

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: DOCKET NO. 20250001-EI
Fuel and Purchased Power Cost
Recovery Clause and Generating
Performance Incentive Factor

VOLUME 1
PAGES 1 - 290

PROCEEDINGS: HEARING

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

DATE: Tuesday, November 4, 2025

TIME: Commenced: 11:45 a.m.
Concluded: 12:15 p.m.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

PREMIER REPORTING
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24

25

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1 P R O C E E D I N G S

2 CHAIRMAN LA ROSA: Then let's go ahead and
3 adjourn from this docket and let's move into 01.

4 MR. SANDY: Good afternoon, Commissioners,
5 Ryan Sandy on behalf of the Office of General
6 Counsel for the 01 docket. There are several
7 preliminary matters to be discussed.

8 There are proposed Type 2 stipulations on all
9 issues in the clause docket. Those issue
10 stipulations are reflected in pages nine through 39
11 of the Prehearing Order. There are no objections
12 to those issue stipulations, therefore, you may
13 vote on them this afternoon.

14 All witnesses have been excused from the
15 proceeding, and their testimony and exhibits may be
16 entered into the record as though read when
17 appropriate.

18 And finally, all the parties have agreed to
19 waiving opening statements and post-hearing briefs.

20 CHAIRMAN LA ROSA: Great. Thank you.

21 Preliminary matters by the parties?

22 Seeing none, let's move, then, to prefiled
23 testimony.

24 MR. SANDY: Mr. Chair, staff asks that the
25 prefiled testimony of all the witnesses set forth

1 in Section 6 of the Prehearing Order is inserted
2 into the record as though read.

3 CHAIRMAN LA ROSA: All right. Then the
4 prefiled testimony of all the witnesses are entered
5 into the record as though read.

6 (Whereupon, prefiled direct testimony of Gary
7 P. Dean was inserted.)

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DUKE ENERGY FLORIDA, LLC

DOCKET No. 20250001-EI

**Fuel and Capacity Cost Recovery
Actual True-Up for the Period
January 2024 - December 2024**

DIRECT TESTIMONY OF

Gary P. Dean

April 2, 2025

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

2 A. My name is Gary P. Dean. My business address is 299 First Avenue North,
3 St. Petersburg, Florida 33701.

4

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

6 A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company"), as
7 Rates and Regulatory Strategy Manager.

8

9 **Q. What are your responsibilities in that position?**

10 A. I am responsible for regulatory planning and cost recovery for DEF. These
11 responsibilities include completion of regulatory financial reports and
12 analysis of local, state, and federal regulations and their impacts on DEF. In
13 this capacity, I am responsible for DEF's Final True-Up, Actual/Estimated
14 Projection, and Projection Filings in the Fuel Adjustment, Capacity Cost
15 Recovery, and Environmental Cost Recovery Clauses.

16

17 **Q. Please describe your educational background and professional**
18 **experience.**

1 A. I received a Master of Business Administration from Rutgers University and
2 a Bachelor of Science degree in Commerce and Engineering, majoring in
3 Finance, from Drexel University. I joined DEF on April 27, 2020, as the
4 Rates and Regulatory Strategy Manager. Prior to working at DEF, I was
5 the Senior Manager, Optimization for Chesapeake Utilities Corporation
6 ("CUC"). In this role, I was responsible for all pricing related to the
7 company's natural gas retail business. Prior to working at CUC, I was the
8 General Manager, Electric Operations for South Jersey Energy Company
9 ("SJEC"). In that capacity I held P&L and strategic development
10 responsibility for the company's electric retail book. Prior to working at
11 SJEC I had various positions associated with rates and regulatory affairs.
12 In these positions I was responsible for all rate and regulatory matters,
13 including tariff and rate design, financial modeling, and analysis, and
14 ensuring accurate rates for billing.

15
16 **Q. What is the purpose of your testimony?**

17 A. The purpose of my testimony is to provide DEF's Fuel Adjustment Clause
18 final true-up amount for the period of January 2024 through December 2024,
19 and DEF's Capacity Cost Recovery Clause final true-up amount for the same
20 period.

