BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20220001-EI

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.
________________________________/

VOLUME 2
PAGES 229 - 335

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN ANDREW GILES FAY
COMMISSIONER ART GRAHAM
COMMISSIONER GARY F. CLARK
COMMISSIONER MIKE LA ROSA
COMMISSIONER GABRIELLA PASSIDOMO

DATE: Thursday, November 17, 2022

TIME: Commenced: 9:30 a.m.
Concluded: 4:40 p.m.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

APPEARANCES: (As heretofore noted.)

PREMIER REPORTING
112 W. 5TH AVENUE
TALLAHASSEE, FLORIDA
(850) 894-0828

I N D E X

EXHIBITS

NUMBER:		ID	ADMITTED
1	Comprehensive Exhibit List	309	310
2-69	As identified in the CEL	309	
38-69	As identified in the CEL	311	
8-21	As identified in the CEL	311	
25-37	As identified in the CEL	311	

P R O C E E D I N G S

(Transcript follows in sequence from Volume 1.)

(Whereupon, prefiled direct testimony of Patrick A. Bokor was inserted.)

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220001-EI
IN RE: FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR
TRUE-UP
JANUARY 2021 THROUGH DECEMBER 2021

TESTIMONY AND EXHIBIT
OF
PATRICK A. BOKOR

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PATRICK A. BOKOR

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

A. My name is Patrick A. Bokor. 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, Gas & Power Trading.

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

A. I received a Bachelor of Science degree in Accounting in 2000 from the University of Florida and a Master of Business Administration in 2010 from the University of Tampa. I have accumulated 16 years of experience in the electric industry, with experience in the areas of unit commitment and economic dispatch, power and gas trading, accounting, and risk management. In my current role, I am responsible for the oversight of trading activities for the gas and power traders. Specifically, I am responsible for natural gas and power trading activities and work closely with the company’s unit commitment team to provide low cost, reliable power to our customers. In addition, I am responsible for portfolio optimization and the Optimization Mechanism as it relates to natural gas and power.

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 2021 through December 2021. 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. PAB-1, consisting of two documents. Document No. 1, entitled “GPIF Schedules” is consistent with the GPIF Implementation Manual approved by the Florida Public Service Commission (“FPSC” or “Commission”). Document No. 2 provides the company’s Actual Unit Performance Data for the 2021 period.

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

A. Polk Units 1 and 2, Bayside Units 1 and 2, and Big Bend Unit 4 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 2021 through December 2021 period?

A. Yes, I have. This is shown on Document No. 1, page 4 of 26. Based upon 0.780 Generating Performance Incentive Points ("GPIP"), the result is a reward amount of $546,170 for the period.

Q. Please proceed with your review of the actual results for the January 2021 through December 2021 period.

A. On Document No. 1, page 3 of 26, the actual average common equity for the period is shown on line 14 as $3,796,594. This produces the maximum penalty or reward amount of $7,001,961 as shown on line 23.

Q. Will you please explain how you arrived at the actual equivalent availability results for the five 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 monthly. 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 26, 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 26, column 4. The necessary adjustments as prescribed in the GPIF Manual are further defined by a letter dated October 23, 1981, from Mr. J. H. Hoffsis of the Commission’s Staff. The adjustments for each unit are as follows:

Big Bend Unit No. 4

On this unit, 1,416 planned outage hours were originally scheduled for 2021. Actual outage activities required 1,638.6 planned outage hours. Consequently, the actual equivalent availability of 55.0 percent is adjusted to 70.6 percent, as shown on Document No. 1, page 7 of 26.

Polk Unit No. 1

On this unit, 672 planned outage hours were originally scheduled for 2021. Actual outage activities required 779.3 planned outage hours. Consequently, the actual equivalent availability of 45.7 percent is adjusted to 46.3 percent, as shown on Document No. 1, page 8 of 26.

Polk Unit No. 2

On this unit, 1,416 planned outage hours were originally scheduled for 2021. Actual outage activities required 966.8 planned outage hours. Consequently, the actual equivalent availability of 85.3 percent is adjusted to 80.3 percent, as shown on Document No. 1, page 9 of 26.

Bayside Unit No. 1

On this unit, 336 planned outage hours were originally scheduled for 2021. Actual outage activities required 472 planned outage hours. Consequently, the actual equivalent availability of 88.8 percent is adjusted to 90.3 percent, as shown on Document No. 1, page 10 of 26.

Bayside Unit No. 2

On this unit, 336 planned outage hours were originally scheduled for 2021. Actual outage activities required 480.3 planned outage hours. Consequently, the actual equivalent availability of 92.6 percent is adjusted to 94.3 percent, as shown on Document No. 1, page 11 of 26.

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

A. The final adjusted equivalent availabilities for each unit are shown on Document No. 1, page 6 of 26, column 4. This number is incorporated in the respective GPIP table for each unit, shown on pages 20 through 24 of 26. Page 4 of 26 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 five GPIF units are shown on Document No. 1, page 6 of 26. 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 26, column 9. The heat rate value is incorporated in the respective GPIP table for each unit, shown on pages 20 through 24 of 26. Page 4 of 26 summarizes the weighted heat rate points to be awarded or penalized.

Q. What is the overall GPIP for Tampa Electric for the January 2021 through December 2021 period?

A. This is shown on Document No. 1, page 2 of 26. The weighting factors shown on page 4 of 26, column 3, plus the equivalent availability points and the heat rate points shown on page 4 of 26, column 4, are substituted within the equation found on page 26 of 26. The resulting value of 0.780 is in the GPIF table on page 2 of 26, and the reward amount of $546,170 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 $7,001,961 as shown in Document No. 1, page 3.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR
PROJECTIONS
JANUARY 2023 THROUGH DECEMBER 2023

TESTIMONY AND EXHIBIT
OF
PATRICK A. BOKOR

FILED: SEPTEMBER 2, 2022

TAMPA ELECTRIC COMPANY
DOCKET NO. 20220001-EI
FILED: 09/02/2022

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

PATRICK A. BOKOR

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

A. My name is Patrick A. Bokor. 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, Gas & Power Trading.

Q. Please provide a brief description of your educational background and work experience.

A. I received a Bachelor of Science degree in Accounting in 2000 from the University of Florida and a Master of Business Administration in 2010 from the University of Tampa. I have over 16 years of experience in the electric industry, in the areas of unit commitment and economic dispatch, power and gas trading, accounting, finance, and risk management. In my current role, I am responsible for managing the procurement and delivery of wholesale natural gas and power for Tampa Electric’s portfolio.

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. PAB-2, consisting of two documents, was prepared under my direction and supervision. Document No. 1 contains the GPIF schedules. Document No. 2 is a summary of the GPIF targets for the 2023 period.

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

A. Three natural gas combined cycle ("CC") units and one coal unit are included. These are Polk Unit 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 2023 through December 2023 represent the top 97.4 percent of the total forecasted system net generation for this period excluding the Big Bend Unit 1 CC (Big Bend Modernization). The Big Bend Unit 1 CC is expected to enter commercial service in December 2022 and was excluded from the GPIF calculation because the company does not have historical operational data on which to base targets.

To account for the concerns presented in the testimony of Commission Staff witness Sidney W. Matlock during the 2005 fuel hearing, Tampa Electric removes outliers from the calculation of the GPIF targets. The methodology was approved by the Commission in Order No. PSC-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, Big Bend Unit 4 and Polk Unit 2 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 2023 period. A range of potential improvements and degradations were determined for each of these metrics.

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

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

To give an example for the 2023 period, the projected EUOF for Big Bend Unit 4 is 19.9 percent, the POF is 18.9 percent. Therefore, the target EAF for Big Bend Unit 4 equals 61.2 percent or:

$$100\% - (19.9\% + 18.9\%) = 61.2\%$$

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 Big Bend Unit 4 example:

$$EAF_{MAX} = 1 - [0.80\ (19.9\%) + 0.95\ (18.9\%)] = 66.1\%$$

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 Big Bend Unit 4 example,

$$EAF_{MIN} = 1 - [1.40\ (19.9\%) + 1.10\ (18.9\%)] = 51.4\%$$

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 2023 through December 2023 are shown on page 15 of Document No. 1. Two GPIF units have a major planned outage of 28 days or greater in 2023; therefore, two Critical Path Method Diagrams are provided.

