four parties and the evaluation and discussions began immediately thereafter. Based on the differences in the bids submitted, the evaluation required additional time for soliciting additional information to allow for further assessment. After the evaluation was completed, FPL was determined to be the most appropriate selection and additional negotiations were conducted in order to develop a comprehensive purchased power agreement covering both the Northwest and Northeast Florida Divisions. On August 12, 2019, the "Native Load Firm All Requirements Power and Energy Agreement" ("Agreement") for the Northwest Florida Division was executed by both parties with an effective date of January 1, 2020 and continuing in effect through December 31, 2026. Additionally, on August 12, 2019, the "First Amendment to the Native Load Firm All Requirements Power and Energy Agreement" ("Amendment") for the Northeast Florida Division was executed by both parties. The "Amendment" will have the effect of extending the existing agreement for the Northeast Florida Division through December 31, 2026. Both the "Agreement" and "Amendment" include a provision that will allow FPUC the sole right to extend the agreements through December 31, 2030.

Q. Are there other efforts underway to identify projects that will lead to lower cost energy for FPUC customers?

A. Yes. FPUC continues to work with consultants, as well as project developers, to identify new projects and opportunities that can lead to increased energy resiliency and reduced fuel costs for our customers. We also continue to analyze the feasibility of energy production and supply opportunities that have been on our planning horizon for some time and noted in prior fuel clause proceedings, namely additional Combined Heat and Power (CHP) projects, potential Solar Photovoltaic ("PV") projects and associated utility scale battery projects.

More specifically, Pierpont & McLelland has been engaged to perform analysis and provide consulting services for FPUC as it relates to the structuring of, and operation under, the Company's power purchase agreements with the purpose of identifying measures that will minimize cost increases and/or provide opportunities for cost reductions. Locke Lord is a law firm with particular expertise in the regulatory requirements of the Federal Energy Regulatory Commission. Attorneys with the firm have provided legal guidance and oversight regarding the contracts and regulatory requirements for generation and transmission-related issues for the Northeast Florida Division. The Company's in-house experience in these areas is limited; thus, without this outside assistance, the Company's ability to pursue potential purchased power savings opportunities would be limited, as would its ability to properly evaluate proposals to meet our generation and transmission needs and ensure compliance with federal regulatory requirements.

Sterling Energy and Christensen Associates have been involved to assist the Company in the most cost-effective means of incorporating additional energy sources, such as power available from certain industrial customers, including customers with Combined Heat and Power ("CHP") capability, to further reduce the overall purchased power impact to all FPUC customers. Christensen Associates also assisted the Company with analysis regarding the purchase power agreements.

Q. Can you provide additional information on these CHP projects?

A. Yes. The success of the Eight Flags project has sparked interest in other CHP opportunities on Amelia Island. When coupled with industrial expansion in the area and the ability to do so within the context of the "Agreement" and "Amendment" with FPL, the already quantifiable benefits of the existing project has piqued the interest of others to contemplate partnering with a new CHP-based project. Given that FPUC would again be the recipient of any power generated by such project, FPUC has been actively involved in the initial development and engineering of a new project located on Amelia Island. Significant efforts have continued to develop this CHP which, similar to Eight Flags, will be located on Amelia Island and will allow FPUC to provide additional reliability and resilience to its electricity supply for its customers on Amelia Island. This second CHP will provide competitively priced electricity for FPUC's customers while providing high pressure steam and hot water to a local industrial customer. Preliminary engineering, financial modeling, operating agreements and Florida Department of Environmental Protection permitting have been completed for this CHP unit. FPUC anticipates that work will continue on this project with the projected in-service date of second quarter of 2022.

Q. Can you provide additional information on the PV and battery projects you referenced above?

A. Yes. FPUC has completed the analysis related to smaller PV systems within the FPUC electric service territory. Based on the results from the analysis, the economic feasibility of smaller PV installations has been difficult to achieve due to many different factors. At this time, FPUC is investigating opportunities involving larger PV installations which have proved to be more economically feasible. Not only will this increase the renewable energy available to FPUC, the cost is expected to complement the overall purchased power portfolio which will provide additional benefits to FPUC customers. The "Agreement" and the "Amendment" have provisions that allow for the development of PV installations by FPUC and provides for the possibility of a partnership between the parties that would allow for the development of a PV project.

Additionally, exploration into the inclusion of battery storage capacity in conjunction with the PV installation is being considered. These projects have been difficult to justify economically at this point but are still under consideration by FPUC. Nonetheless, the potential benefits of the PV and battery projects under consideration will be continued.

Q. Does this include your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Richard L. Hume was inserted.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony
Richard L. Hume
Docket No. 20200001-EI
Date of Filing: March 2, 2020

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

A. My name is Richard Hume. My business address is 700 Universe Blvd Juno Beach, FL 33408. I am the Regulatory Issues Manager for Gulf Power Company (Gulf or the Company).

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

A. I graduated from the University of Florida in 1991 with a Bachelor of Science degree in Business Administration with a Finance Major and earned a Master of Business Administration degree with a Finance Concentration from the University of Florida in 1995. In 1998, I worked for NewEnergy Associates, (which became a subsidiary of Siemens Power Generation), a consulting firm that worked with Electric and Gas Utilities across the United States. During that time, I consulted in the area of financial forecasting budgeting as well as cost of service and rate forecasting. In 2007, I joined Oglethorpe Power and after a year was promoted to the position of Director of Financial Forecasting. In that position I was primarily responsible for the long range financial forecast and resource plan. In 2012, I joined Florida Power and Light managing a data analytics team. In that position part of what my team was responsible for was customer rate and bill impact analysis and worked in partnership with the Regulatory Affairs team. In 2019, I joined Gulf Power as the Regulatory Issues Manager where my current responsibilities include oversight of the Company's fuel and purchase power cost recovery clause, calculation of cost recovery factors and the related regulatory filing function of Gulf Power Company.

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

A. The purpose of my testimony is to present the final true-up amounts for the period January 2019 through December 2019 for both the Fuel and Purchased Power Cost Recovery Clause and the Capacity Cost Recovery Clause. I will summarize Gulf Power Company's fuel expenses, net power transaction expense, purchased power capacity costs, and certify that these expenses were properly incurred during the period January 2019 through December 2019. Lastly, I will present the actual benchmark level for the calendar year 2020 gains on non-separated wholesale energy sales eligible for a shareholder incentive and the amount of gains or losses from hedging settlements for the period January 2019 through December 2019.

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

A. Yes, I am sponsoring 2 exhibits. Exhibit 1 consists of 8 schedules and includes 2 schedules which relate to the fuel and purchased power cost recovery final true-up, 1 schedule that relates to Gulf's natural gas fuel hedging activities for 2019 and 5 schedules that relate to the capacity cost recovery final true-up. Exhibit 2 contains Schedules A-1 through A-9 and A-12 for the period December 2019, previously filed with the Florida Public Service Commission (FPSC or Commission).

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

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

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

I. FUEL

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

A. Schedules 1 and 2 of my Exhibit RLH-1 relate to the fuel and purchased power cost recovery true-up calculation for the period January 2019 through December 2019. These schedules compare twelve months of actual data to the actual/estimated true-up filed in last year's fuel docket which included six months of actual and six months of re-projected data. In addition, Fuel Cost Recovery Schedules A-1 through A-9 for December 2019 are incorporated herein as Exhibit RLH-2. The A-schedules compare twelve months of actual data to twelve months of projected data from a combination of the original 2019 fuel projection for the period January through June, and the 2019 estimated true-up re-projections for the period July through December.

Q. What is the final fuel and purchased power cost true-up amount related to the period January 2019 through December 2019 to be addressed through the fuel cost recovery factors in the period January 2021 through December 2021?

A. A net over-recovery amount of $8,868,596, to be returned to customers, was calculated as shown on Schedule 1 of my Exhibit RLH-1.

Q. How was this amount calculated?

A. The $8,868,596 is calculated on Schedule 1 of my Exhibit RLH-1 by taking the difference between the estimated and actual over/under-recovery amounts for the period January 2019 through December 2019. The estimated under-recovery amount was $5,178,904 as compared to the actual over-recovery amount of $3,689,691, resulting in an over-recovery of $8,868,596. The estimated true-up amount for this period was approved in FPSC Order No. PSC-2019-0484-FOF-EI, dated November 18, 2019.

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

A. Gulf Power experienced lower than estimated fuel and net power expense higher than estimated jurisdictional fuel clause revenue. These variances are discussed in more detail below and are summarized on Schedule 2 of my Exhibit RLH-1.

Fuel Clause Revenue

Q. Please explain the variance in Fuel Revenue Applicable for 2019.

A. Gulf Power's jurisdictional fuel revenue was $336,275,528 which was $6,692,460 or 2.03% above the actual / estimated.

Total Fuel and Net Power Transactions

Q. During the period January 2019 through December 2019, how did Gulf Power Company's recoverable total fuel and net power transaction expenses compare with the actual/estimated expenses?

A. Gulf's recoverable total fuel cost and net power transaction expense was $375,055,223 which is $1,229,583 or 0.33% below the estimated amount of $376,284,806. Actual fuel and net power transaction energy was 18,436,512 MWh compared to the estimated net energy of 20,047,202 MWh or 8.03% lower than the estimated amount. The lower total fuel and net power transactions expense is attributed to a lower quantity of fuel and net power transaction energy than projected for the period presented above. This information is summarized on Schedule 2 of my Exhibit RLH-1.

Total Fuel Cost of Generated Power

Q. During the period January 2019 through December 2019, how did Gulf Power Company's recoverable fuel cost of net generation compare with the actual/estimated expenses?

A. Gulf's recoverable fuel cost of system net generation was $249,555,444 or 8.67% below the estimated amount of $273,248,789. This information is summarized on Schedule 2 of my Exhibit RLH-1 and the table below provided the detail of the variance.