21
22 **Q. Have you prepared exhibits to your testimony?**

1 A. Yes, I have prepared and attached to my true-up testimony as Exhibit (GPD-
2 1T), a Fuel Adjustment Clause true-up calculation and related schedules;
3 Exhibit (GPD-2T), a Capacity Cost Recovery Clause true-up calculation and
4 related schedules; Exhibit (GPD-3T), Schedules A1 through A3, A6, and A12
5 for December 2024, year-to-date; Exhibit (GPD-4T), DEF's capital structure
6 and cost rates; and Exhibit (GPD-5T), DEF's Annual Clean Energy Impact
7 Program report. Schedules A1 through A9, and A12 for the year ended
8 December 31, 2024, were originally filed with the Commission on January
9 17, 2025.

10
11 **Q. What is the source of the data that you will present by way of testimony**
12 **or exhibits in this proceeding?**

13 A. Unless otherwise indicated, the actual data is taken from the books and
14 records of the Company. The books and records are kept in the regular
15 course of business in accordance with generally accepted accounting
16 principles and practices, provisions of the Uniform System of Accounts as
17 prescribed by the Federal Energy Regulatory Commission, and any
18 accounting rules and orders established by this Commission. The Company
19 relies on the information included in this testimony and exhibits in the conduct
20 of its affairs.

21
22 **Q. Would you please summarize your testimony?**

1 A. Per Order No. PSC-2024-0481-FOF-EI, the total estimated 2024 period
2 ending fuel over-recovery is \$8.5 million. The actual over-recovery for 2024
3 is \$84.2 million, resulting in a final fuel adjustment true-up over-recovery
4 amount of \$75.7 million. Exhibit No. (GPD-1T).

5
6 Per Order No. PSC-2024-0481-FOF-EI, the estimated 2024 capacity cost
7 recovery true-up amount was an under-recovery of \$6,798,946. The actual
8 capacity true-up amount for 2024 is an under-recovery of \$3,490,940,
9 resulting in a final capacity true-up over-recovery amount of \$3,308,006
10 million. Exhibit (GPD-2T).

11 12 FUEL COST RECOVERY

13 **Q. What is DEF's jurisdictional ending balance as of December 31, 2024,**
14 **for fuel cost recovery?**

15 A. The actual ending balance as of December 31, 2024, for true-up purposes is
16 an over-recovery of \$84,224,253, as shown on Exhibit (GPD-1T).

17
18 **Q. How does this amount compare to DEF's 2024 ending balance included**
19 **in the Company's September 5, 2024, Projection Filing?**

20 A. The actual true-up amount for the January 2024 - December 2024 period is
21 an over-recovery of \$84,224,253, which is \$75,686,464 greater than the year
22 end estimated over-recovery balance of \$8,537,789 included in DEF's

1 Projection filing approved by Order No. PSC-2024-0481-FOF-EI, as shown
2 on Exhibit (GPD-1T).

3
4 **Q. How was the final true-up ending balance determined?**

5 A. The amount was determined in the manner set forth on Schedule A2 of the
6 Commission's standard forms previously submitted by the Company monthly,
7 which included an update to reflect the True-Up WACC as prescribed in
8 Order No. PSC-2020-0165-PAA-EU.

9
10 **Q. What factors contributed to the increase of \$75,686,464 in the period-**
11 **ending jurisdictional net under-recovery shown on your Exhibit (GPD-**
12 **1T)?**

13 A. The \$75.7 million is driven primarily by decreased generation costs of \$79.0
14 million.

15
16 **Q. Please explain the components shown on Exhibit (GPD-1T), sheet 6 of**
17 **6, which helps to explain the \$62.5 million favorable system variance**
18 **from the actual-estimate projected cost of fuel and net purchased**
19 **power transactions.**

20 A. Exhibit (GPD-1T), sheet 6 of 6 is an analysis of the system dollar variance
21 for each energy source in terms of three interrelated components; (1)
22 changes in the amount (mWh's) of energy required; (2) changes in the
23 heat rate of generated energy (BTU's per kWh); and (3) changes in the