Planned Outage Factors are calculated for each unit. For example, Big Bend Unit 4 is scheduled for planned outages from April 1, 2023 to May 25, 2023 and from November 7, 2023 to November 20, 2023. There are 1,656 planned outage hours scheduled for the 2023 period, with a total of 8,760 hours during this 12-month period. Consequently, the POF for Big Bend Unit 4 is 18.9 percent or:

$$\frac{1{,}656}{8{,}760} \times 100\% = 18.9\%$$

The factor for each unit is shown on pages 5 and 11 through 14 of Document No. 1. Polk Unit 2 has a POF of 3.8 percent, Bayside Unit 1 has a POF of 5.3 percent, and Bayside Unit 2 has a POF of 21.8 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 19.9 percent for Big Bend Unit 4. The EUOF of Big Bend Unit 4 is verified by the data shown on page 11, lines 3, 5, 10, and 11 of Document No. 1 and calculated using the following formula:

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

Or

$$EUOF = \frac{(1,049 + 695)}{8,760} \times 100\% = 19.9\%$$

Relative to Big Bend Unit 4, the EUOF of 19.9 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Polk Unit 2

The projected EUOF for this unit is 5.3 percent. The unit will have two planned outages in 2023, and the POF is 3.8 percent. Therefore, the target equivalent availability for this unit is 90.9 percent.

Bayside Unit 1

The projected EUOF for this unit is 4.7 percent. The unit will have one planned outage in 2023, and the POF is 5.3 percent. Therefore, the target equivalent availability for this unit is 90.0 percent.

Bayside Unit 2

The projected EUOF for this unit is 3.1 percent. The unit will have one planned outage in 2023, and the POF is 21.8 percent. Therefore, the target equivalent availability for this unit is 75.2 percent.

Big Bend Unit 4

The projected EUOF for this unit is 19.9 percent. The unit will have two planned outages in 2023, and the POF is 18.9 percent. Therefore, the target equivalent availability for this unit is 61.2 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 81.6 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 Big Bend Unit 4 on page 11 of Document No. 1. Except for the months of May and November, the Equivalent Unplanned Outage Rate and Equivalent Unplanned Outage Factor are equal. This is because no planned outages are scheduled for these months. During the months of May and November, the Equivalent Unplanned Outage Rate exceeds the Equivalent Unplanned Outage Factor due to the scheduled planned outages. Therefore, the adjusted factors apply to the period hours after the planned outage hours have been extracted.

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

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

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

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

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

A. Yes. Target heat rates and ranges of potential operation have been developed as required and have been adjusted to reflect the 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 22 through 25 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 2023 period.

A. The heat rate target for Polk Unit 2 is 7,279 Btu/Net kWh with a range of ±191 Btu/Net kWh. The heat rate for Bayside Unit 1 is 7,481 Btu/Net kWh with a range of ±174 Btu/Net kWh. The heat rate target for Bayside Unit 2 is 8,280 Btu/Net kWh with a range of ±302 Btu/Net kWh. The heat rate target for Big Bend Unit 4 is 10,777 Btu/Net kWh with a range of ±720 Btu/Net kWh. A zone of tolerance of ±75 Btu/Net kWh is included within a range for each target. This is shown on pages 7 through 10 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 10. The baseline production costing analysis was performed to calculate the total system fuel cost if all units operated at target heat rate and target availability for the period. This total system fuel cost of $831,414,630 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 $17,848,884 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 Big Bend Unit 4, the weighting factor for average net operating heat rate is 26.52 percent as shown in the right-hand column on Document No. 1, page 6. Pages 7 through 10 of Document

No. 1 show the point table, the Fuel Savings/(Loss) and the equivalent availability or heat rate value. The individual weighting factor is also shown. For example, as shown on page 7 of Document No. 1, if Big Bend Unit 4, operates at 10,058 average net operating heat rate, fuel savings would equal $4,734,231 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 10. The left-hand column of this document shows the incentive points for Tampa Electric. The center column shows the total fuel savings and is the same amount as shown on page 6, column 4, or $17,848,884. 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 2023 through December 2023 is $4,460,054,782. This produces the maximum allowed jurisdictional incentive of $14,976,288 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 $8,924,442.

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).

$$\begin{aligned} GPIP = (&0.0787\ EAP_{PK2} + 0.0594\ EAP_{BAY1} \\ &+ 0.0113\ EAP_{BAY2} + 0.0566\ EAP_{BB4} \\ &+ 0.2852\ HRP_{PK2} + 0.1460\ HRP_{BAY1} \\ &+ 0.0976\ HRP_{BAY2} + 0.2652\ HRP_{BB4}) \end{aligned}$$

Where:

GPIP = Generating Performance Incentive Points

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

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

Q. Have you prepared a document summarizing the GPIF targets for the January 2023 through December 2023 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.

(Whereupon, prefiled direct testimony of Benjamin F. Smith, II was inserted.)

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2023 THROUGH DECEMBER 2023

TESTIMONY
OF
BENJAMIN F. SMITH II

FILED: SEPTEMBER 2, 2022

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

BENJAMIN F. SMITH II

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

A. My name is Benjamin F. Smith II. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Gas and Power Origination within the Fuel and Planning Services Department.

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

A. I received a Bachelor of Science degree in Electric Engineering in 1991 from the University of South Florida in Tampa, Florida, and a Master of Business Administration degree in 2015 from Saint Leo University in Saint Leo, Florida. I am also a registered Professional Engineer within the State of Florida and a Certified Energy Manager through the Association of Energy Engineers. I joined Tampa Electric in 1990 as a cooperative education student.

During my years with the company, I have worked in the areas of transmission engineering, distribution engineering, resource planning, retail marketing, and wholesale power marketing. I am currently the Manager, Gas and Power Origination within the Origination and Trading Department. My responsibilities are to evaluate short and long-term power purchase and sale opportunities within the wholesale power market, assist in wholesale power and gas transportation origination and contract structures, and assist in combustion byproduct contract administration and market opportunities. In this capacity, I interact with wholesale power market participants such as utilities, municipalities, electric cooperatives, power marketers, other wholesale developers and independent power producers, as well as with natural gas pipeline owners and transporters.

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

A. Yes. I have submitted written testimony in the annual fuel docket since 2003, and I have testified before this Commission in Docket Nos. 20030001-EI, 20040001-EI, and 20080001-EI regarding the appropriateness and prudence of Tampa Electric's wholesale purchases and sales.

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

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

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

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

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

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

A. Yes, it has. Tampa Electric has fully complied with, and continues to fully comply with, the Commission's Order No. PSC-1997-0262-FOF-EI, approved on March 11, 1997 and issued in Docket No. 19970001-EI, which governs the treatment of separated and non-separated wholesale sales. The company's wholesale purchase and sale activities and transactions are also reviewed and audited on a recurring basis by the Commission.

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

Q. Please describe Tampa Electric’s 2022 wholesale power purchases.

A. Tampa Electric assessed the wholesale power market and entered into short- and long-term purchases based on price and availability of supply. Approximately 7 percent of the company’s expected needs for 2022 will be met using purchased power. This includes economy energy purchases, reliability purchases, as-available purchases from qualifying facilities, and forward purchases from Duke Energy Florida (“DEF”), the Florida Municipal Power Agency (“FMPA”), and Florida Power & Light (“FPL”).

Presently, Tampa Electric has four forward purchases applicable to the year 2022, and those purchases are summarized below.

- A non-firm purchase from DEF, which was an extension of Tampa Electric’s previous contract to purchase non-firm energy from DEF. In November 2021, Tampa Electric and DEF extended this contract to cover the period December 2021 through October 2022. The energy volume available under the contract remains at a maximum of 515 MW per hour. The DEF extension does not have a must-take obligation and provides Tampa Electric the flexibility to schedule the energy when beneficial to customers. As an added component to this latest extension, 250 MW of the contract was available as a firm call option for the months of January and February 2022. The firm portion of the purchase was for reliability to ensure energy service to customers in the event Tampa Electric experienced cold weather. The purchase supported the company’s plan to lower exposure to natural gas risk during its winter peak. The company’s plan to minimize its natural gas risk is addressed in the testimony of witness John Heisey. Since the contract extension, the purchase has provided $6.7 million in projected savings to customers, which flow through the optimization mechanism. These savings to customers include only the utilization of the purchase as non-firm, economy (i.e., excludes the 250 MW firm call option portion). These savings flow through the company’s optimization mechanism and benefit customers in accordance with the methodology approved by the Commission in Order No. 2017-0456-S-EI, issued on November 27, 2017 and extended through December 31, 2024 as approved by the Commission in Order No. PSC-2021-0423-S-EI issued on November 10, 2021, in Docket No. 20210034-EI.