Fuel Variance	MMBTU		
	2019 Final True-Up	**2019 Actual / Estimated**	**Difference**
OIL - C.T.			
Total Dollar	$118,657	$135,743	(17,086)
Units	6,131	8,476	(2,345)
$ per Units	19.3537	16.0150	3.34
Variance Due to Consumption			(45,384)
Variance Due to Cost			28,299
Total Variance			(17,086)
GAS			
Total Dollar	$100,624,974	$102,628,377	(2,003,404)
Units	28,409,420	28,202,278	207,142
$ per Units	3.5420	3.6390	(0.10)
Variance Due to Consumption			733,688
Variance Due to Cost			(2,737,092)
Total Variance			(2,003,404)
COAL + GAS B.L. + OIL B.L.			
Total Dollar	$143,794,404	$164,371,808	(20,577,403)
Units	44,404,113	54,286,597	(9,882,484)
$ per Units	3.2383	3.0279	0.21
Variance Due to Consumption			(32,002,573)
Variance Due to Cost			11,425,169
Total Variance			(20,577,403)
Other Adjustments to Fuel Costs			
Total Variance			(1,095,452)
Total			
Total Variance Due to Consumption			(31,314,269)
Total Variance Due to Cost			8,716,376
Total Variance			(23,693,345)

Total Cost of Purchased Power

Q. During the period January 2019 through December 2019, how did Gulf Power Company's recoverable fuel cost of purchased power compare to actual/estimated cost?

A. Gulf's recoverable fuel cost of purchased power for the period was $202,815,639 or 0.11% below the estimated amount of $203,040,737. Total megawatt hours of purchased power were 7,087,293 MWh compared to the estimate of 7,116,310 MWh or 0.41% below estimates. The resulting average fuel cost of purchased power was 2.862 cents per kWh or 0.30% above the estimated amount of 2.853 cents per kWh. This information is from Schedule A-1, period-to-date, for the month of December 2019 included in my Exhibit RLH-2 and summarized on schedule 2 of Exhibit RLH-1.

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

A. The lower total fuel cost of purchased power is primarily due to lower MWH purchased by Gulf Power through purchased power agreements than estimated.

Power Sales

Q. During the period January 2019 through December 2019 how did Gulf Power Company's recoverable fuel cost of power sold compare with the actual/estimated costs?

A. Gulf's recoverable fuel cost of power sold for the period is $79,803,568 or 21.37% lower than the estimated amount of $101,489,520. The total quantity of power sales was 3,299,829 MWh compared to Gulf's estimated sales of 4,212,573 MWh, or 21.67% below estimates. The resulting average fuel cost of power sold was 2.418 cents per kWh or 0.38% above the estimated amount of 2.409 cents per kWh. The 2019 actual information is from Schedule A-1, period-to-date, for the month of December 2019 and summarized on Schedule 2 of RLH-1.

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

A. The lower actual fuel cost of power sold is primarily due to a lower quantity of generation available for non-territorial sales after meeting Gulf's territorial load.

Gains on Non-Separated Wholesale Energy Sales Benchmark

Q. Has the benchmark level for gains on non-separated wholesale energy sales eligible for a shareholder incentive been updated for actual 2019 gains?

A. Yes, the three year rolling average gain on economy sales, based entirely on actual data for calendar years 2017 through 2019 is calculated as follows:

Year	Actual Gain
2017	1,988,936
2018	589,410
2019	159,393
Three-Year Average	$ 912,580

Q. What is the actual threshold for 2020?

A. The actual threshold for 2020 is $912,580.

II. HEDGING

Q. Did Gulf's fuel hedging activity during 2019 follow Gulf Power's Risk Management Plan for Fuel Procurement?

A. Yes. As part of the Stipulation and Settlement Agreement, in Docket No. 20160186-EI, Gulf agreed to continue its existing moratorium for new natural gas financial hedges until January 1, 2021. Although Gulf did not enter into any new financial hedge contracts in 2019, hedges that settled in 2019 were entered into prior to the current moratorium on natural gas financial hedges and complied with previously approved Risk Management Plans.

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

A. Gulf Power hedged 5,560,000 MMBtu of natural gas based upon plant Smith 3 and the Central Alabama PPA combined Cycle unit projected burns in 2019 using financial instruments. This represents 9% of Gulf's 63,244,546 MMBtu of actual gas burn for these resources during the period. The total amount of natural gas burn by month for these resources is reported on Schedule 3 of Exhibit RLH-1.

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

A. Natural gas was hedged using financial swap contracts that were entered into prior to the current moratorium to fix the price of natural gas to a certain price. These swaps settled against the NYMEX Last Day Final Settlement price.

Q. What was the actual total cost (e.g., fees, commissions, option premiums, future gains and losses, swap settlements) associated with each type of hedging instrument for the period January 2019 through December 2019?

A. No fees, commissions, or premiums were paid by Gulf on the financial hedge transactions during this period. Gulf's 2019 hedging program activities for the period January through December 2019 resulted in a net hedge settlement cost of $7,178,070 as shown on line 2 of the December 2019 Schedule A-1, period-to-date of my Exhibit RLH-2.

III. PURCHASED POWER CAPACITY

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

A. Schedules 4, CCA-1, CCA-2, CCA-3, and CCA-4 of Exhibit RLH-1 relate to the purchased power capacity cost recovery true-up calculation for the period January 2019 through December 2019. Schedules CCA-1 and Schedule 4 summarize the calculation of the final true-up amount. Schedules CCA-2 through CCA-4 provides the monthly calculation of the actual over/under-recovery of purchased power capacity costs, monthly calculation of the interest provision and additional details related to purchased power capacity contracts which also appear on Lines 1 and 2 of Schedule CCA-2. In addition, Schedule A-12 of my Exhibit RLH-2 contains purchased power capacity cost information for the period January 2019 through December 2019.

Q. What is the final purchased power capacity cost true-up amount related to the period of January 2019 through December 2019 to be addressed in the period January 2021 through December 2021?

A. An over-recovery amount of $452,844 should be returned to customers through 2021 purchased power capacity clause rates as shown on Schedule CCA-1 of Exhibit RLH-1.

Q. How was this amount calculated?

A. The $452,844 was calculated by taking the difference between the estimated January 2019 through December 2019 under-recovery of $622,746 and the actual under-recovery of $169,902. This true up amount is also the sum of lines 11, 12, and 15 under column 1 of Schedule 4 of Exhibit RLH-1. The estimated true-up amount for this period was approved in FPSC Order No. PSC-2019-0484-FOF-EI dated November 18, 2019.

Additional details supporting the approved estimated true-up amount are included on Schedules CCE-1A and CCE-1B filed July 26, 2019.

Q. During the period January 2019 through December 2019, how did Gulf's actual total purchased power capacity costs and jurisdictional capacity clause revenue compare with the actual/estimated amounts?

A. The actual total capacity payments for the period January 2019 through December 2019, as shown on line 5 of Schedule 4 contained in my Exhibit RLH-1, was $77,628,374. Gulf’s total estimated net purchased power capacity cost for the same period was $77,449,608, as indicated on line 5 of Schedule CCE-1B the Exhibit CSB-3 filed July 26, 2019 in Docket No. 20190001-EI. The difference between the actual net capacity cost and the estimated net capacity cost for the recovery period is $178,766 or 0.23% more than the estimated amount. Jurisdictional capacity clause revenue for the period January 2019 through December 2019, as shown on line 10 of Schedule 4, was $75,254,563, or $604,571 higher than the estimate of

$74,649,992. Jurisdictional capacity clause revenue and expense variances were less than one percent for the period.

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

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 20200001-EI

Before me, the undersigned authority, personally appeared Richard L. Hume, who being first duly sworn, deposes and says that he is the Regulatory Issues Manager of Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge and belief. He is personally known to me.

Richard L. Hume

Richard L. Hume
Regulatory Issues Manager

Sworn to and subscribed before me by means of ✓ physical presence or ____ online notarization this 2nd day of March, 2020.

Melissa Darnes

Notary Public, State of Florida at Large

NOTARY PUBLIC STATE OF FLORIDA
MELISSA A DARNES
Commission # GG 366942
Expires December 17, 2023
Bonded Thru Budget Notary Services

Gulf Power

FUEL AND PURCHASED POWER CAPACITY

Witness: Richard L. Hume

Exhibit Index

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

GULF POWER COMPANY

TESTIMONY OF RICH L. HUME

DOCKET NO. 20200001-EI

JULY 27, 2020

Q. Please state your name and address.

A. My name is Richard Hume. My business address is Gulf Power Company, 700 Universe Boulevard, Juno Beach, FL 33408.

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

A. I am employed by Gulf Power Company ("Gulf" or "Gulf Power") as Manager of Regulatory Issues, in the Regulatory & State Governmental Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

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 actual/estimated true-up amounts for the Fuel Cost Recovery ("FCR") Clause and the Capacity Cost Recovery ("CCR") Clause for the period January 2020 through December 2020.

Q. Have you prepared or caused to be prepared under your direction, supervision or control any exhibits with your testimony?

A. Yes, various schedules are included in Exhibit RLH-3 and Exhibit RLH-4. Exhibit RLH-3 contains the FCR schedules and Exhibit RLH-4 contains the CCR schedules.

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

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

Q. Please describe the data that Gulf has used as a comparison when calculating the FCR and CCR actual/estimated true-up amounts presented in your testimony.

A. The FCR true-up calculation compares actual/estimated data consisting of actuals for January 2020 through June 2020 and revised estimates for July 2020 through December 2020 to the data reflected in Gulf's 2020 Mid-Course Correction for the period January 2020 through December 2020 filed on April 2, 2020. However, the CCR true-up calculation compares actual/estimated data consisting of actuals for January 2020 through June 2020 and revised estimates for July 2020 through December 2020 to the data reflected in Gulf's original projections for the period January 2020 through December 2020 filed on September 3, 2019.

Q. Please explain the calculation of the interest provision that is applicable to the FCR and CCR true-up amounts.

A. The calculation of the interest provision follows the methodology used in calculating the interest provision for all cost recovery clauses, as previously approved by this Commission. The interest provision is the result of multiplying the monthly average true-up amount for the twelve-month period by the monthly average interest rate. The average interest rate for the months reflecting actual data is developed using the AA financial 30-day rates as published on the Federal Reserve website on the first business day of the current month and the subsequent month divided by two. The average interest rate for the estimated months is the actual rate published on the first business day in July 2020, which reflects the interest rate from the last business day in June 2020.

FUEL COST RECOVERY CLAUSE

Q. What has Gulf calculated as the fuel cost recovery true-up factor to be applied in the period January 2020 through December 2020?