1 unit price of either fuel consumed for generation (\$ per million BTU) or energy
2 purchases and sales (cents per kWh). The \$62.5 million favorable system
3 variance is mainly attributable to lower coal and natural gas generation.
4

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

7 A. Yes. Noteworthy adjustments are shown on Exhibit (GPD-3T) in the footnote
8 to line 6b on page 1 of 2, Schedule A2. Consistent with Order No. PSC-2018-
9 0240-PAA-EQ, DEF included an adjustment of approximately \$11.811 million
10 system (\$11.806 million retail) for amortization of the Florida Power
11 Development, LLC, qualifying facility regulatory asset.
12

13 **Q. Did DEF make an adjustment for changes in coal inventory based on an**
14 **Aerial Survey?**

15 A. Yes. DEF included a \$7.9 million reduction to coal inventory attributable to
16 semi-annual aerial surveys conducted on May 6 and November 4, 2024, in
17 accordance with Order No. PSC-1997-0359-FOF-EI, Docket No. 19970001-
18 EI. This adjustment represents 5.0% of the total coal consumed at the Crystal
19 River facility in 2024.
20

21 **Q. Did DEF exceed the economy sales threshold in 2024?**

22 A. Yes. DEF did exceed the gain on economy sales threshold of \$3.8 million in
23 2024. As reported on Schedule A1-2, Line 11a, the gain for the year-to-date

1 period through December 2024 was \$4.5 million. Consistent with Order No.
2 PSC-2001-2371-FOF-EI, shareholders retain 20% of the gain in excess of
3 the three-year rolling average. For 2024, that amount is approximately \$0.1
4 million.

5
6 **Q. Has the three-year rolling average gain on economy sales been**
7 **updated?**

8 A. No. As authorized by FPSC Order No. PSC-2024-0472-AS-EI, DEF's Asset
9 Optimization Mechanism ("AOM") was approved, effective January 2025.
10 This approval provides for DEF to implement an AOM for the 2025 – 2027
11 period, and as a result the sharing mechanism applicable to economy sales
12 that was approved prior to DEF's AOM will not be applicable during the 2025
13 – 2027 period.

14 **CAPACITY COST RECOVERY**

15
16 **Q. What is the Company's jurisdictional ending balance as of December**
17 **31, 2024, for capacity cost recovery?**

18 A. The actual ending balance as of December 31, 2024, for true-up purposes is
19 an under-recovery of \$3,490,940, as shown on Exhibit (GPD-2T).

20
21 **Q. How does this amount compare to the estimated 2024 ending balance**
22 **included in the Company's Actual/Estimated Filing?**

1 A. When the estimated 2024 under-recovery of \$6,798,946 is compared to the
2 \$3,490,940 actual under-recovery, the final capacity true-up for the twelve-
3 month period ended December 2024 is an over-recovery of \$3,308,006, as
4 shown on Exhibit (GPD-2T).

5
6 **Q. Is this true-up calculation consistent with the true-up methodology**
7 **used for the other cost recovery clauses?**

8 A. Yes. The calculation of the final net true-up amount follows the procedures
9 established by the Commission.

10
11 **Q. What factors contributed to the actual period-end capacity over-**
12 **recovery of \$3.3 million?**

13 A. Exhibit (GPD-2T), sheet 1 of 3, compares actual results to the original
14 projection for the period. The \$3.3 million over-recovery is primarily due to
15 lower capacity costs, slightly offset by lower capacity revenue.

16
17 **OTHER MATTERS**

18
19 **Q. What capital structure and cost rates did DEF rely on to calculate the**
20 **revenue requirement rate of return for the period January 2024 through**
21 **December 2024?**

22 A. DEF used the capital structure and cost rates consistent with the language in
23 Order Nos. PSC-2020-0165-PAA-EU and PSC-2022-0357-FOF-EI. The

1 capital structure and cost rates relied on to calculate the revenue requirement
2 rate of return for the period January 2024 through December 2024 are shown
3 on Exhibit (GPD-4T).