- A 50 MW firm peaking call option from FMPA executed November 2021 for the period January through February 2022. The firm purchase from FMPA was for reliability to ensure energy service to customers in the event Tampa Electric experienced unusually cold weather.

The company’s remaining two forward purchases are from FPL, executed in February 2022. A description of the purchases follows.

- The two FPL purchases are non-firm, economy, must-take energy purchases. Each purchase is for 150 MW. One covers the period May through October 2022. The other covers the period May through September 2022. The purchases provide a projected $4.6 million in savings to customers, which flow through the optimization mechanism.

At the time of the 2022 Projection filing, Tampa Electric did not expect forward purchases for 2022. However, the company did expect to incur capacity costs to be recovered through its 2022 Capacity Cost Recovery Clause in the form of projected firm transmission services. The projected capacity clause costs for firm transmission totaled $5.9 million and would be in support of firm purchases for the Big Bend Modernization project (“Modernization Project”) testing, if needed, as well as economic forward purchases. Although the company did not make firm purchases in support of testing at Big Bend, it did make the previously mentioned must-take economy purchases from FPL, which required the purchase of firm transmission. Currently, the projected 2022 transmission costs to be recovered through the 2022 Capacity Cost Recovery Clause is about $5.1 million.

Tampa Electric has not secured other forward purchases for 2022 at this time. However, the company constantly searches for economic purchase opportunities that benefit customers. As other purchase opportunities materialize, the company evaluates each product to determine the viability of making it part of the supply portfolio Tampa Electric uses to serve customers.

Q. Does Tampa Electric anticipate entering into new wholesale power purchases for 2023 and beyond?

A. Tampa Electric currently has no forward purchases for 2023 and, at this time, projects approximately 1 percent of the company's expected needs for 2023 will be met using purchased power. However, the company will search for forward economy purchase opportunities, which could result in capacity costs from the purchase of firm transmission services. Thus, the company has included a forecast of these transmission costs in its 2023 Capacity Cost Recovery Clause projection. The projected capacity clause costs total $1.7 million and support economic forward purchases. A further explanation of these transmission costs is below.

Over the past several years, as noted previously with the economic purchases from FPL in 2022, Tampa Electric has identified forward, season-long economy energy purchases that produced savings for customers, and it will seek out such beneficial purchases again in 2023. However, with the operation of the highly efficient Modernization Project, the company anticipates a lower volume of forward economy purchases than in previous years. Hence, the projected transmission costs for 2023 are lower than the projection for 2022. The company’s projected transmission costs are based on its expected system energy costs with the Modernization Project in service and market expectations. While Tampa Electric has yet to identify and secure economic purchase opportunities for 2023, the company included in its projection the dollars associated with these transmission costs. The terms of the company’s recent forward economy purchases were generally in the April through November timeframe and for about 300 MW. In 2023, the company's transmission cost projection is for 100 MW over the May through October timeframe.

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

A. During hurricane season, Tampa Electric continues to utilize a purchased power risk management strategy to minimize potential power supply disruptions. The strategy includes monitoring storm activity; evaluating the impact of storms on existing forward purchases and the rest of the wholesale power market; communicating with suppliers about their storm preparations and potential impacts to existing transactions, purchasing additional power on the forward market, if appropriate, for reliability and economics; evaluating transmission availability and the geographic location of electric resources; reviewing sellers' fuel sources and dual-fuel capabilities; and focusing on fuel-diversified purchases. Absent the threat of a hurricane, and for all other months of the year, the company evaluates economic combinations of short- and long-term purchase opportunities in the marketplace.

Q. Please describe Tampa Electric's wholesale energy sales for 2022 and 2023.

A. Tampa Electric entered into various non-separated (*e.g.,* next-hour and next-day sales) wholesale sales in 2022, and the company anticipates making additional non-separated sales during the balance of 2022 and 2023. The gains from these sales are shared between Tampa Electric and its customers through the company's optimization mechanism.

Q. Please summarize your direct testimony.

A. Tampa Electric monitors and assesses the wholesale power market to identify and take advantage of opportunities in the marketplace, and these efforts benefit the company's customers. Tampa Electric's energy supply strategy includes self-generation and short- and long-term power purchases. The company purchases in both physical forward and spot wholesale power markets to provide customers with a reliable supply at the lowest possible cost. In addition to the cost benefits, this purchased power approach employs a diversified physical power supply strategy that enhances reliability. The company also enters wholesale sales that benefit customers when market conditions allow.

Q. Does this conclude your direct testimony?

A. Yes.

(Whereupon, prefiled direct testimony of John C. Heisey was inserted.)

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220001-EI

IN RE: FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

2021 OPTIMIZATION MECHANISM

TESTIMONY AND EXHIBIT

JOHN C. HEISEY

FILED: APRIL 1, 2022

TAMPA ELECTRIC COMPANY
DOCKET NO. 20220001-EI
FILED: 4/1/2022

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOHN C. HEISEY

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

A. My name is John C. Heisey. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Origination and Trading.

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

A. I graduated from Pennsylvania State University with a Bachelor of Science in Business Logistics. I have over 25 years of power and natural gas trading experience, including employment at TECO Energy Source, FPL Energy Services, El Paso Energy, and International Paper. Prior to joining Tampa Electric, I was Vice President of Asset Trading for the Entegra Power Group LLC ("Entegra") where I was responsible for Entegra's energy trading activities. Entegra managed a large quantity of merchant capacity in bilateral and organized markets. I joined Tampa Electric in September 2016 as the Manager of Gas and Power Trading. I have held the position of Director, Origination and Trading since August 2021. In this role, I am responsible for directing all activities associated with the procurement and delivery of energy commodities for Tampa Electric's generation fleet. Such activities include the trading, optimization, strategy, planning, origination, compliance and regulatory oversight of natural gas, power, coal, oil, byproducts, and associated delivery. I am also responsible for all aspects of the Optimization Mechanism.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present, for the Commission's review, the 2021 results of Tampa Electric's activities under the Optimization Mechanism, as authorized by FPSC Order No. PSC-2017-0456-S-EI, issued in Docket No. 20160160-EI on November 27, 2017, and as extended for a three-year period beginning January 1, 2022 per FPSC Order No. PSC-2021-0423-S-EI, issued in Docket No. 20210034-EI on November 10, 2021.

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

A. Yes. Exhibit No. JCH-1, entitled Optimization Mechanism Results, was prepared under my direction and supervision. My exhibit shows the gains for each type of activity included in the Optimization Mechanism and the sharing of gains between customers and the company.

Q. Please provide an overview of the Optimization Mechanism.

A. The Optimization Mechanism is designed to create additional value for Tampa Electric's customers while also providing an incentive to the company if certain customer-value thresholds are achieved. The Optimization Mechanism includes gains from wholesale power sales and savings from wholesale power purchases, as well as gains from other forms of asset optimization.

Q. Please describe Tampa Electric's Optimization Mechanism submitted in Docket No. 20160160-EI and approved by Order No. PSC-2017-0456-S-EI, and extended by Order No. PSC-2021-0423-S-EI in Docket No. 20210034-EI.

A. Effective January 1, 2018, for the four-year period from

2018 through 2021, gains on all optimization mechanism activities, including short-term wholesale sales, short-term wholesale purchases, and all forms of asset optimization undertaken each year will be shared between shareholders and customers. The sharing thresholds are (a) for the first $4.5 million per year, 100 percent of gains to customers; (b) for gains greater than $4.5 million per year and less than $8.0 million per year, split 60 percent to shareholders and 40 percent to customers; and (c) for gains greater than $8.0 million per year, 50-50 sharing between shareholders and customersThe Optimization Mechanism will continue for an additional three years, through December 31, 2024, as authorized by the Commission in Order No. PSC-2021-0423-S-EI, issued on November 10,2021. While the Optimization sharing thresholds will continue in its current form, additional changes were included such that 1) any natural gas pipeline revenue from the release of natural gas pipeline capacity by Tampa Electric will be credited, in its entirety to retail customers, through the fuel clause and 2) any retirement/release of rail cars will be taken into account through the fuel clause and not subject to sharing through the Optimization Mechanism.

Optimization Mechanism Transactions

Q. Please provide the details of Tampa Electric's short-term wholesale sales under the Optimization Mechanism for 2021.

A. Optimization Mechanism gains from wholesale sales were $1,023,666 or 8 percent of optimization gains for 2021. The monthly detail is shown in my exhibit in the schedule "Wholesale Sales-Table 3."