A. The fuel cost recovery true-up factor for this period is 0.0102 cents per kWh. As shown on Schedule E-1A, this calculation includes an estimated under-recovery for the January through December 2020 period of $9,968,285 and the 2019 final true-up over-recovery position of $8,868,596 (see Schedule 1 of Exhibit RLH-1 filed in this docket on March 2, 2020) resulting in an under-recovery of $1,099,690 for the period.

The 2020 estimated under-recovery of $9,968,285 includes a mid-course correction refund credit calculated on an estimated refund of $51.3 million. (see Schedule E-1A Attachment 1 page 1 of the Petition of Gulf Power Company for Mid-Course Correction filed on April 2, 2020). The 2020 year-end under-recovery estimate of $1,099,690 will be incorporated into Gulf's proposed 2021 fuel cost recovery factors.

Q. Have you provided a schedule showing the calculation of the FCR 2020 actual/estimated true-up by month?

A. Yes. Exhibit RLH-3, schedule E-1B shows the calculation of the FCR actual/estimated true-up by month for the period January 2020 through December 2020.

Q. Please explain the calculation of the FCR end-of-period net true-up and actual/estimated true-up amounts you are requesting this Commission to approve.

A. Exhibit RLH-3, schedule E-1B shows the calculation of the FCR end-of-period net true-up and actual/estimated true-up amounts. The 2020 end-of-period net true-up amount to be carried forward to the 2021 FCR factors is an under-recovery of $9,968,285 (schedule E1-B, line 9, column 15). This amount includes the under-recovery amount for the period of $10,006,166 reduced by interest due to customers of $37,882 (Exhibit RLH-3, schedule E-1B, lines 6 plus 7, column 15).

Q. Were these calculations made in accordance with the procedures previously approved in predecessors to this Docket?

A. Yes.

Q. Have you provided a schedule showing the variances between the actual/estimated amounts and the projections for 2019?

A. Yes. Exhibit RLH-3, schedule E-1B-1 provides a variance calculation that compares the 2020 actual/estimated period data by component to the same components from the 2020 mid-course correction filed on April 2, 2020.

Q. Please summarize the variance schedule E-1B-1 of Exhibit RLH-3.

A. Gulf's mid-course correction projected jurisdictional Total Fuel and Net Power Transaction costs to be $306.2 million for 2020 (Exhibit RLH-3, schedule E-1B-1, line 13, column 4). The 2020 actual/estimated jurisdictional Total Fuel and Net Power Transactions are now estimated to be $310.3 million (Exhibit RLH-3, schedule E-1B-1, line 13, column 3). The net impact to total jurisdictional fuel costs is $4.1M or 1.32% increase in fuel cost from the mid-course correction (Exhibit RLH-3, Schedule E1B1, line 21).

Q. Please explain the variances in jurisdictional total fuel costs and net power transactions.

A. The summary below shows the primary drivers for the $4.1 million variance in jurisdictional total fuel costs.

Description	Variance (millions)
Fuel Costs of System Net Generated	$ (20.8)
Other Generation Power	$ (1.1)
Total Cost of Purchased Power	$ (0.7)
Gain on Power Sales	$ 26.7
Total	**$ 4.1**

<u>Fuel Cost of System Net Generation: $20.8 million decrease (Exhibit RLH-3, schedule E-1B-1, line 1 column 5):</u>

The primary drivers for the decrease of System Net Generation are lower coal consumption and lower prices for gas. The table below outlines the variances in more detail and is also shown on schedule E3.

Fuel Variance by Major Fuel Type	2020 Actual Estimated	2020 Midcourse Correction	Variance
OIL - C.T.			
Total Dollar	$56,283	$15,523	$ 40,760
MMBTU	3,607	1,005	$ 2,602
$ per MMBTU	15.60	15.45	$ 0.15
		Variance Due to Consumption	$ 40,591
		Variance Due to Cost	$ 169
GAS			
Total Dollar	$115,892,747	$136,160,615	$ (20,267,868)
MMBTU	53,102,470	52,904,939	$ 197,531
$ per MMBTU	2.18	2.57	$ (0.39)
		Variance Due to Consumption	$ 430,618
		Variance Due to Cost	$ (20,698,486)
COAL + GAS B.L. + OIL B.L.			
Total Dollar	$96,188,953	$96,870,135	$ (681,182)
MMBTU	30,846,853	33,944,999	$ (3,098,146)
$ per MMBTU	3.12	2.85	$ 0.27
		Variance Due to Consumption	$ (9,666,216)
		Variance Due to Cost	$ 8,985,034
Other Adjustments to Fuel Costs			
Total Variance	894,494	860,835	$ 33,659
		Total Variance Due to Consumption	$ (9,195,007)
		Total Variance Due to Cost	$ (11,679,624)
		Total Variance	$ (20,874,632)

<u>Other generated power: $1.1 million decrease (Exhibit RLH-3, schedule E-1B-1, lines 1a,1b,2 and 3, column 5):</u>

Other costs of generated power variances are those related to hedging costs, other generation and miscellaneous adjustments to fuel costs.

<u>Total Cost of Purchased Power: $0.7 million decrease (Exhibit RLH-3, schedule E-1B-1, line 7, column 5):</u>

The variance for the Cost of Purchased Power is primarily attributed to a decrease in cost of other economy purchases offset by an increase in payments to qualified facilities. Additionally, as a result of lower cost energy available in the Southern Company Power Pool, Gulf is estimating an increase of 184,269 or 2.5% in MWH purchases. The actual/estimated costs of purchased power (cents / kWh) is 2.82%

lower than originally projected for those purchases. The actual/estimated cost of purchased power is 2.3964 cents per kWh which is 0.0695 lower than the original projected price per kWh of 2.4659 which is $703,267 or 0.39% lower than original projected.

Total Gains on Power Sales: $26.7 million increase (Exhibit RLH-3, schedule E-1B-1, line 12, column 5): The variance for Gains on Power sales is primarily attributed to 1,199,460 MWh or 20.44% lower than projected power sales. Gulf is also estimating a lower than projected reimbursement for these sales of 0.0811 cents per kWh or 4.25%. The lower sales and lower price per kWh results in $26.7 million or 23.82% lower sales credit to Gulf's customers.

CAPACITY COST RECOVERY CLAUSE

Q. Have you provided a schedule showing the calculation of the CCR 2020 actual/estimated true-up by month?

A. Yes. Exhibit RLH-4, schedule CCE-1A provides the calculation of the CCR actual/estimated true-up by month for the period January 2020 through December 2020.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2020 through December 2020?

A. The true-up for this period is 0.0209 cents per kWh, as shown on Schedule CCE-1A. This calculation includes an estimated under-recovery of $2,700,587 for January 2020 through December 2020. It also includes a final over-recovery of $452,844 for the period January 2019 through December 2019 (see Schedule

CCA-1 of Exhibit RLH-1 filed in this docket on March 2, 2020). The resulting total under-recovery of $2,247,743 will be incorporated into Gulf Power's proposed 2021 purchased power capacity cost recovery factors.

Q. **Please explain the calculation of the CCR 2019 actual/estimated true-up and the end-of-period net true-up amounts you are requesting this Commission to approve.**

A. Exhibit RLH-4, CCE-1B shows the actual/estimated capacity costs and applicable revenues (January 2020 through June 2020 reflects actual data, while the data for July 2020 through December 2020 is based on updated estimates) compared to the original projection filing for the January 2020 through December 2020 period. The $2,247,743 under-recovery is due to lower than projected retail sales. The total jurisdictional capacity payments are projected to be $502,053 or 0.6% lower than Gulf's original projection filing.

Description	2020 Actual Estimated	2020 Projection	Variance
Total Jurisdictional Capacity Payments	$82,984,719	$83,486,772	($502,053)

Q. **Is this true-up calculation made in accordance with the procedures previously approved in predecessors to this docket?**

A. Yes.

Q. **Does this conclude your testimony?**

A. Yes, it does.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 20200001-EI

Before me, the undersigned authority, personally appeared Richard L. Hume, who being first duly sworn, deposes and says that he is the Regulatory Issues Manager of Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge and belief. He is personally known to me.

Richard L. Hume
Regulatory Issues Manager

Sworn to and subscribed before me by means of ✓ physical presence or ____ online notarization this 27th day of July, 2020.

Melissa Darnes
Notary Public, State of Florida at Large

NOTARY PUBLIC STATE OF FLORIDA
MELISSA A DARNES
Commission # GG 366942
Expires December 17, 2023
Bonded Thru Budget Notary Services

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

GULF POWER COMPANY

TESTIMONY OF RICHRD L. HUME

DOCKET NO. 20200001-EI

SEPTEMBER 3, 2020

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

A. My name is Richard Hume. My business address is Gulf Power Company ("Gulf"), One Energy Place Pensacola, FL 32520.

Q. Have you previously filed testimony in this docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the projection of fuel expenses, net power transaction expenses, and purchased power capacity costs for the period January 2021 through December 2021 for which Gulf seeks recovery through the Fuel Cost Recovery ("FCR") Clause. I will also present the calculation of Gulf's Capacity Cost Recovery ("CCR") factors for the period January 2021 through December 2021.

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

A. Yes, I have. They are as follows:

Exhibit Number	Summary
Exhibit RLH-5	23 schedules related to Fuel and Capacity Calculations

Exhibit Number	Summary
Exhibit RLH-6	Gulf's Hedging Information Report filed with the Commission Clerk on April 3, 2020, and assigned Document Numbers DN 01746-2020 (redacted) and 01752-2020 (confidential information). This exhibit details Gulf's natural gas hedging transactions for August 2019 through December 2019 in compliance with Order No. PSC-08-0316-PAA-EI.
Exhibit RLH-7	Gulf's Hedging Information Report filed with the Commission Clerk on August 10, 2020, and assigned Document Numbers DN 0431-2020 (redacted) and DN 04308-2020 (confidential information). This exhibit details Gulf's natural gas hedging transactions for January 2020 through March 2020 in compliance with Order No. PSC-08-0316-PAA-EI.
Exhibit RLH-8	Calculation of the stratified separation factors.

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

A. Yes, I have.

FUEL COST RECOVERY CLAUSE

Q. Please explain the calculation of the fuel and purchased power expense true-up amount included in the annual fuel factor for the period January 2021 through December 2021.