4

5 **Q. Did DEF include its Clean Energy Impact annual program report as**
6 **prescribed by Order No. PSC-2023-0191-TRF-EI, dated June 29, 2024?**

7 A. Yes. As Ordered by the Commission, DEF has provided the annual report as
8 Exhibit (GPD-5T).

9

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

11 A. Yes.

DUKE ENERGY FLORIDA, LLC**DOCKET NO. 20250001-EI****Fuel and Capacity Cost Recovery
Actual/Estimated True-Up Amounts
January 2025 through December 2025****DIRECT TESTIMONY OF
GARY P. DEAN****July 25, 2025**

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

2 A. My name is Gary P. Dean. My business address is 299 1st Avenue North,
3 St. Petersburg, Florida 33701.

4

5 **Q. Have you previously filed testimony before this Commission in**
6 **Docket No. 20250001-EI?**

7 A. Yes. I provided direct testimony on April 2, 2025.

8

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

11 A. No.

12

13 **Q. What is the purpose of your testimony?**

14 A. The purpose of my testimony is to present for Commission approval the
15 actual/estimated fuel and capacity cost recovery true-up amounts of Duke

Energy Florida, LLC (“DEF” or the “Company”), for the period of January 2025 through December 2025.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared Exhibit No. (GPD-2), which is attached to my prepared testimony, consisting of two parts. Part 1 consists of Schedules E1-B through E9, which include the calculation of the 2025 actual/estimated fuel and purchased power true-up balance, a schedule to support the capital structure components and cost rates relied upon to calculate the return requirements on all capital projects recovered through the fuel clause and a schedule to support the calculation of the Hurricane Idalia over-recovery being credited to the fuel clause per Order No. PSC-2025-0204-FOF-EI. Part 2 consists of Schedules E12-A through E12-C, which include the calculation of the 2025 actual/estimated capacity true-up balance. The calculations in my exhibit are based on actual data from January through June 2025 and estimated data from July through December 2025.

FUEL COST RECOVERY

Q. What is the amount of DEF’s 2025 estimated fuel true-up balance and how was it developed?

A. DEF’s estimated fuel true-up balance is a \$47,145,198 under-recovery. The calculation begins with the actual over-recovered balance of

1 \$19,137,078 taken from Schedule E1-B, page 1 of 2, line 13, through the
2 month of June 2025. This balance plus the estimated July through
3 December 2025 monthly true-up calculations comprise the estimated
4 \$47,145,198 under-recovered balance at year-end. The projected
5 December 2025 true-up balance includes interest which is estimated from
6 July through December 2025 based on the average of the beginning and
7 ending commercial paper rate applied in June. That rate is 0.361% per
8 month.

9
10 **Q. How does the current forecast of fuel costs on Schedule E3 for July**
11 **through December 2025 compare with the same period forecast used**
12 **in the Company's 2025 Projection Filing approved in Order No. PSC-**
13 **2024-0481-FOF-EI?**

14 A. Light oil increased \$0.69/mmbtu (3%). Coal and natural gas increased
15 \$0.33/mmbtu (9%) and \$.31/mmbtu (6%), respectively.

16
17 **Q. Have any adjustments been made to estimated fuel costs for the**
18 **period January 2025 through December 2025?**

19 A. Yes. Consistent with Order No. PSC-2018-0240-PAA-EQ dated June 8,
20 2018, DEF included an adjustment of approximately \$11.3 million (grossed
21 up to approximately \$11.4 million from retail to system) for the amortization
22 of Florida Power Development, LLC qualifying facility regulatory asset
23 from January 2025 through December 2025. There was a coal inventory
24 adjustment of approximately \$2.9 million attributable to the semi-annual

1 aerial survey conducted on June 3, 2025, in accordance with Order No.
2 PSC-1997-0359-FOF-EI in Docket No. 1997001-EI. There was also an
3 approximate \$1.0 million in adjustments for net metering settlements.
4 These adjustments are included on Schedule E1-B, line A5, columns Jan.
5 Actual through Dec. Estimated.