Q. Please provide the details of Tampa Electric's short-term wholesale purchases under the Optimization Mechanism for 2021.

A. Optimization Mechanism gains from wholesale purchases were $8,692,298 or 65 percent of optimization gains for 2021. The monthly detail can be found in my exhibit on the schedule labeled "Wholesale Purchases-Table 4."

Q. Please describe Tampa Electric's asset optimization activities and the gains from those transactions under the Optimization Mechanism for 2021.

A. Optimization Mechanism gains from asset optimization activities were $3,723,768 or 27 percent of optimization gains for 2021. The gains from asset optimization activities are shown in my exhibit at "Asset Optimization Detail-Table 5."

A description of Tampa Electric's 2021 asset optimization activities is provided below.

- Delivered solid fuel and or transportation capacity sales using existing transport - sell coal and coal transportation, using Tampa Electric's existing coal and transportation capacity during periods when it is not needed to serve Tampa Electric's native electric load;
- Asset Management Agreement ("AMA") - outsource optimization functions to a third party through assignment of power, transportation and/or storage rights in exchange for a premium to be paid to Tampa Electric.
- Gas storage utilization – release contracted storage space or sell stored gas during periods when it is not needed to serve Tampa Electric's native electric load.
- Production (upstream) area sales – sell gas in gas-production areas when it is not needed to serve Tampa Electric's native electric load.

Q. Please summarize the activities and results of the Optimization Mechanism for 2021.

A. Tampa Electric participated in the following Optimization Mechanism activities in 2021: wholesale power purchases and sales, delivered solid fuel sales, natural gas storage AMAs, gas storage utilization, and production (upstream) area sales. The optimization gains for 2021 were $13,439,732 which exceeded the $4,500,000 threshold by $8,939,732 as shown in my exhibit on schedule "Total Gains Threshold Schedule-Table 1." Customer benefits were $8,619,866, and company benefits were $4,819,866 in 2021.

Q. Did Tampa Electric incur incremental Optimization Mechanism costs during 2021?

A. Tampa Electric incurred incremental Optimization Mechanism personnel costs to establish processes and manage these new activities. However, the company agreed that it would not seek recovery of these costs through the Optimization Mechanism if it was approved and therefore has not separately tracked the costs.

Q. Overall, were Tampa Electric's activities under the Optimization Mechanism successful in 2021?

A. Yes, Tampa Electric produced customer gains of $8,619,866 in the fourth year of Optimization Mechanism activity. The company continues to focus on improvements in processes, reporting, and optimization strategies.

Despite another mild winter in the southeast United States in 2021, the impacts of Winter Storm Uri in February produced optimization opportunities. Gains of $2,691,992 or 20 percent of optimization gains were realized in production (upstream) area gas sales and gas storage utilization during this event. Similar to results in 2019 and 2020, economic wholesale power purchases were the largest contributor of gains with 65 percent of optimization gains. Wholesale power sales gains were driven by generation outage demand in September and October. Natural gas storage AMA gains were better than expected given the volatility in the gas market. Lastly, coal sales contributed solid fuel gains.

Q. Does this conclude your testimony?

A. Yes, it does.

TECO
TAMPA ELECTRIC
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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220001-EI
IN RE: TAMPA ELECTRIC'S
FUEL & PURCHASED POWER COST RECOVERY
AND CAPACITY COST RECOVERY

FUEL PROCUREMENT AND WHOLESALE POWER PURCHASES
RISK MANAGEMENT PLAN

JANUARY 2023 THROUGH DECEMBER 2023

TESTIMONY AND EXHIBIT
OF
JOHN C. HEISEY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOHN C. HEISEY

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

A. My name is John C. Heisey. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Origination and Trading.

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

A. I graduated from Pennsylvania State University with a Bachelor of Science in Business Logistics. I have over 26 years of power and natural gas trading experience, including employment at TECO Energy Source, FPL Energy Services, El Paso Energy, and International Paper. Prior to joining Tampa Electric, I was Vice President of Asset Trading for the Entegra Power Group, LLC ("Entegra") where I was responsible for Entegra's energy trading activities. Entegra managed a large quantity of merchant capacity in bilateral and organized markets. I joined

Tampa Electric in September 2016 as the Manager of Gas and Power Trading and currently hold that position. I am responsible for natural gas and power trading activities and work closely with the company's unit commitment team to provide low cost, reliable power to our customers. In addition, I am responsible for portfolio optimization and all aspects of the Optimization Mechanism.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor and describe Exhibit No. JCH-2, entitled Tampa Electric Company's Fuel Procurement and Wholesale Power Purchases Risk Management Plan 2023.

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

A. Yes, it was.

Q. Please describe your exhibit.

A. My Exhibit No. JCH-2 provides Tampa Electric's overall plan for mitigating risk in the company's procurement of fuel and purchased power during 2023.

Q. Is hedging activity included in Tampa Electric’s Risk Management Plan for 2023?

A. No. In accordance with the 2021 Amended and Restated Stipulation and Settlement Agreement (“2021 Agreement”), approved by Commission Order No. PSC-2021-0423-S-EI issued on November 10, 2021, in Docket No. 20210034-EI, the company agreed that it would not enter any new natural gas financial hedging contracts through December 31, 2024. Tampa Electric currently has no active natural gas hedges. In accordance with the 2021 Agreement, the company currently has no plans to engage in natural gas hedging activity.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOHN C. HEISEY

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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20220001-EI

FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

PROJECTIONS

JANUARY 2023 THROUGH DECEMBER 2023

TESTIMONY

OF

JOHN C. HEISEY

FILED: SEPTEMBER 2, 2022

TAMPA ELECTRIC COMPANY
DOCKET NO. 20220001-EI
FILED: 09/02/2022

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOHN C. HEISEY

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

A. My name is John C. Heisey. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Origination and Trading.

Q. Have you previously filed testimony in Docket No. 20220001-EI?

A. Yes, I submitted direct testimony on April 1, 2022 and July 27, 2022.

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

A. No, they have not.

Q. Please describe your duties and responsibilities in that position.

A. I am responsible for directing all activities associated with the procurement and delivery of energy commodities for Tampa Electric’s generation fleet. Such activities include the trading, optimization, strategy, planning, origination, compliance and regulatory oversight of natural gas, power, coal, oil, byproducts, and associated delivery. I am also responsible for all aspects of the Optimization Mechanism.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss Tampa Electric’s fuel mix, fuel price forecasts, potential impacts to fuel prices, and the company’s fuel procurement strategies.

Fuel Mix and Procurement Strategies

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

A. Tampa Electric’s generation portfolio includes natural gas, solar, coal, and, as a backup fuel, oil powered units. Big Bend Unit 3 operates on natural gas, and Big Bend Unit 4 can operate on coal or natural gas. Big Bend Modernization project’s first phase, Big Bend combustion turbine Units 5 and 6, operate on natural gas. The second phase of the Big Bend Modernization project includes the addition of the Heat Recovery Steam Generator ("HRSG") in December 2022 and will result in the unit's operation in combined cycle mode. Polk Unit 1 can operate on natural gas or a blend of petroleum coke and coal. Currently, the company is operating Polk Unit 1 on natural gas and Big Bend Unit 4 on coal. Polk Unit 2 combined cycle uses natural gas as a primary fuel and oil as a secondary fuel; and Bayside Station combined cycle units and the company's collection of peakers (*i.e.,* aero-derivative combustion turbines) all utilize natural gas. Since it serves as a backup fuel, oil consumption is primarily for testing, and oil is a negligible percentage of system generation. Based upon the 2022 actual-estimate projections, the company expects 2022 total system generation, excluding purchased power, to be 85 percent natural gas, 9 percent solar, and 6 percent coal.

Likewise, in 2023, natural gas-fired and solar generation are expected to be 84 percent and 11 percent of total generation, respectively, with coal-fired generation making up 5 percent of total generation.

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

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

Natural Gas Supply Strategy

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

A. Tampa Electric uses a portfolio approach to natural gas procurement. This approach consists of a blend of pre-arranged base, intermediate, and swing natural gas supply contracts complemented with shorter term spot and seasonal purchases. The contracts have various time lengths to help secure needed supply at competitive prices while maintaining the flexibility to adapt to any changing fuel needs. Tampa Electric purchases its physical natural gas supply from creditworthy counterparties, enhancing the liquidity and diversification of its natural gas supply portfolio. Tampa Electric targets natural gas supply that is reliable and resistant to the impacts of extreme weather. The natural gas prices are based on monthly and daily price indices, further increasing pricing diversification.