A. The 2021 FCR factors includes an adjustment to the total net true-up, for the Generating Performance Incentive Factor ("GPIF"). As shown on Schedule E-1A of Exhibit RLH-5, the total true-up amount is a $1,099,690 under-recovery for the period January 2020 through December 2020. The estimated under-recovery includes six months of actual data and six months of estimated data as reflected on Schedule E-1B of Exhibit RLH-5.

The GPIF result shown on Line 26 of Schedule E-1 is an increase of 0.0006 cents per kWh to the annual fuel factor. This amount represents an increase in the amount of $62,232 as shown in Exhibit JAV-1 of Witness Van Norman's testimony filed on March 16, 2020.

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

A. A revenue tax factor of 1.00072 has been applied to all jurisdictional fuel costs, as shown on Line 24 of Schedule E-1.

Q. What is the annual projected fuel factor for the period January 2021 through December 2021?

A. Gulf has proposed an annual fuel factor of 3.053 cents per kWh. This factor is based on projected fuel and purchased power energy expenses and projected kWh sales for January 2021 through December 2021 and includes the true-up and GPIF amounts identified above.

Q. How were the line loss multipliers used on Schedule E-1E calculated?

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

Q. What fuel factor does Gulf propose for its largest group of customers (Group A), those on Rate Schedules RS, GS, GSD, and OS-III?

A. Gulf proposes a standard fuel factor, adjusted for line losses, of 3.070 cents per kWh for Group A. Fuel factors for Groups A, B, C, and D are shown on Schedule E-1E. These factors have all been adjusted for line losses.

Q. How were the time-of-use fuel factors calculated?

A. The time-of-use fuel factors were calculated based on seasonal on and off-peak projected loads for the period January 2021 through December 2021 and include the GPIF and true-up amount. These time-of-use fuel factors as shown on Schedule E-1E have all been adjusted for line losses.

Q. How does the proposed fuel factor for Rate Schedule RS compare with the factor applicable to December 2020, and how would the change affect the cost of 1,000 kWh on Gulf's residential rate RS?

A. The current 2020 fuel factor for Rate Schedule RS applicable through December 2020 is 3.262 cents per kWh compared with the proposed factor of 3.070 cents per kWh. For a residential customer who is billed for 1,000 kWh in January 2021, the fuel portion of the bill would decrease from $32.62 to $30.70 or a 5.9% decrease.

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

A. Yes. A tabulation of these costs is set forth in Schedule E-11 of my exhibit. These costs represent the estimated averages for the period January 2021 through December 2021. In addition, pursuant to Commission Order No. PSC-16-0119-TRF-EG in Docket No. 150248-EG, Gulf has calculated what the bill credit would be if it launched the Community Solar Pilot Program described in that Order. The bill credit would be $1.68 per month based on the 2021 projected solar-weighted average annual avoided energy cost is 2.7 cents per kWh for the period January 2021 and December 2021.

Q. What amount have you calculated to be the appropriate benchmark level for calendar year 2020 gains on non-separated wholesale energy sales eligible for a shareholder incentive?

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

2018 actual gains	589,410
2019 actual gains	159,393
2020 estimated gains	74,883
Three-Year Average	$274,562

This amount represents the minimum projected threshold for 2021 that must be achieved before shareholders may receive any incentive.

FUEL PROCUREMENT

Q. Please describe Gulf's fuel procurement program for the 2021 projected period?

A. Gulf's coal requirements are purchased in the market through the Request for Proposal (RFP) process that has been used for many years. Natural gas supply will be purchased from multiple suppliers using a combination of firm quantity agreements with market-based pricing for baseload needs and daily spot market purchases. Natural gas transportation will be secured using a combination of firm and spot transportation agreements.

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

A. Gulf procures natural gas using both long and short-term agreements for gas supply at market-based prices. Gulf secures gas transportation using a combination of long-term agreements for firm pipeline capacity and released capacity, delivered natural gas, and interruptible transportation for shorter term needs.

HEDGING

Q. Has anything changed with regard to the status of Gulf's hedging program since filing testimony on July 27, 2020, in this docket?

A. There has been no change in the status of Gulf's hedging program. Gulf's fuel hedging program was terminated pursuant to the Stipulation and Settlement Agreement approved by this Commission in Order No. PSC-17-0178-S-EI. Gulf's hedge positions that were put in place prior to terminating all hedging activities ended as of March 2020. Accordingly, actual hedging settlement data is included in my Exhibit RLH-6 as previously filed with this Commission on August 10, 2020. Gulf has no further hedging activity to report past March 2020.

Q. What were the results of Gulf's natural gas price hedging program for the period August 2019 through March 2020?

A. Gulf had financial hedges in place during the August 2019 through March 2020 period to hedge the price of natural gas. These financial hedges were effective in delivering greater price certainty for a portion of Gulf's natural gas requirements during that time period. Between August 2019 and July 2020, Gulf recorded hedging settlement costs of $5,154,160. Pursuant to Order No. PSC-08-0316-PAA-EI, Gulf filed Hedging Information Reports with the Commission on April 3, 2020, and August 10, 2020, detailing its natural gas hedging transactions for August 2019 through March 2020. I am sponsoring these reports as Exhibits RLH-6 and RLH-7 to my testimony in this docket.

CAPACITY COST RECOVERY CLAUSE

Q. You stated earlier that you are responsible for the calculation of the Capacity Cost Recovery factors. Which of your exhibits relate to the calculation of these factors?

A. Schedule CCE-1, including CCE-1A and CCE-1B, Schedule CCE-2, and Schedule CCE-4 of my Exhibit RLH-5 relate to the calculation of the CCR recovery factors for the period January 2021 through December 2021.

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

A. Schedule CCE-1 provides the calculation of stratified jurisdictional capacity costs to be recovered through the CCR. The schedule provides Gulf's total projected net capacity expense, which includes a credit for transmission revenue. The total net projected capacity costs are applied to a stratified jurisdictional factor and added to the total true-up which is then adjusted for revenue taxes to determine the amount to be recovered in the period through CCR recovery factors.

The total recoverable capacity payments for the period are $85,862,394. This amount is captured in the Schedule CCE-1, line 20. Schedule CCE-4 shows the projected cost associated with the Southern Intercompany Interchange capacity, if applicable, and any long-term purchased power contracts that are included for capacity cost recovery and lists their associated capacity amounts in megawatts. Also included in Gulf's 2021 projection of capacity cost is revenue produced by a market-based agreement between the Southern electric system operating companies and South Carolina PSA (Public Service Authority). The total capacity cost of $85,691,528 is shown on Schedule CCE-4, line 11.

Gulf has included an estimate of transmission revenues associated with off-system economy sales in the amount of $84,000 in its capacity cost recovery projection. This amount is captured on Schedule CCE-1, line 6 of my Exhibit RLH-5.

Q. What jurisdictional factor was used to calculate projected recoverable capacity costs for the period January 2021 through December 2021?

A. The calculations of the separation factors are provided in Exhibit RLH-8. Gulf has separated the production-related capacity costs based on stratified separation factors that better reflect the types of generation required to serve load under stratified wholesale power sales contracts. The use of stratified separation factors thus results in a more accurate separation of capacity costs between the retail and wholesale jurisdictions.

Gulf has one stratified wholesale power sales contract effective as of January 1, 2020, with Florida Public Utility. The separation factors for the intermediate and peaking strata associated with this contract was calculated in a manner consistent with the method used by Florida Power & Light Company and Duke Energy Florida using Gulf's 2018 Cost of Service Load Research Study filed with this Commission in accordance with Rule 25-6.0437, F.A.C.

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

A. A revenue tax factor of 1.00072 has been applied to all jurisdictional capacity costs, as shown on Line 19 of Schedule CCE-1.

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

A. As required by Commission Order No. 25773 in Docket No. 910794-EQ, the revenue requirements have been allocated using the cost of service methodology approved by the Commission in Order No. PSC-17-0178-S-EI in consolidated Docket Nos. 160186-EI and 160170-EI. This allocation is consistent with the treatment accorded to production plant in the cost of service study approved by the Commission in Gulf's most recent base rate proceeding. For purposes of the CCR Clause, Gulf has allocated the net capacity costs by rate class within the retail jurisdiction based on the 12-Monthly Coincident Peak (MCP) and 1/13th method described below.

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

A. The rate class demand allocation factors used in the CCR Clause has been calculated using the 2018 Cost of Service Load Research Study results filed with the Commission in accordance with Rule 25-6.0437, F.A.C. and adjusted for losses. The rate class energy allocation factors were calculated based on projected kWh sales for the period and adjusted for losses. The calculations of the allocation factors are shown in columns A through I on page 1 of schedule CCE-2.

Q. Please describe the calculation of the CCR recovery factors by rate class used to recover capacity costs.

A. The CCR recovery factors by rate class are calculated by dividing the revenue requirement assigned to each rate class by the classes' billing determinants. The revenue requirements are assigned to each rate class as shown in columns A through D on page 2 of Schedule CCE-2 based on the 12-MCP and 1/13th method, whereby 12/13ths of the jurisdictional capacity costs to be recovered is allocated by rate class based on the demand allocator and 1/13th is allocated based on the energy allocator.

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

For all other rate classes, the total revenue requirement assigned to each rate class shown in column E is divided by that class's projected kWh sales for the twelve-month period to calculate the CCR recovery factor. This factor would be applied to each customer's total kWh sales to calculate the amount to be billed each month.

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

A. The capacity costs recovered through the clause for a residential customer who is billed for 1,000 kWh the capacity charge would increase from $8.78 to $9.15 or 4.2%.

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

A. No.

Q. When does Gulf propose to collect these new FCR charges and CCR charges?

A. Gulf proposes that the FCR factors and CCR factors for the period January 2021 through December 2021 become effective starting with the first meter readings made on or after January 1, 2021. These factors should remain in effect until modified by the Commission.

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

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 20200001-EI

Before me, the undersigned authority, personally appeared Richard L. Hume, who being first duly sworn, deposes and says that he is the Regulatory Issues Manager of Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge and belief. He is personally known to me.

Richard L. Hume
Richard L. Hume
Regulatory Issues Manager

Sworn to and subscribed before me by means of ✓ physical presence or ____ online notarization this 2nd day of September, 2020.