6
7 **Q. Has DEF calculated the three-year rolling average gain on non-**
8 **separated power sales in 2025?**

9 A. No. As authorized by FPSC Order No. PSC-2024-0472-AS-EI, DEF's
10 Asset Optimization Mechanism ("AOM") was approved, effective January
11 2025. This approval provides for DEF to implement an AOM for the 2025
12 – 2027 period, and as a result, the sharing mechanism applicable to
13 economy sales that was approved prior to DEF's AOM will not be
14 applicable during the 2025 – 2027 period.

15
16 **CAPACITY COST RECOVERY**

17
18 **Q. What is DEF's 2025 estimated capacity true-up balance and how was**
19 **it developed?**

20 A. DEF's estimated capacity true-up balance is a \$1,221,368 over-recovery.
21 The estimated true-up calculation begins with the actual under-recovered
22 balance of \$2,141,805 as of June 2025. This balance plus the estimated
23 July through December 2025 monthly true-up calculations comprise the
24 estimated \$1,221,368 over-recovered balance at year-end. The projected

1 December 2025 true-up balance includes interest which is estimated from
2 July through December 2025 based on the average of the beginning and
3 ending commercial paper rate applied in June. That rate is 0.361% per
4 month.

5

6 **Q. What are the primary drivers of the estimated year-end 2025 capacity**
7 **under-recovery?**

8 A. The \$1.2 million over-recovery is primarily attributable to a lower Capacity
9 Cost Recovery Clause 2024 net under-recovery of approximately \$3.3M
10 filed on April 2, 2025 in the instant docket, slightly offset by a reduced
11 revenue forecast of approximately \$1.1M and increased capacity costs of
12 approximately \$0.6M.

13

14 **Q. What is DEF's estimated Production Tax Credit (PTC) true-up for the**
15 **2025 period pursuant to Paragraph 23 of DEF's 2024 Settlement**
16 **Agreement approved in Order No. PSC-2024-0472-AS-EI?**

17 A. Paragraph 23 states that DEF may implement a true-up with respect to the
18 level of PTCs associated with investments in solar generation facilities. As
19 shown on Schedule E12-B, line 31, the PTC true-up amounts recorded for
20 the January – June 2025 period are an approximate \$3.6M decrease to
21 costs. These amounts are estimates that were calculated in accordance
22 with the methodology described in Paragraph 23, which states: "DEF will
23 calculate the difference between the dollars actually received from either
24 (a) including the PTCs on a Company tax return or (b) from transferring

1 the PTCs and the calculated amounts using the assumptions on the
2 capacity factor, PTC rate (\$/MWh), and transfer rate shown in Exhibit No.
3 JRP-1 for each solar plant upon commercial operation.” Since these
4 amounts are estimates throughout the year, which will continue to be
5 updated and will be final by year-end, and to promote rate stability for
6 customers, DEF reverses the actuals to date in the month of July 2025
7 such that the 2025 PTC forecast is \$0. The actual results of the PTC true-
8 up will be included in DEF’s 2025 final true-up filing.
9

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

11 **A. Yes.**
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DUKE ENERGY FLORIDA, LLC**DOCKET No. 20250001-EI****Fuel and Capacity Cost Recovery Factors
January 2026 through December 2026****DIRECT TESTIMONY OF
GARY P. DEAN****September 4, 2025**

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

2 A. My name is Gary P. Dean. My business address is 299 1st Avenue North, St. Petersburg,
3 Florida 33701.

4

5 **Q. Have you previously filed testimony before this Commission in Docket No.**
6 **20250001-EI?**

7 A. Yes, I provided direct testimony on April 2, 2025 and July 25, 2025.

8

9 **Q. Has your job description, education, background, and/or professional experience**
10 **changed since that time?**

11 A. No.

12

13 **Q. What is the purpose of your testimony?**

1 A. The purpose of my testimony is to present for Commission approval the fuel and
2 capacity cost recovery factors of Duke Energy Florida, LLC (“DEF” or the “Company”)
3 for the period of January 2026 through December 2026.