Tampa Electric diversifies its pipeline transportation assets, including receipt points. The company also utilizes pipeline and storage services to enhance access to natural gas supply during hurricanes, extreme weather or other events that constrain supply. Such actions improve the reliability and cost-effectiveness of the physical delivery of natural gas to the company’s power plants. Furthermore, Tampa Electric strives daily to obtain reliable supplies of natural gas at favorable prices to mitigate costs for its customers.

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

A. Tampa Electric currently receives natural gas directly via the Florida Gas Transmission (“FGT”) and Gulfstream

Natural Gas System, LLC ("Gulfstream") pipelines. Tampa Electric also receives a portion of its gas via the recently constructed Sabal Trail Transmission ("Sabal Trail") gas pipeline (via Gulfstream backhaul). The ability to deliver natural gas from three pipelines increases the fuel delivery reliability for Bayside Power Station, which is composed of two large natural gas combined-cycle units and four aero-derivative combustion turbines. Natural gas can also be delivered to Big Bend Station from Gulfstream and Sabal Trail to support the station's steam generating units, aero-derivative combustion turbine, and upcoming Big Bend Modernization project. Later this year, the second and final phase of a new gas pipeline lateral will be completed that allows natural gas to be delivered to the Big Bend Station from FGT. This lateral increases the fuel delivery reliability for Big Bend Station. Polk Station receives natural gas from FGT to support natural gas consumption in Polk Units 1 and 2.

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

A. Tampa Electric's natural gas usage is expected to slightly decrease in 2023 when compared to 2022. Additional solar generation, the retirement of Big Bend Unit 3, and the combined cycle operation at the efficient Big Bend Modernization project will result in a reduction in natural gas usage in the period.

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

A. Tampa Electric maintains natural gas storage capacity with Bay Gas Storage near Mobile, Alabama, and Southern Pines Energy Center in Eastern Mississippi to provide operational flexibility and reliability of natural gas supply. The company reserves 2,000,000 MMBtu of long-term storage capacity in these two locations. This storage was used during Storm Uri in February 2021 to replace interrupted supply and to mitigate costs for our customers. Storage was also utilized this summer to help mitigate the risk of southeast gas basis premiums.

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

Tampa Electric also reserves capacity on the Southeast Supply Header ("SESH"), Gulf South pipeline ("Gulf South"), and Transco's Mobile Bay Lateral ("Transco"). SESH, Gulf South, and Transco connect the receipt points of FGT, Gulfstream, and other Mobile Bay area pipelines with natural gas supply in the mid-continent and northeast. Mid-continent and northeast natural gas production, specifically shale production, has grown and continues to increase. Thus, SESH, Gulf South, and Transco capacity give Tampa Electric access to secure, competitively priced onshore gas supply for a portion of its portfolio. Tampa Electric continuously evaluates its gas transportation portfolio based on changing market conditions to ensure access to reliable natural gas supply. All receipt points in the portfolio are reviewed annually to ensure access to reliable supply basins.

Q. Has Tampa Electric acquired additional natural gas transportation for 2022 and 2023 due to greater use of natural gas?

A. Yes. In 2022, Tampa Electric acquired short-term capacity on FGT in January and February to increase the reliability of the portfolio for its projected winter peak. In addition, power purchases were executed for January and

February as a lower cost solution compared to acquiring additional short-term pipeline capacity, as mentioned in the testimony of Tampa Electric witness Benjamin F. Smith, II. In the summer of 2022, Tampa Electric acquired additional short-term pipeline capacity on FGT. This capacity provides additional transportation for the portfolio to support higher gas burns over the summer as well as increasing the reliability of the portfolio for its projected winter peak in 2023. At the end of 2022, Tampa Electric will replace its Sabal Trail capacity with Gulfstream capacity to supply the Big Bend Modernization project and other portfolio gas requirements. For 2023, Tampa Electric has acquired additional capacity on FGT. This capacity provides additional transportation for the portfolio as Tampa Electric continues to transition from coal-fired generation to cleaner burning natural gas-fired generation.

Coal Supply Strategy

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

A. As with its natural gas strategy, Tampa Electric uses a portfolio approach to coal procurement. Big Bend Unit 4 is designed to burn high-sulfur Illinois Basin coal and is fully scrubbed for sulfur dioxide and nitrogen oxides, and the unit has been upgraded to operate on natural gas. Polk Unit 1 can burn a blend of petroleum coke and low sulfur coal, or natural gas. Each plant has varying operational and environmental restrictions and requires solid fuel with custom quality characteristics such as ash content, fusion temperature, sulfur content, heat content, and chlorine content.

Coal is not a homogenous product. The fuel’s chemistry and contents vary based on many factors, including geography. The variability of the product dictates that Tampa Electric select its fuel based on multiple parameters. Those parameters include unique coal quality characteristics, price, availability, deliverability, and creditworthiness of the supplier.

To minimize costs, maintain operational flexibility, and ensure reliable supply, Tampa Electric typically maintains a portfolio of bilateral coal supply contracts with varying term lengths. Tampa Electric monitors the market to obtain the most favorable prices from sources that meet the needs of the generation stations. The use of daily and weekly publications, independent research analyses from industry experts, discussions with suppliers, and coal solicitations aid the company in monitoring the coal market. This market intelligence also helps shape the company's coal procurement strategy to reflect short- and long-term market conditions. Tampa Electric's strategy provides a stable supply of reliable fuel sources. In addition, this strategy allows the company the flexibility to take advantage of favorable spot market opportunities and address operational needs.

Q. Please summarize how Tampa Electric will manage its solid fuel supply contracts through 2023.

A. Due to an event at an Illinois Basin mine last year that suspended mining operations for approximately six months, Tampa Electric has been managing supply interruptions and lower than projected solid fuel inventories for the last year. As domestic and international demand for coal has increased over the same period, we expect tight supply conditions to continue for the balance of the year and into 2023. Tampa Electric will supply the Big Bend and Polk Stations with solid fuel through a combination of existing inventory, short-term contracts, and, as necessary, spot purchases in support of the most economic commitment and dispatch for the generation fleet. Short-term and spot purchases allow the company to adjust supply to reflect changing coal quality and quantity needs, operational changes, and pricing opportunities.

Coal Transportation

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

A. Tampa Electric can receive coal at its Big Bend Station via waterborne or rail delivery. Once delivered to Big Bend Station, solid fuel is consumed onsite, or blended and trucked to Polk Station for consumption in Polk Unit 1. As a result of declining solid fuel burns over the last few years, Tampa Electric now purchases delivered coal, where waterborne coal supply and transportation are arranged by the supplier. Procuring delivered waterborne coal continues to provide customers with competitive coal prices through a simplified process. Commodity and transportation of coal by rail is still being arranged separately, as necessary.

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

A. Bimodal solid fuel transportation to Big Bend Station affords the company and its customers various benefits. Those benefits include 1) access to more potential coal suppliers, which results in a more competitively priced, and diverse, delivered coal portfolio; 2) the opportunity to switch to either water or rail in the event of a transportation breakdown or interruption on the other mode; and 3) competition among transporters for future solid fuel transportation contracts. The benefits of bimodal solid fuel transportation were apparent in 2022 as coal deliveries by rail were not reliable due to labor shortages in the rail industry.

Q. Will Tampa Electric continue to receive coal deliveries via rail in 2022 and 2023?

A. Yes. Although we experienced supply and transport challenges this year, Tampa Electric expects to receive coal for use at Big Bend Station through the Big Bend rail facility during 2022 and is evaluating how much coal to receive by rail in 2023.

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

A. Tampa Electric expects to receive the majority of its solid fuel supply in 2023 from waterborne deliveries to its unloading facilities at Big Bend Station. These deliveries come via the Mississippi River System or from foreign sources. The ultimate supply source is dependent upon quality, operational needs, and lowest overall delivered cost.

Q. Do you have any other updates to provide regarding Tampa Electric's solid fuel transportation portfolio?

A. Yes. Tampa Electric continues to burn natural gas as the economic fuel in Polk Unit 1. Big Bend Unit 4 is projected to burn coal in 2023. Although coal consumption has decreased relative to previous years, the expected coal burn in 2023 will be similar to 2022.