Melissa Darnes
Notary Public, State of Florida at Large

NOTARY PUBLIC STATE OF FLORIDA
MELISSA A DARNES
Commission # GG 366942
Expires December 17, 2023
Bonded Thru Budget Notary Services

(Whereupon, prefiled direct testimony of Jarvis Van Norman adopted by Charles Rote and the prefiled direct testimony of Charles Rote was inserted.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony
J. A. Van Norman
Docket No. 20200001-EI
Date of Filing: March 16, 2020

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

A. My name is Jarvis A. Van Norman. My business address is One Energy Place, Pensacola, Florida 32520-0335. My current job position is Budget Supervisor of Power Generation for Gulf Power Company.

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

A. I received my Bachelor of Science degree in Business Administration from the University of Southern Mississippi in 1987. I joined Gulf Power in 1985 as a coop student in the Accounting organization. After graduating in December 1987, I joined Gulf Power in 1988 and worked three years in Customer Accounting. I transferred throughout Gulf Power's Accounting organization through the years with increased responsibilities. In 2006, I transferred to Southern Company Services where I was the Admin Lead on Gulf Power's scrubber project at Plant Crist. In 2010, I transferred back to Gulf Power in Property Accounting where I performed Gulf Power's Depreciation Study. In 2014, I was promoted to Budget Supervisor of External Affairs and Corporate Services until 2018 when I was promoted to Budget Supervisor of Power Generation. My current responsibilities include oversight of Power Generation's O&M and capital budgets and preparing all Generating

Performance Incentive Factor (GPIF) filings as well as other generating plant reliability and heat rate performance reporting for Gulf Power Company.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present GPIF results for Gulf Power Company for the period of January 1, 2019, through December 31, 2019.

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

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

Counsel: We ask that Mr. Van Norman's Exhibit consisting of five schedules be marked as Exhibit No. _______ (JAV-1).

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

A. Yes. Some corrections have been made to the actual unit performance data, which was submitted monthly to the Commission during this time period. These corrections are based on discoveries made during the final data review to ensure the accuracy of the information reported in this filing. The actual unit performance data tables on pages 13 through 22 of Schedule 5 of exhibit JAV-1 incorporate these changes. The data contained in these tables is the data upon which the GPIF calculations were made.

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

A. Actual equivalent availability and adjusted actual equivalent availability figures for each of the Company's GPIF units are shown on page 12 of Schedule 5. Pages 3 through 7 of Schedule 2 contain the calculations for the adjusted actual equivalent availabilities.

A calculation of GPIF availability points based on these availabilities and the targets established by FPSC Order No. PSC-2018-0610-FOF-EI is on page 8 of Schedule 2. The results are: Scherer 3, 10.00 points; Crist 7, 0.00 points; Daniel 1, 0.00 points; Daniel 2, 0.00 points; and Smith 3, 10.00 points.

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

A. The detailed calculations of the actual average net operating heat rates for the Company's GPIF units are on pages 2 through 6 of Schedule 3. As was done for the prior GPIF periods, and as indicated on pages 7 through 11 of Schedule 3, the target equations were used to adjust actual results to the target basis. These equations, submitted in August 2018, are shown on page 13 of Schedule 3. As calculated on page 14 of Schedule 3, the adjusted actual average net operating heat rates correspond to the following GPIF unit heat rate points:

Scherer 3, -0.45 points; Crist 7, 0.00 points; Daniel 1, 0.00 points; Daniel 2, 8.76 points, and Smith 3, 0.00 points.

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

A. Using the unit equivalent availability and heat rate points previously mentioned, along with the appropriate weighting factors, the number of Company points achieved was 0.1 as indicated on page 2 of Schedule 4. This calculated to a reward in the amount of $62,232.

Q. Please summarize your testimony.

A. In view of the adjusted actual equivalent availabilities, as shown on page 8 of Schedule 2, and the adjusted actual average net operating heat rates achieved, as shown on page 14 of Schedule 3, evidencing the Company's performance for the period, Gulf calculates a reward in the amount of $62,232 as provided by the GPIF methodology.

Q. Does this conclude your testimony?

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 20200001-EI

Before me, the undersigned authority, personally appeared Jarvis Van Norman, who being first duly sworn, deposes and says that he is the Budget Supervisor of Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge and belief. He is personally known to me.

Jarvis Van Norman

Jarvis Van Norman
Budget Supervisor

Sworn to and subscribed before me by means of ✓ physical presence or ____ online notarization this 16th day of March, 2020.

Melissa Darnes

Notary Public, State of Florida at Large

NOTARY PUBLIC STATE OF FLORIDA

MELISSA A DARNES
Commission # GG 366942
Expires December 17, 2023
Bonded Thru Budget Notary Services

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

GULF POWER COMPANY

DIRECT TESTIMONY OF C.R. ROTE

DOCKET NO. 20200001-EI

SEPTEMBER 3, 2020

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

A. My name is Charles R. Rote. My business address is 700 Universe Boulevard, Juno Beach, Florida 33408. My current job position is Business Services Director in the Power Generation Division of FPL.

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

A. The purpose of my testimony is to present GPIF targets for Gulf Power Company for the period of January 1, 2021 through December 31, 2021.

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

A. Yes. I have prepared one exhibit entitled CR-1 consisting of three schedules.

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

A. Yes, it was.

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

A. We propose that Crist Unit 7, Daniel Units 1 and 2, Smith Unit 3, and Scherer Unit 3 be included as the Company's GPIF units. The projected net generation from these units is approximately 89% of Gulf's projected net generation for 2021.

Q. For these units, what are the target heat rates Gulf proposes to use in the GPIF for these units for the performance period January 1, 2021 through December 31, 2021?

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

Q. How were these proposed target heat rates determined?

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

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

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

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

A. Yes.

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

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

Q. How were the target equivalent availabilities determined?

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

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

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

Q. Mr. Rote, has Gulf completed the GPIF minimum filing requirements data package?

A. Yes, we have completed the minimum filing requirements data package. Schedule 3 of my exhibit contains this information.

Q. Mr. Rote, would you please summarize the targets that you are proposing?

A. Yes. Gulf asks that the Commission accept:

1. Crist Unit 7, Daniel Units 1 and 2, Smith Unit 3, and Scherer Unit 3 for inclusion under the GPIF for the period of January 1, 2021 through December 31, 2021.

2. The target, maximum attainable, and minimum attainable average net operating heat rates, as proposed by the Company and as shown on page 26 of Schedule 1 and on page 5 of Schedule 3 of my exhibit.

3. The target, maximum attainable and minimum attainable equivalent

availabilities, as proposed by the Company and as shown on page 4 of Schedule 2 and on page 5 of Schedule 3 of my exhibit.

4. The weekly average net operating heat rate least squares regression equations, shown on page 2 of Schedule 1 and on pages 17 through 26 of Schedule 3 of my exhibit, for use in adjusting the annual actual unit heat rates to target conditions.

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

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 20200001-EI

Before me, the undersigned authority, personally appeared Charles Rote, who being first duly sworn, deposes and says that he is the Power Generation Division Director Business Services of Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge and belief. He is personally known to me.

Charles Rote

Charles Rote
Power Generation Division Director Business Svcs

Sworn to and subscribed before me by means of ✓ physical presence or ____ online notarization this 1st day of September, 2020.

Notary Public State of Florida
Kristen Carey
My Commission HH 026570
Expires 08/02/2024

K Carey

Notary Public, State of Florida at Large

(Whereupon, prefiled direct testimony of M. Ashley Sizemore was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

M. ASHLEY SIZEMORE

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

A. My name is M. Ashley Sizemore. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "Company") in the position of Manager, Rates in the Regulatory Affairs department.

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

A. I received a Bachelor of Arts degree in Political Science and a Master of Business Administration from the University of South Florida in 2005 and 2008, respectively. I joined Tampa Electric in 2010 as a Customer Service Professional. In 2011, I joined the Regulatory Affairs Department as a Rate Analyst. I spent six years in the Regulatory Affairs Department working on environmental and fuel and capacity cost recovery clauses. During the last three years as a Program Manager in Customer Experience, I managed billing and payment customer solutions, products and services. I returned to the Regulatory Affairs Department in 2020 as Manager, Rates. My duties entail managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and approved environmental projects. I have ten years of electric utility experience in the areas of customer experience and project management as well as the management of fuel clause and purchased power, capacity, and environmental cost recovery clauses.

Q. Other than describing your background and qualifications, is the remainder of your testimony the same as that set forth in the testimony of Ms. Rusk filed March 2, 2020.

A. Yes, it is.

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 2019 through December 2019 for the Fuel and Purchased Power Cost Recovery Clause (“Fuel Clause”) and the Capacity Cost Recovery Clause

("Capacity Clause"), as well as the Optimization Mechanism gain sharing allocation for the period.

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. MAS-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 2019 through December 2019?

A. The final true-up amount for the Capacity Clause for the period January 2019 through December 2019 is an over–recovery of $111,228.

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 2019 Through December 2019", provides the calculation for the final over–recovery of $111,228. The actual capacity cost under-recovery, including interest, was $2,067,989 for the period January 2019 through December 2019 as identified in Document No. 1, pages 1 and 2 of 4. This amount, less the $2,179,217 actual/estimated under-recovery approved in Order No. PSC-2019-0484-FOF-EI issued November 18, 2019 in Docket No. 20190001-EI, results in a final over-recovery of $111,228 for the period, as identified in Document No. 1, page 4 of 4. This amount will be applied to the calculation of the capacity cost recovery factors for the period January 2021 through December 2021.

Q. What is the estimated effect of this $111,228 over-recovery for the January 2019 through December 2019 period on residential bills during the January 2021 through

December 2021 period?

A. The $111,228 over-recovery will decrease a 1,000 kWh residential bill by approximately $0.01.

Fuel and Purchased Power Cost Recovery Clause

Q. What is the final true-up amount for the Fuel Clause for the period January 2019 through December 2019?

A. The final Fuel Clause true-up for the period January 2019 through December 2019 is an over-recovery of $35,821,098. The actual fuel cost over-recovery, including interest, was $5,079,072 for the period January 2019 through December 2019. This $5,079,072 amount, plus the $30,742,026 projected under-recovery amount approved in Order No. PSC-2019-0484-FOF-EI, issued November 18, 2019 in Docket No. 20190001-EI, results in a net over-recovery amount for the period of $35,821,098.