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

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

Q. Are there any other pertinent aspects of how Tampa Electric manages its fuel supply portfolio?

A. Yes. As part of Tampa Electric’s 2017 Amended and Restated Stipulation and Settlement Agreement approved by Commission Order No. PSC-2017-0456-S-EI, issued on November 27, 2017 in Docket No. 20170210-EI, and extended by the 2021 Stipulation and Settlement Agreement approved by Order No. PSC-2021-0423-S-EI issued on November 10, 2021 in Docket No. 20210034-EI, Tampa Electric has been operating under an Asset Optimization Mechanism since January 1, 2018. This Optimization Mechanism encourages Tampa Electric to market temporarily unused fuel supply assets to capture cost mitigation benefits for customers. These benefits have come through economic power purchases, economic power sales, resale of unneeded fuel supply, an asset management agreement for natural gas storage, and utilization of natural gas and solid fuel storage and transportation assets.

Projected 2023 Fuel Prices

Q. How does Tampa Electric project fuel prices?

A. Tampa Electric reviews fuel price forecasts from sources widely used in the industry, including the New York Mercantile Exchange ("NYMEX"), S&P Scenario Planning Service Annual Guidebook (originally produced by PIRA Energy Group), the Energy Information Administration, and other energy market information sources. Future prices for energy commodities as traded on NYMEX, averaged over five consecutive business days ending August 1, 2022, form the basis of the natural gas and No. 2 oil market commodity price forecasts. The price projections for these two commodities are then adjusted to incorporate expected transportation costs and location differences.

Coal commodity and transportation prices are projected using contracted pricing and information from industry recognized consultants and published indices, such as IHS Markit and Argus *Coal Daily*. Also, the price projections are specific to the quality and mined location of coal utilized by Tampa Electric's Big Bend Unit 4 and Polk Unit 1. Final as-burned prices are derived using expected commodity prices and associated transportation costs.

Q. How do the 2023 projected fuel prices compare to the fuel prices projected for 2022 in the company's mid-course correction filing?

A. Demand for natural gas in 2022 continued to outpace supply. Forward prices remain elevated through March 2023 and then decline as production is expected to increase into 2023 to balance the market. Higher gas demand is driven by LNG exports, low coal inventories, extreme summer weather, and low storage inventories. Production growth has been very slow as producers exercise capital discipline despite rising gas prices. In addition, the Ukraine invasion continues to impact the energy markets through increased volatility and uncertainty, which is expected to continue into 2023.

The commodity price for natural gas during 2023 is projected to be higher ($5.74 per MMBtu) than the 2022 price ($3.73 per MMBtu) projected in the company's mid-course correction fuel filing. The 2023 delivered coal price projection is higher ($90.57 per ton) than the price projected for 2022 ($84.55 per ton) during preparation of the 2022 mid-course correction fuel clause factors.

Q. Does this conclude your direct testimony?

A. Yes.

CHAIRMAN FAY: And then next we will move on to exhibits.

MS. BROWNLESS: Yes. Thank you.

CHAIRMAN FAY: Okay.

MS. BROWNLESS: Staff has compiled a stipulated Comprehensive Exhibit List which includes the prefiled exhibits attached to the witnesses' testimony as we've limited those previously, as well as Staff's Exhibit 38 through 69. The list has been provided to the parties, the Commissioners and the court reporter.

At this time, staff requests that the Comprehensive Exhibit List be marked for identification purposes as Exhibit No. 1, and that the other exhibits be marked for identification as set forth in the Comprehensive Exhibit List.

CHAIRMAN FAY: Okay. Show those exhibits marked.

(Whereupon, Exhibit Nos. 1 - 69 were marked for identification.)

MS. BROWNLESS: We would, at this time, request that the Comprehensive Exhibit List be entered into the record. You have just done that -- or, I am sorry --

CHAIRMAN FAY: No, we need to --

MS. BROWNLESS: We need to enter it into the record. Excuse me.

CHAIRMAN FAY: That's all right. We will enter Exhibit 1 into the record without objection.

(Whereupon, Exhibit No. 1 was received into evident.)

MS. BROWNLESS: Okay. Yesterday FPUC advised staff that it wished to correct its response to Staff's Fourth Set of Interrogatories No. 5, which has been included in the Comprehensive Exhibit List as Exhibit 53. OPC has provided staff and all parties with a line and strike version of its response. Staff proposes to substitute this version of Exhibit 53 into the record.

We have copies of Revised Exhibit 53 available if the parties failed to receive the exhibit emailed to them last night. And we would like to know if any party has a problem with substituting this version.

CHAIRMAN FAY: Okay. Just confirmation, the parties have received this version? No objections? Okay.

MR. REHWINKEL: You said OPC, but you meant FPUC, right?

MS. BROWNLESS: Oh, I am sorry. Excuse me.

CHAIRMAN FAY: All right. So without objection, show that entered.

MS. BROWNLESS: We would request at this time that stipulated Staff Exhibits Nos. 38 through 69 be entered into the record.

CHAIRMAN FAY: Okay. Without objection, show Staff's Exhibits 38 through 69 entered into the record.

(Whereupon, Exhibit Nos. 38 - 69 were received into evident.)

MS. BROWNLESS: Okay. The exhibits that have been agreed to by the parties in addition to the staff exhibits are Nos. 8 through 21 and 25 through 37.

CHAIRMAN FAY: Okay.

MS. BROWNLESS: So we would ask at this time that those be placed in the record.

CHAIRMAN FAY: Okay. Parties have any objections to those being placed in the record? No.

Okay. So with that, hearing no objections, we will enter in Exhibits 8 through 21 and 25 through 37 into the record.

(Whereupon, Exhibit Nos. 8-21 & 25-37 were received into evidence.)

CHAIRMAN FAY: I think that takes care of exhibits, Ms. Brownless.

MS. BROWNLESS: Yes, sir.

CHAIRMAN FAY: Okay. Great.

All right. Next we will move into opening statements for the 01 docket. So as consistent with the Prehearing Order, each party is allotted five minutes for the opening statements. I will confirm if Nucor or any of the other parties want to waive that opening statement, now would be the time to let me know, and then we will go through the appropriate order to the utilities and the intervenors.

MR. BRISCAR: We will have a brief statement.

CHAIRMAN FAY: You will have a brief statement?

MR. BRISCAR: Yes.

CHAIRMAN FAY: Okay. Any other waivers? Mr. Moyle.

MR. MOYLE: No, I just --

CHAIRMAN FAY: You are waiving?

MR. MOYLE: No. No. No.

CHAIRMAN FAY: Okay. Sorry. Go ahead.

MR. MOYLE: I just was trying to keenly listen to understand whether the Type 2 stipulations had been accepted by the Commission. I don't think I heard that.

CHAIRMAN FAY: Not yet.

MR. MOYLE: Okay. But that's on the -- that's going to happen?

CHAIRMAN FAY: After opening statements, we will take up the stipulated, which was a different order than previously.

MR. MOYLE: Okay.

CHAIRMAN FAY: Okay. With that, then, we will -- Ms. Keating, yes.

MS. KEATING: I was actually going to say that FPUC will waive opening statement.

CHAIRMAN FAY: Okay. All right. With that, we will move to the utilities. We will start with Duke.

MR. BERNIER: We will waive opening.

Thank you.

CHAIRMAN FAY: Okay. FPL, you are recognized, Ms. Moncada.

MS. MONCADA: Thank you. Good afternoon again, Mr. Chairman and Commissioners.

It's not a common occurrence that FPL or other utilities deliver remarks regarding fuel commodity costs. Most of the time the calculations, at least as to commodity costs, are straightforward. This year has been very different.

On February 24th, Russia invaded Ukraine. That geopolitical development, along with other domestic and international factors, impacted the 2022 natural gas market in ways that we have not seen in many years.

On April 15th, FPL notified the Commission that it projected an under-recovery greater than 10 percent for 2022, but that filing a midcourse correction at that time was not practical. Due to forces sharply impacting the natural gas prices, we believe believed it was more appropriate to continue to monitor the market to see if prices might moderate.

Three months later, on July 27th, FPL submitted its actual estimated filing, which included a calculation of our under-recovery based on actuals through June, and a revised estimate for July through December. And that was based on a June 21st NYMEX curve. At that time, the 2022 under-recovery was estimated to be $1.66 billion.

FPL's filing noted that in the intervening months between April and July, the natural gas market conditions grew even more volatile and, therefore, we continued to believe it was appropriate to keep monitoring market conditions. We notified the Commission of two things. First, that FPL would not seek collection of any portion of the under-recovery during the 2022 calendar year. And second, that we would not seek to include any portion of the 2022 under-recovery during this November hearing for the factor that will become effective on January 1st.