Q. What is the estimated effect of the $35,821,098 over-recovery for the January 2019 through December 2019 period on residential bills during the January 2021 through December 2021 period?

A. The $35,821,098 over-recovery will decrease a 1,000 kWh residential bill by approximately $1.84.

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 2019 Through December 2019." It shows the calculation of the final fuel over-recovery of $35,821,098.

Line 1 shows the total company fuel costs of $574,069,880 for the period January 2019 through December 2019. The jurisdictional amount of total fuel costs is $574,069,880, 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 $9,140,612 over-recovered fuel costs for the period, adjustments, interest, true-up collected, and the prior period true-up shown on lines 5 through 8 respectively, constitute the actual over-recovery amount of $5,079,072 shown on line 9. The $5,079,072 actual over-recovery amount plus the $30,742,026 projected under-recovery amount shown on line 10, results in a final over-recovery amount of $35,821,098 for the period January 2019 through

December 2019, 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 2019 Through December 2019." It shows the calculation of the actual over-recovery compared to the estimated under-recovery for the same period.

Q. What was the total fuel and net power transaction cost variance for the period January 2019 through December 2019?

A. As shown on line A7 of Document No. 3, the fuel and net power transaction cost is $39,316,715 less than the amount originally estimated.

Q. What was the variance in jurisdictional fuel revenues for the period January 2019 through December 2019?

A. As shown on line C3 of Document No. 3, the company collected $9,052,449, or 1.6 percent greater jurisdictional fuel revenues than originally estimated.

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

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

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

A. Document No. 5 provides the capital costs and fuel savings for the Big Bend Units 1-4 ignition conversion projects for the period January 2019 through December 2019. This document also contains the capital structure components and cost rates relied upon to calculate the revenue requirements rate of return on capital projects recovered through the fuel clause.

The Big Bend Units 1-4 ignition conversion project capital costs, including depreciation and return, for the period are less than the fuel savings resulting from the project, and provide a net benefit to customers, as shown on Document No. 5, page 1, line 33. Therefore, the Big Bend Units 1-4 ignition conversion project capital costs should be recovered through the fuel clause in accordance with FPSC Order No. PSC-2014-0309-PAA-EI, issued in Docket No. 20140032-EI on June 12, 2014.

Q. Have you incorporated the Florida Corporate Income Tax Reduction, effective January 1, 2019, into the company's calculated revenue requirement?

A. Yes. The change in the corporate income tax rate, announced in September 2019 and retroactive to January 1, 2019, resulted in an adjustment to the capital cost recovery for the Big Bend Units 1-4 ignition conversion project. Document No. 5 of my exhibit shows the adjustment on Page 1, Line 26, and the original and post-state tax reform revenue requirement rate of return calculations are shown on Pages 2 through 5.

Optimization Mechanism

Q. Was Tampa Electric's sharing of Optimization Mechanism gains allocated in accordance with FPSC Order No. PSC-2017-0456-S-EI, issued in Docket Nos. 20170210-EI and 20160160-EI, on November 27, 2017?

A. Yes. As shown in the testimony and exhibit of Tampa Electric witness John C. Heisey filed contemporaneously in this docket, the sharing of Optimization Mechanism gains was allocated in accordance with FPSC Order No. PSC-2017-0456-S-EI. Total gains were $6,468,033. Under the sharing mechanism, Tampa Electric customers receive $5,287,213, and the company earned an incentive of $1,180,820 as a result of the company’s Optimization Mechanism activities during 2019. Customers received the gains from these transactions during 2019, and Tampa Electric requests Commission approval to collect the company’s $1,180,820 incentive in its 2021 fuel factors.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

M. ASHLEY SIZEMORE

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

A. My name is M. Ashley Sizemore. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Rates in the Regulatory Affairs department.

Q. Have you previously filed testimony in Docket No. 20200001-EI?

A. Yes, I submitted direct testimony on June 3, 2020, July 27, 2020 and revised the July 27, 2020 testimony on August 12, 2020.

Q. Has your job description, education, or professional experience changed since you last filed testimony in this docket?

A. No, it has not.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the proposed annual capacity cost recovery factors, and the proposed annual levelized fuel and purchased power cost recovery factors for January 2021 through December 2021. I also describe significant events that affect the factors and provide an overview of the composite effect on the residential bill of changes in the various cost recovery factors for 2021.

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

A. Yes. Exhibit No. MAS-3, consisting of three documents, was prepared under my direction and supervision. Document No. 1, consisting of four pages, is furnished as support for the projected capacity cost recovery factors. 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 2021 through December 2021 as well as Schedule H1 for 2018 through 2021. Document No. 3 provides a comparison of retail residential fuel revenues under the inverted or tiered fuel rate, which demonstrates that the tiered rate is revenue neutral.

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. MAS-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. MAS-3, Document No. 1, page 2 of 4. Tampa Electric requests recovery of $353,890 after jurisdictional separation, prior year true-up, and application of the revenue tax factor, for estimated expenses in 2021.

Q. Please summarize the proposed capacity cost recovery factors by metering voltage level for January 2021 through December 2021.

A.

Rate Class and Metering Voltage	**Capacity Cost Cents per kWh**	**Recovery Factor $ per kW**
RS Secondary	0.002	
GS and CS Secondary	0.002	
GSD, SBF Standard		
Secondary		0.01
Primary		0.01
Transmission		0.01
IS, IST, SBI		
Primary		0.00
Transmission		0.00
GSD Optional		
Secondary	0.002	
Primary	0.002	
Transmission	0.002	
LS1 Secondary	0.000	

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

Q. How does Tampa Electric's proposed average capacity cost recovery factor of 0.002 cents per kWh compare to the factor for June 2020 through December 2020?

A. The proposed capacity cost recovery factor of .002 cents per kWh for the January 2021 through December 2021 period is 0.014 cents per kWh (or $0.14 per 1,000 kWh) greater than the average capacity cost recovery factor credit of .012 cents per kWh for the June 2020 through December 2020 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 2021?

A. The appropriate amount for the 2021 period is 3.167 cents per kWh before the application of the time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. MAS-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 2021 through December 2021.

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

A. The Generating Performance Incentive Factor ("GPIF"), true-up factors, and Optimization Mechanism factor are provided on Schedule E1-C. Tampa Electric has calculated a GPIF reward of $2,858,056, which is included in the calculation of the total fuel and purchased power cost recovery factors. In addition, Schedule E1-C indicates the net true-up amount to be applied during the January 2021 through December 2021 period. The net true-up amount is an under-recovery of $25,479,055. Lastly, Schedule E1-C indicates the Optimization Mechanism gain of $1,180,820.

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 2021 through December 2021. The schedule also presents Tampa Electric's levelized fuel cost factors at each metering level.

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

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

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

A. Exhibit No. MAS-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 levelized fuel approach.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for January 2021 through December 2021.

A.

Metering Voltage Level	**Fuel Charge Factor (Cents per kWh)**
Secondary	3.167
Tier I (Up to 1,000 kWh)	2.856
Tier II (Over 1,000 kWh)	3.856
Distribution Primary	3.135
Transmission	3.104
Lighting Service	3.136
Distribution Secondary	3.335(on-peak)
	3.095(off-peak)

Metering Voltage Level	Fuel Charge Factor (Cents per kWh)
Distribution Primary	3.302(on-peak)
	3.064(off-peak)
Transmission	3.268(on-peak)
	3.033(off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 3.167 cents per kWh compare to the levelized fuel adjustment factor for the June 2020 through December 2020 period?

A. The proposed fuel charge factor of 3.167 cents per kWh is 0.529 cents per kWh (or $5.29 per 1,000 kWh) higher than the average fuel charge factor of 2.638 cents per kWh for the June 2020 through December 2020 period.

Wholesale Incentive Benchmark and Optimization Mechanism

Q. Will Tampa Electric project a 2021 wholesale incentive benchmark that is derived in accordance with Order No. PSC-2001-2371-FOF-EI issued in Docket No. 20010283-EI?

A. No. Effective January 1, 2018, as authorized by FPSC Order No. PSC-2017-0456-S-EI, issued in Docket No. 20160160-EI on November 27, 2017, the company's Optimization

Mechanism replaced the existing short-term wholesale sales incentive mechanism, and as a result no wholesale incentive benchmark is required for the 2021 projection.

Cost Recovery Factors

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

A. The composite effect on a residential bill for 1,000 kWh is an increase of $7.56 beginning January 2021, when compared to the September 2020 through December 2020 charges. These amounts are shown in Exhibit No. MAS-3, Document No. 2, on Schedule E10.

Q. When should the new rates take effect?

A. The new rates should take effect concurrent with meter readings for the first billing cycle for January 2021.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

M. ASHLEY SIZEMORE

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

A. My name is M. Ashley Sizemore. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Rates, in the Regulatory Affairs department.

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

A. I received a Bachelor of Arts degree in Political Science and a Master of Business Administration from the University of South Florida in 2005 and 2008, respectively. I joined Tampa Electric in 2010 as a Customer Service Professional. In 2011, I joined the Regulatory Affairs Department as a Rate Analyst. I spent six years in the Regulatory Affairs Department working on environmental, fuel and capacity cost recovery clauses. During the last three years as a Program Manager in

Customer Experience, I managed billing and payment customer solutions, products and services. I returned to the Regulatory Affairs Department in 2020 as Manager, Rates. My duties entail managing cost recovery for fuel and purchased power, interchange sales, capacity payments, and approved environmental projects. I have ten years of electric utility experience in the areas of customer experience and project management as well as the management of fuel and purchased power, capacity, and environmental cost recovery clauses.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to present, for Commission review and approval, the calculation of the January 2020 through December 2020 fuel and purchased power and capacity actual/estimated true-up amounts to be recovered in the January 2021 through December 2021 projection period. My testimony addresses the recovery of the fuel and purchased power costs as well as capacity costs for the year 2020, based on six months of actual data and six months of estimated data. This information will be used in the determination of the 2021 fuel and purchased power and capacity cost recovery factors.

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

A. Yes, I have prepared Exhibit No. MAS-2, which consists of four documents. Document No. 1 includes schedules E1-A, 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 2020 through December 2020. Document No. 2 provides the actual/estimated capacity cost recovery true-up amount for the period January 2020 through December 2020. Document No. 3 provides the actual/estimated capital costs during the period of January 2020 through December 2020 for projects authorized for recovery through the fuel clause. Document No. 3 also provides the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return for such projects. Document No. 4 provides the calculation for the Lake Hancock stipulated issue fuel savings. These documents are furnished as support for the actual/estimated 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 2021 through December 2021 fuel and purchased power cost recovery factors?

A. The estimated net true-up amount applicable for the period of January 2021 through December 2021 is an under-recovery of $25,479,055.

Q. How did Tampa Electric calculate the estimated net true-up to be applied in the January 2021 through December 2021 fuel and purchased power cost recovery factors?

A. The net true-up amount to be recovered in 2021 does not include the final true-up amount for the period January 2019 through December 2019 because this amount was returned to customers during 2020 in Tampa Electric's fuel mid-course factors, as approved in Order No. PSC-2020-0154-PCO-EI, issued May 14, 2020 in Docket No. 20200001-EI. The actual/estimated true-up amount for the period January 2020 through December 2020 is included in the January 2021 through December 2021 fuel and purchased power cost recovery factors. This calculation is shown on Schedule E1-A of Exhibit No. MAS-2, Document No. 1.

Q. What did Tampa Electric calculate as the actual/estimated fuel and purchased power cost recovery amount for the period January 2020 through December 2020?

A. The net 2020 actual/estimated fuel and purchased power cost recovery true-up is an under-recovery of $61,300,153 for the January 2020 through December 2020 period. This includes adjustments to reflect the company's mid-course correction true-up amounts. It is the actual/estimated under-recovery amount for the period January 2020 through December 2020, less the projected over-recovery true-up included in the period June 2020 through December 2020 mid-course correction factors, plus the difference between the 2019 actual/estimated true-up amount included in the original 2020 factors and the amount actually refunded before the mid-course correction factors became effective. The actual/estimated true-up for the period January 2020 through December 2020 is an under-recovery of $43,367,307. The detailed calculation supporting the actual/estimated current period true-up is shown in Exhibit No. MAS-2, Document No. 1 on Schedule E1-B. In addition, the calculation is shown on Schedule E1-A of Exhibit No. MAS-2, Document No. 1.

Q. Please explain the fuel savings credit for Lake Hancock Solar that was booked in February 2020.

A. In Order No. PSC-2018-0571, the Commission approved Tampa Electric's proposed set of Stipulations, wherein the company committed that if the 2019 actual fuel savings associated with the incremental 5 MW and the additional 17.7 MW of the Lake Hancock Solar project not included in the Second SoBRA did not equal or exceed $1,000,000, then the company would refund the shortfall to customers. The refund, reflected in February's A-Schedule, was $236,322. This is shown in Exhibit No. MAS-2, Document No. 1 on Schedule E1-B. In addition, the calculation is shown in Exhibit No. MAS-2, Document No. 4.

Q. What was the actual 2019 fuel savings associated with Lake Hancock's incremental 5 MW and additional 17.7 MW that was not included in the Second SoBRA tranche?

A. The actual fuel savings associated with Lake Hancock's incremental 5 MW and additional 17.7 MW not included in the second SoBRA tranche is $763,678. Tampa Electric refunded the difference of $236,322 to the customers.

Q. Were there any additional adjustments to the Fuel and Purchased Power cost recovery clause?

A. Yes. In July, Tampa Electric received a refund related to the Transco rate case settlement in the amount of $461,004 for charges incurred during the period of March 2019 through May 2020 (Docket No.: RP18-1126-003, Order Document No. 20200324-3028 filed on March 24, 2020).

Capacity Cost Recovery Clause

Q. What has Tampa Electric calculated as the estimated net true-up amount to be applied in the January 2021 through December 2021 capacity cost recovery factors?

A. The estimated net true-up amount applicable for January 2021 through December 2021 is an over-recovery of $1,771,480 as shown in Exhibit No. MAS-2, Document No. 2, page 1 of 4.

Q. How did Tampa Electric calculate the estimated net true-up amount to be applied in the January 2021 through December 2021 capacity cost recovery factors?

A. The net true-up amount to be recovered in the 2021 capacity cost recovery factors includes the sum of the final true-up amount for 2019 and the actual/estimated true-up amount for January 2020 and December 2020.

Q. What did Tampa Electric calculate as the final capacity cost recovery true-up amount for 2019?

A. The final 2019 true-up is an over-recovery of $111,228. The actual capacity cost under-recovery, including interest, was $2,067,989 for the period January 2019 through December 2019. This amount, less the $2,179,217 actual/estimated under-recovery amount approved in Order No. PSC-2019-0484-FOF-EI, issued November 18, 2019, in Docket No. 20190001-EI results in a net over-recovery amount for the period of $111,228 as identified in Exhibit No. MAS-2, Document No. 2, page 1 of 4.

Q. What did Tampa Electric calculate as the actual/estimated capacity cost recovery true-up amount for the period January 2020 through December 2020?

A. The actual/estimated true-up amount is an over-recovery of $5,870,171 as shown on Exhibit No. MAS-2, Document No. 2, page 1 of 4.

Q. What did Tampa Electric calculate as the net capacity cost recovery true-up amount for the period January 2020 through December 2020?

A. The net capacity cost recovery true-up amount for the period January 2020 through December 2020 is an over-recovery of $1,771,480. This calculation is shown on Exhibit No. MAS-2, Document No. 2, page 1 of 4.

Q. Please explain the credit of $4,856,329 that is reflected in the month of February and the credit of $4,069,905 that is reflected in the month of June on line 12 of Exhibit No. MAS-2, Document No. 2, page 2 of 4.

A. Pursuant to paragraph 6(n) of the 2017 Amended and Restated Stipulation and Settlement agreement, "…the difference between the cumulative base revenues since the implementation of the initial SoBRA factor and the cumulative base revenues that would have resulted if the revised SoBRA factor (for cost and in-service date true-ups) had been in place during the same time period will be trued up with interest at the AFUDC rate shown in Exhibit B used for the projects, and will be made through a one-time, twelve-month adjustment through the CCR clause." As submitted for Commission review and approval in Docket No. 20200144-EI, an estimated true-up for the First and Second SoBRAs totaling $4,856,329 was credited to the capacity clause in February 2020, and any additional adjustment required will be made upon resolution of Docket No. 20200144-EI. The June 2020 credit to the capacity clause represents the estimated true-up amount due to customers for the Third SoBRA actual in-service dates and will be adjusted as needed upon Commission review and approval of the final true-up amounts for the actual in-service dates and installed costs of the projects. This amount is expected to be finalized during 2021.

Capital Projects Approved for Fuel Clause Recovery

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

A. Document No. 3 of Exhibit No. MAS-2 provides the capital cost and fuel savings for the Big Bend Units 1 through 4 ignition conversion project for the period January 2020 through December 2020. This document also contains the capital structure components and cost rates relied upon to calculate the revenue requirement rate of return on capital projects recovered through the fuel clause.

Collection of the Big Bend Units 1 through 4 ignition conversion project capital costs was completed in May 2020. These costs, including depreciation and return, were less than the project fuel savings, as shown on Exhibit No. MAS-2, Document No. 3, Page 1, line 33.

Therefore, the Big Bend Units 1 through 4 ignition conversion project capital costs should be recovered through the fuel clause in accordance with FPSC Order No. PSC-2014-0309-PAA-EI, issued in Docket No. 20140032-EI on June 12, 2014.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Jeremy B. Cain was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JEREMY B. CAIN

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

A. My name is Jeremy Cain. 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 of Asset Management, Bayside Station.

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 2003 from the University of New Brunswick, Canada, and I am a registered Professional Engineer in Canada. I have accumulated 10 years of experience in the electric utility industry, with experience in the areas of unit maintenance manager, project manager for a unit upgrade, operations manager for that plant, as well as various other engineering positions, including responsibility for physical asset management. In my current role, I am responsible for development of Tampa Electric’s Asset Management programs and processes, specifically for the Bayside Power Station, and coordinating these programs with Asset Management programs throughout Energy Supply. Asset Management processes include work management processes, reliability programs, information technology, operational and capital investment analysis, recommendations, and planning to maintain and improve the performance of the generating units.

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 2019 through December 2019. I will also compare these results to the targets established for the period.

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

A. Yes, I prepared Exhibit No. JBC-1, consisting of two documents. Document No. 1, entitled “GPIF Schedules” is consistent with the GPIF Implementation Manual approved by the Commission. Document No. 2 provides the company’s Actual Unit Performance Data for the 2019 period.

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

A. Polk Units 1 and 2 and Bayside Units 1 and 2 are included in the calculation of the GPIF.

Q. Have you calculated the results of Tampa Electric's performance under the GPIF during the January 2019 through December 2019 period?

A. Yes, I have. This is shown on Document No. 1, page 4 of 22. Based upon 5.274 Generating Performance Incentive Points ("GPIP"), the result is a reward amount of $2,858,056 for the period.

Q. Please proceed with your review of the actual results for the January 2019 through December 2019 period.

A. On Document No. 1, page 3 of 22, the actual average common equity for the period is shown on line 14 as $3,015,639,377. This produces the maximum penalty or reward amount of $5,419,348 as shown on line 23.

Q. Will you please explain how you arrived at the actual equivalent availability results for the four 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 22, 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 22, 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:

Polk Unit No. 1

On this unit, 720 planned outage hours were originally scheduled for 2019. Actual outage activities required 419 planned outage hours. Consequently, the actual equivalent availability of 78.9 percent is adjusted to 77.0 percent, as shown on Document No. 1, page 7 of 22.

Polk Unit No. 2

On this unit, 576 planned outage hours were originally scheduled for 2019. Actual outage activities required 391.4 planned outage hours. Consequently, the actual equivalent availability of 92.6 percent is adjusted to 90.6 percent, as shown on Document No. 1, page 8 of 22.

Bayside Unit No. 1

On this unit, 624 planned outage hours were originally scheduled for 2019. Actual outage activities required 973.6 planned outage hours. Consequently, the actual equivalent availability of 85.1 percent is adjusted to 89.1 percent, as shown on Document No. 1, page 9 of 22.