Finally, on September 2nd, FPL submitted the fuel costs it is requesting to include in the January 2023 factor that we are asking you to approve as part of this proceeding. The testimony of Scott Bores explained that the gas market volatility persisted, and he confirmed that we excluded from the fuel factor FPL's 2022 under-recovery.

The extreme volatility made it more appropriate to gather additional months of actual data to develop the costs that will be used to calculate the 2022 under-recovery, and to inform our decision regarding the period of time over which we will seek recovery.

In sum, Commissioners, 2022 has seen extraordinary volatility in terms of both duration, as well as the magnitude in the swing of the prices for natural gas. Throughout the year, there was no point in time when it was practical to take a snapshot of our forecasted under-recovery.

Finally, I will take just a moment to address OPC's standing objection. OPC claims this is an illegal proceeding. FPL disagrees, and we can address the finer points of that at a later time. But I would like to at least point out that if OPC believed there was an infirmity, they could have asked for a legal issue to be raised in this docket. They could have included it in the Prehearing Order. They did not. And there is no reason why they could not have given the chronology I have just laid out of when FPL has made the Commission and all the parties aware of its plan to exclude the 2022 amount from the fuel factor that will be implemented starting January 1.

Given the factual circumstances regarding the extraordinary market we experienced this year, FPL should be permitted to exclude the 2022 estimated under-recovery amount from the factor to be implemented starting January 1, and should be permitted to file for recovery in January a plan for the recovery that includes actuals and also a plan for the amount of time over which it will be collected.

Thank you for the opportunity to deliver an opening statement. FPL witnesses Gerard Yupp and Scott Bores will be here to address questions this afternoon, or maybe tomorrow morning, depending on how things go.

CHAIRMAN FAY: Okay. We will have them hang around for both, this afternoon and tomorrow morning. We will see where we land.

With that, next I have TECO. Mr. Means.

MR. MEANS: Thank you, Mr. Chairman, and good afternoon, Commissioners.

Today, Tampa Electric seeks your approval of the company's proposed fuel and purchase power cost recovery factors and capacity cost recovery factors for 2023. These factors are reasonable and were prepared in accordance with Commission guidance and precedent.

Today you have already heard arguments and questions from the other parties regarding Tampa Electric's projected under-recovery of fuel costs for 2022. We have a witness here today, Ms. Penelope Rusk, who is available to answer questions regarding that subject.

And I will just conclude by saying that we are in the same posture as is Florida Power & Light, and I won't repeat any of the excellent points made by Ms. Moncada, so I will just conclude by asking you to approve our factors as filed.

Thank you.

CHAIRMAN FAY: Thank you, Mr. Means.

Next we have OPC.

MR. REHWINKEL: I waive.

CHAIRMAN FAY: You waive for the original? Okay.

Mr. Moyle. FIPUG.

MR. MOYLE: Well, thank you. And during the discussion with respect to the motion for reconsideration, we foreshadowed what FIPUG is interested in, which is the costs that FIPUG members and other utility customers are going to have to pay in the upcoming calendars year, which starts shortly. We will be asking questions along those lines designed to try to get information so people can understand what that is, and put together budgets and plan accordingly.

I just fundamentally don't think it's fair to tell people you got -- you got a big issue coming, but not provide information as to the order of magnitude. And I was just thinking, you know, when you are buying something, buying a car, buying a house, renting a house, buying a piece of equipment for a business, you know, you usually can ascertain what the cost of those things will be. You know, that's how markets are. But we are in an unusual situation now where we don't really have with certainty what those costs are going to be, and over what period of time we are going to be looked to to provide those monies.

So a little bit of a comment with respect to, you know, natural -- natural gas. I mean, that's the prime -- primary fuel that the fleets in Florida are -- are running on. As you all know, you know, 65, 70 percent of the generation mix is natural gas fired. And natural gas markets, like other markets, you know, they move around.

This market has been volatile. It's moved around, but I think if you went back through a long history, you would find other periods of time where natural gas prices have, you know, have gone up. Probably, I think, more than they have now.

Commissioner Clark, you have been in this business a long time, and I believe there were some -- some teens, where natural gas was in the teens for a unit that has been in double digits. I think it's down in single digits now. But it's an important piece of information, this natural gas hearing, with respect to what people are going to be confronted with with regard to their electric bills in the upcoming fiscal year.

And, again, this conversation is just about natural gas, but as you all know, there are a variety of other charges that are going to be coming in on January 1st, 2023.

There is rate case -- rate cases that have been settled that have rate increases flowing in. Today you all took action an environmental cost recovery clause and also the storm protection clause. Those are going to result in increased rates. And the natural gas, the fuel clause is going to result in increased rates. And again, we would request that we be provided latitude and the ability to understand fully what -- what those costs are going to look like.

And I think FIPUG, just to let you know, we will be asking questions about the dollar amounts, but also what percentage increase does that represent with respect to the fuel clause, and try to get information that will give people a good understanding of the magnitude of the increases that are being contemplated.

So thanks for the chance to share those thoughts.

CHAIRMAN FAY: Great. Thank you, Mr. Moyle.

Mr. Wright.

MR. WRIGHT: Excuse me. Thank you very much, Mr. Chairman.

Commissioners, y'all have long followed what us rate geeks call the matching principle, and that is cost causers should pay, costs should be recovered as costs are incurred. You will hear a little bit more about this later, but here's a paraphrase of one articulation of that: The people who incurred the costs are the people who should pay them.

Another articulation is that the purpose of the fuel docket is that the -- is the matching of fuel expenditures as revenues as they -- and revenues as they are being incurred.

This is a sound principle of ratemaking. Costs should match rates. Utilities have not followed this here.

The proposition that rates have been -- that gas price versus been volatile is certainly true, but the volatility does not outweigh the appropriateness of applying the matching principle for rate recovery of the costs that are incurred.

Utilities have allowed the -- their 2022 cost under-recoveries, fuel costs under-recoveries to snowball egregiously. There is no other word for it -- there is a bunch more, but that's a good one, you know, 3.3 billion, $3.4 billion.

The information regarding these costs under-recoveries either is or will be -- much of it is in the record already with the prefiled exhibits coming in -- much of it is in the record, additionally, some of it will be in the record all taken from utility filings.

You, the Florida Public Service Commission, can act on this information. We, the Retail Federation representing customers, will ask you to take action to at least require the utilities to start recovering some of this beginning in January.

Thank you very much.

CHAIRMAN FAY: Thank you, Mr. Wright.

Let's see, Mr. Brew?

MR. BREW: Thank you, Mr. Chairman.

This will be a little bit more adamant version of what Mr. Moyle was talking about.

In my roughly 43 years in this field, this is the most bizarre circumstance I can recall running into. In Duke's case, they are proposing a 37 percent increase in their jurisdictional fuel cost factor. And as much as that is a stinging budget buster for businesses and consumers throughout their territory, we can all read. It's right there in the exhibits. The final factors we are eventually going to pay next year are much, much higher. We just don't know what they are. And that's what the purpose of this proceeding is supposed to establish.

There are several problems here for the Commission and consumers about what to do in this odd circumstance, and I am not just referring to the seemingly incongruous position of consumers asking for their factor to go up higher than what the utility has proposed.

In -- in this case with Duke, their -- and we will get into this obviously in the testimony, but their projected 2022 under-recovery is over $1,300,000,000, of which they propose to recover some of it, about 14 percent, leaving 85 percent, or 1.1 billion hanging.

Now that is saying something given that Duke's total fuel budget is 2.4. So you have got an under-recovery that's half as big as the total budget. This is not an issue that can be ignored.

I am not aware of any testimony arguing that they incurred costs imprudently. Nobody is blaming them for underlying commodity costs going up, but it's a hole that can't be ignored. And as bad news as the rising fuel costs are for Florida businesses and consumers, failing to address that under-recovery when you have got solid information, and the fact is you do have solid information from '22 -- 2022 now, is a disservice to everybody.

And just in terms of the record, Duke reported an actual under-recovery of $750 million in July through June, and they projected it was going to get worse by almost half again to get up to the 1.3 billion. When they filed in September, the numbers didn't change. It's still 1.3 billion. The exhibits are exactly the same. They had information to -- sufficient to show that there was no amount of reduction in the underlying cost of fuels that was going to offset this.

We are going to have to deal with it. As consumers, we know that. And pushing it out into a period where we don't know how much more that factor is going to be for next year is unacceptable. You can't run a business that way if you are your fuel budget might be off by millions of dollars. How do you run a household if your bill is going to be off by a couple of hundred dollars a month? The whole purpose of this proceeding is to pin that down, and we are going to ask that the Commission do that.

At least, in the case of Duke, they need to include some or all of at least the known actual $750 million in the factor beginning in January, and then we can talk about the other issues. To just put a tiny piece in and leave it for a future filing of unknown recovery period, where -- and compressing the recovery over less than 12 months, would have dramatic impacts even further.

So there is no way that we can address these issues without adding them up and getting to what the real bill impacts are. The process here, which Mr. Rehwinkel described, doesn't get us to where the information that the Commission needs to get to, and we are going to ask that you do so.

Thank you.

CHAIRMAN FAY: Thank you, Mr. Brew.

Nucor, you are recognized.

MR. BRISCAR: Good afternoon, Commissioners. Joseph Briscar for Nucor.

I think the other intervenors have mostly addressed the issues I want to address, so I will be brief.

Duke proposes to raise rates in this proceeding to recover approximately $175 million in additional revenues. However, that still leaves over one billion in under-recovered costs that Duke will seek to recover at some point in the future. Duke's plan leaves customers in the dark.

Businesses need information on costs to successfully budget their operations. All we know is that we can maybe expect rates to increase at some time next year to begin to recover the roughly $1 billion in under-recovered fuel costs.

We ask that the Commission be mindful of the remaining under-recovery balance. And if the Commission deems it prudent, direct Duke to work with stakeholders and businesses to reach a reasonable compromise on how to recover the under-recovery balance prior to filing any midcourse correction.

Thank you.

CHAIRMAN FAY: All right. That concludes our opening statements. Next we will move into the stipulated issues.

Ms. Brownless, if you want to go ahead and, I guess, by each utility, we will lay out the Type 2 stipulations. And then I would just ask the utilities and the intervenors just to make sure she goes through these that were inclusive of what you believe is included in there. And then, if we are missing anything, we will make sure we make the corrections at this time.

So, Ms. Brownless, you are recognized. Thank you.

MS. BROWNLESS: Yes, sir.

As we understand it, the Type 2 stipulations for Duke are 1A through 1G, 5 through 7, 14, 15, 17, 19, 21A through 21C, 24 through 30, 31 through 33.

For FPL, the stipulated issues are 2A through 2F, 5 through 7, 14, 15, 17, 19, 24 through 30, 31 through 33.

For FPUC, the issues are 7, 8, 9, 10, 16 through 20, 31 through 33.

For TECO, the stipulated issues are 4A through 4C, 5 through 7, 14, 15, 17, 19, 24 through 30 and 31 through 33.

At this time, we would request that the Commissioners accept these stipulations, and we are available to answer any questions.

CHAIRMAN FAY: Okay. Great.

Before I go to my colleagues for any questions or discussion, let me make sure with the parties that those are accurate stipulations.

Mr. Moyle, is that correct?

MR. MOYLE: I believe so. I -- just in terms of the document that you are going to act on them, I am not sure I have that, or have seen that.

MS. BROWNLESS: You were provided the proposed stipulations. They were emailed, but we also have them available, and they are in the CEL as Exhibit No. 68.

MR. MOYLE: Okay.

CHAIRMAN FAY: Okay. You are good?

MR. MOYLE: I will check on the break.

CHAIRMAN FAY: Okay. With that, Mr. Moyle, the Commission will move forward for them, but if there is a correction that we need to make post your review, please let the Commission know and we will make sure that if we've got a numbering issue or something, we can address it.

So with that, Commissioners, if you have questions for staff or discussion on those issues? If not, we can take a motion on the stipulated issues, the Type 2 stipulations as provided by Ms. -- the list provided by Ms. Brownless.

COMMISSIONER CLARK: Move to approve the stipulations, Mr. Chairman.

CHAIRMAN FAY: Okay. We have a motion. Do we have a second?

COMMISSIONER GRAHAM: Second.

CHAIRMAN FAY: Okay. We have a motion and a second to approve the Type 2 stipulations for Duke, FPL, FPUC and TECO.

All that approve say aye.

(Chorus of ayes.)

MS. PASSIDOMO: Aye.

CHAIRMAN FAY: None opposed.

With that, show the Type 2 stipulations as stated by Ms. Brownless approved.

Next we will move into witness testimony. Let me check and see for -- we have Duke Witness Dean, that would be the first witness up. OPC and intervenors, do you know what sort of time you would have on Witness Dean that you think reasonably we could estimate? And I am not rushing you. I am just trying to get an idea of our timing.

MR. REHWINKEL: I think I have an hour.

CHAIRMAN FAY: Okay.

MR. REHWINKEL: I'm not entirely positive, but yeah, at least.

CHAIRMAN FAY: Okay. Well, why don't we do this, then, because we are coming up on five o'clock. We will begin tomorrow at 9:30, and we will begin taking up the witnesses.

My plan for scheduling tomorrow, because I know we probably have witnesses and folks who are traveling, we will get through that, barring something unusual, by lunch, and then take up time for legal counsel to provide either closing arguments and/or set timelines for briefs to be provided at that time, and then the Commission will decide if we will make a decision as a bench or look for a more formal recommendation.

So hopefully that helps for planning purposes for our witnesses for tomorrow morning. Let me make sure --

MR. REHWINKEL: Would it make sense, Mr. Chairman, to introduce him and let him give his summary in the time between 5:00?

CHAIRMAN FAY: So you can plot about your cross after? I don't know. That seems --

MR. REHWINKEL: My cross isn't based on anything he is going to say in his summary.

CHAIRMAN FAY: I don't have an issue with that, Mr. Rehwinkel. I am not sure those few minutes are going to save us operationally, but Mr. Dean seems to be in the chair already and ready to go, so let me check. Ms. Brownless --

MS. BROWNLESS: I am sorry, I was dealing with something else and I didn't hear that.

CHAIRMAN FAY: That's okay. So -- so we are just in the current posture that we will take up the witnesses tomorrow. We were going to allow Mr. Dean, because he is super excited to be here, that he could provide his initial summary of his testimony --

MS. BROWNLESS: Oh, sure.

CHAIRMAN FAY: -- assuming Duke wasn't going to waive that part, and then we would move into the witnesses that --

MR. BERNIER: We are going to waive.

CHAIRMAN FAY: You are going to waive it, aren't you?

MR. BERNIER: We are going to waive.

MR. REHWINKEL: Okay.

CHAIRMAN FAY: Okay. Yeah. So with that said, then --

MR. REHWINKEL: I do have one preliminary matter we could take care of and save a little bit of time.

CHAIRMAN FAY: Okay. So with that, let me just -- let me close this out.

So, Mr. Dean, what we will do tomorrow morning is take you up, even though Mr. Bernier has stated that you will be waiving your -- we will take up the proper procedure for having you and make sure are make sure everybody is sworn in for the hearing tomorrow, and then take up your cross-examination if you are not providing a summary of your testimony. So you are off the hook today is what that means, but we will -- we will see you again tomorrow morning.

I wanted to make sure the parties didn't have any other matters. I know Mr. Rehwinkel does have one preliminary matter, I guess -- well, it's no longer preliminary, I guess, but maybe another matter to address the Commission. So with that, Mr. Rehwinkel, I will recognize you.

MR. REHWINKEL: Just a housekeeping thing.

I distributed by email to the parties

yesterday three exhibits that I intend to use in cross with various witnesses, and I have -- I have got paper copies, but I was just wondering if we could just go ahead and give them numbers and we can save time with that tomorrow if you wanted to do that.

CHAIRMAN FAY: Okay. Let's do that tomorrow just so then our folks don't have to hand out all those exhibits to us at this time to get them numbered and then we would be potentially leaving them and turning them back in, so -- but just to clarify, Mr. Rehwinkel, our team does have all of those exhibits --

MS. BROWNLESS: Yes.

CHAIRMAN FAY: -- so when we begin tomorrow, just for cross, to make sure when we have that witness come up, if you can make sure the Commission is provided those. And just also on the operational end, if Commissioner Passidomo is unable to physically be here, please make sure subject to check with her office so she will have copies available to her as cross occurs from the intervenors, so thank you for that.

With that, Commissioners, we will adjourn for today. We will see you at 9:30 a.m. tomorrow morning to begin witness testimony.

Thank you.

(Transcript continues in sequence in Volume 3.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

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

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

DATED this 28th day of November, 2022.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
EXPIRES AUGUST 13, 2024