Bayside Unit No. 2

On this unit, 671 planned outage hours were originally scheduled for 2019. Actual outage activities required 998 planned outage hours. Consequently, the actual equivalent availability of 85.5 percent is adjusted to 89.0 percent, as shown on Document No. 1, page 10 of 22.

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

A. The final adjusted equivalent availability for each unit is shown on Document No. 1, page 6 of 22, column 4. This number is incorporated in the respective GPIP table for each unit, shown on pages 17 through 20 of 22. Page 4 of 22 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 four GPIF units are shown on Document No. 1, page 6 of 22. 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 22, column 9. The heat rate value is incorporated in the respective GPIP table for each unit, shown on pages 17 through 20 of 22. Page 4 of 22 summarizes the weighted heat rate points to be awarded or penalized.

Q. What is the overall GPIP for Tampa Electric for the January

2019 through December 2019 period?

A. This is shown on Document No. 1, page 2 of 22. The weighting factors shown on page 4 of 22, column 3, plus the equivalent availability points and the heat rate points shown on page 4 of 22, column 4, are substituted within the equation found on page 22 of 22. The resulting value of 5.274 is in the GPIF table on page 2 of 22, and the reward amount of $2,858,056 is calculated using linear interpolation.

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

A. Yes. Incentive dollars are not to exceed 50 percent of fuel savings. Tampa Electric met this constraint, limiting the total potential reward and penalty incentive dollars to $5,419,348 as shown in Document No. 1, pages 2 and 3.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JEREMY B. CAIN

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

A. My name is Jeremy B. Cain. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Asset Management.

Q. Please provide a brief description of your educational background and work experience.

A. I received a Bachelor of Science degree in Mechanical Engineering in 2003 from the University of New Brunswick, Canada, and I am a registered Professional Engineer in Canada. I have over 11 years of experience in the electric utility industry, specifically in the roles of unit maintenance manager, project manager for a unit upgrade, operations manager for that plant, as well as various other engineering positions, including responsibility for asset management. In my current role, I am responsible for development of Tampa Electric’s Asset Management programs and processes, specifically for the Bayside Power Station, and coordinating these programs with the Asset Management processes throughout Energy Supply. Asset Management programs include work management processes, reliability programs, information technology, operational and capital investment analysis, recommendations, and planning in order to maintain and improve the performance of the generating units.

Q. What is the purpose of your testimony?

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

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

A. Yes. Exhibit No. JC-1, 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 2021 period.

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

A. Four natural gas combined cycle units and one coal unit are included. These are Polk Units 1 and 2, Bayside Units 1 and 2, and Big Bend Unit 4.

Q. Does your exhibit comply with the Commission's approved GPIF methodology?

A. Yes. In accordance with the GPIF Manual, the GPIF units selected represent no less than 80 percent of the estimated system net generation. The units Tampa Electric proposes to use for the period January 2021 through December 2021 represent 87.4 percent of the total forecasted system net generation for this period.

To account for the concerns presented in the testimony of Commission Staff witness Sidney W. Matlock during the 2005 fuel hearing, Tampa Electric removes outliers from the calculation of the GPIF targets. The methodology was approved by the Commission in Order No. PSC-2006-1057-FOF-EI issued in Docket No. 20060001-EI on December 22, 2006.

Q. Did Tampa Electric identify any outages as outliers?

A. Yes, Polk Unit 1, Polk Unit 2, and Bayside Unit 1 outages were identified as outliers and were removed.

Q. Did Tampa Electric make any other adjustments?

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

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

A. Targets were established for equivalent availability and heat rate for each unit considered for the 2021 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 five units included within the GPIF are shown on page 5 of Document No. 1.

To give an example for the 2021 period, the projected EUOF for Bayside Unit 1 is 2.3 percent, the POF is 3.8 percent. Therefore, the target EAF for Bayside Unit 1 equals 93.9 percent or:

$$100\% - (2.3\% + 3.8\%) = 93.9\%$$

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 using the following formula:

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

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

$$EAF_{MAX} = 1 – [0.80 (2.3\%) + 0.95 (3.8\%)] = 94.5\%$$

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

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

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

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

Again, continuing using the Bayside Unit 1 example,

$$EAF_{MIN} = 1 - [1.40\ (2.3\%) + 1.10\ (3.8\%)] = 92.6\%$$

The equivalent availability maximum and minimum for the other four 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 2021 are shown on page 17 of Document No. 1. Two GPIF units have a major planned outage of 28 days or greater in 2021; therefore, two Critical Path Method Diagrams are provided.

Planned Outage Factors are calculated for each unit. For example, Bayside Unit 1 is scheduled for planned outages from March 15, 2021 to March 28, 2021. There are 336 planned outage hours scheduled for the 2021 period, with a total of 8,760 hours during this 12-month period. Consequently, the POF for Bayside Unit 1 is 3.8 percent or:

$$\frac{336}{8,760} \times 100\% = 3.8\%$$

The factor for each unit is shown on pages 5 and 12 through 16 of Document No. 1. Polk Unit 1 has a POF of 7.7 percent. Polk Unit 2 has a POF of 16.2 percent. Bayside Unit 2 has a POF of 3.8 percent, and Big Bend Unit 4 has a POF of 16.2 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 2.3 percent for Bayside Unit 1. The EUOF of Bayside Unit 1 is verified by the data shown on page 15, lines 3, 5, 10, and 11 of Document No. 1 and calculated using the following formula:

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

Or

$$EUOF = \frac{(95 + 106)}{8,760} \times 100\% = 2.3\%$$

Relative to Bayside Unit 1, the EUOF of 2.3 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Polk Unit 1

The projected EUOF for this unit is 14.6 percent. The unit will have two planned outages in 2021, and the POF is 7.7 percent. Therefore, the target equivalent availability for this unit is 77.7 percent.

Polk Unit 2

The projected EUOF for this unit is 3.2 percent. The unit will have two planned outages in 2021, and the POF is 16.2 percent. Therefore, the target equivalent availability for this unit is 80.6 percent.

Bayside Unit 1

The projected EUOF for this unit is 2.3 percent. The unit will have one planned outage in 2021, and the POF is 3.8 percent. Therefore, the target equivalent availability for this unit is 93.9 percent.

Bayside Unit 2

The projected EUOF for this unit is 5.2 percent. The unit will have one planned outage in 2021, and the POF is 3.8 percent. Therefore, the target equivalent availability for this unit is 90.9 percent.

Big Bend Unit 4

The projected EUOF for this unit is 29.9 percent. The unit will have two planned outages in 2021, and the POF is 16.2 percent. Therefore, the target equivalent availability for this unit is 54 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 88.4 percent is shown on page 5 of Document No. 1.

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

A. The adjustment makes the factors more accurate and comparable. A unit in a planned outage stage or reserve shutdown stage cannot incur a forced or maintenance outage. To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent

Unplanned Outage Factor for Bayside Unit 1 on page 15 of Document No. 1. Except for the month of March, the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled for these months. During the month of March, the Equivalent Unplanned Outage Rate exceeds the Equivalent Unplanned Outage Factor due to the scheduled planned outages. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

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

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

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

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

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

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

Q. How were the targets determined?

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

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

A. The ranges were determined through analysis 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 25 through 29 of Document No. 1.

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

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

Q. Please summarize your heat rate projection (Btu/Net kWh) and the range about each target to allow for potential improvement or degradation for the 2021 period.

A. The heat rate target for Polk Unit 1 is 9,684 Btu/Net kWh with a range of ±664 Btu/Net kWh. The heat rate target for Polk Unit 2 is 6,940 Btu/Net kWh with a range of ±185 Btu/Net kWh. The heat rate for Bayside Unit 1 is 7,352 Btu/Net kWh with a range of ±108 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 7,439 Btu/Net kWh with a range of ±121 Btu/Net kWh. The heat rate target for Big

Bend Unit 4 is 11,576 Btu/Net kWh with a range of ±615 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within a range for each target. This is shown on page 4, and pages 7 through 11 of Document No. 1.

Q. Do these heat rate targets and ranges meet the Commission’s requirements?

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 determining the GPIF targets?

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 in Document No. 1, pages 7 through 11. 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 $459,381,860 is shown on Document No. 1, 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.

Column 4 totals $14,003,920 which reflects the savings if all of the units operated at maximum improvement. A weighting factor for each metric is then calculated by dividing unit savings by the total. For Bayside Unit 1, the weighting factor for average net operating heat rate is 10.83 percent as shown in the right-hand column on Document No. 1, page 6. Pages 7 through 11 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, as shown on page 10 of Document No. 1, if Bayside Unit 1, operates at 7,244 average net operating heat rate, fuel savings would equal $1,516,300 and +10 average net operating heat rate points would be awarded.

The GPIF Reward/Penalty table on page 2 of Document No. 1 is a summary of the tables on pages 7 through 11. 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 $14,003,920. 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 2021 is $3,589,402,384. This produces the maximum allowed jurisdictional incentive of $12,003,035 shown on line 21.

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

A. Yes. As Order No. PSC-2013-0665-FOF-EI, issued in Docket No. 20130001-EI on December 18, 2013 states, incentive dollars are not to exceed 50 percent of fuel savings. Page 2 of Document No. 1 demonstrates that this constraint is met, limiting total potential reward and penalty incentive dollars to $7,001,961.

Q. Please summarize your direct testimony.

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

$$
\begin{aligned}
GPIP = (&0.0482\ EAP_{PK1} + 0.0153\ EAP_{PK2} \\
&+ 0.1601\ EAP_{BAY1} + 0.0745\ EAP_{BAY2} \\
&+ 0.0129\ EAP_{BB4} + 0.2374\ HRP_{PK2} \\
&+ 0.1083\ HRP_{BAY1} + 0.1231\ HRP_{BAY2} \\
&+ 0.1368\ HRP_{BB4} + 0.0834\ HRP_{PK1})
\end{aligned}
$$

Where:

GPIP = Generating Performance Incentive Points

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

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

Q. Have you prepared a document summarizing the GPIF targets for the January through December 2021 period?

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

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Transcript continues in sequence in Volume 2.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

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

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

DATED this 4th day of November, 2020.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
EXPIRES AUGUST 13, 2024