4
5 **Q. Do you have an exhibit to your testimony?**

6 A. Yes. I have prepared Exhibit No. (GPD-3), consisting of Parts 1, 2 and 3. Part 1 contains
7 DEF’s fuel cost forecast assumptions. Part 2 contains fuel cost recovery (“FCR”)
8 schedules E1 through E10, H1 and the calculation of the inverted residential fuel rate. I
9 have also included a schedule to support the capital structure components and cost rates
10 relied upon to calculate the return requirements on all capital projects recovered through
11 the fuel clause as required by Order No. PSC-2020-0165-PAA-EU. Part 3 contains
12 capacity cost recovery (“CCR”) schedules.

13
14 **FUEL COST RECOVERY CLAUSE**

15
16 **Q. Please describe the fuel cost factors calculated by the Company for the projection**
17 **period.**

18 A. Schedule E1 shows the calculation of the Company's jurisdictional fuel cost factor of
19 4.414 ¢/kWh. This factor consists of a fuel cost for the projection period of 4.2459
20 ¢/kWh (adjusted for jurisdictional losses), an estimated prior period under-recovery true-
21 up of 0.0030 ¢/kWh, a GPIF cost of 0.0028 ¢/kWh, a Clean Energy Connection (“CEC”)

1 Program bill credit of 0.1626 ¢/kWh, and a Clean Energy Impact (“CEI”) credit of
2 0.0000 ¢/kWh (all zeroes due to rounding). Using this factor, Schedule E1-D shows the
3 calculation and supporting data for the Company’s levelized fuel cost factors for service
4 taken at secondary, primary and transmission metering voltage levels. To perform this
5 calculation, effective jurisdictional sales at the secondary level are calculated and 1%
6 and 2% metering reduction factors are applied to primary and transmission sales,
7 respectively (forecasted at meter level). This is consistent with the methodology used in
8 the development of the CCR factors.

9
10 Schedule E1-D, lines 11-12 show the Company’s proposed tiered rates of 4.127¢/kWh
11 for the first 1,000 kWh and 5.197 ¢/kWh above 1,000 kWh. These rates are developed
12 in the “Calculation of Inverted Residential Fuel Rates” schedule in Part 2 of my exhibit.

13
14 Schedule E1-E develops the Time of Use (“TOU”) multipliers of 1.139 On-Peak, 0.992
15 Off-Peak and 0.917 Discount. The multipliers are then applied to the levelized fuel cost
16 factors for each metering voltage level which results in the final TOU fuel factors to be
17 applied to customer bills during the projection period.

18
19 **Q: What is the amount of the 2025 net true-up balance that DEF has included in the**
20 **fuel cost recovery factor for 2026?**

1 A. DEF has included a projected 2025 net true-up under-recovery balance of \$1,233,365.
2 This amount includes a projected 2025 updated actual/estimated under-recovery of
3 \$76,919,829 and a final 2024 true-up net over-recovery of \$75,686,464 as shown in my
4 Direct Testimony filed on April 2, 2025.
5

6 **Q. Why is there a difference between the estimated 2025 fuel net true-up balance in**
7 **DEF's July 25, 2025, Actual/Estimated Filing and Schedule E1-B of Exhibit No.**
8 **(GPD-3)?**

9 A. The estimated 2025 under-recovery true-up balance of \$47,145,198 on Exhibit No.
10 (GPD-2), Schedule E1-B in the Actual/Estimated Filing includes actual amounts for
11 January through June 2025 and forward curve prices as of June 9, 2025. The estimated
12 under-recovery true-up balance of \$1,233,365 on Exhibit No. (GPD-3), Schedule E1-B
13 has been updated to reflect forward curve natural gas prices as of July 21, 2025.
14

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

17 A. The 2026 projected levelized residential fuel factor of 4.422¢/kWh is an increase of
18 0.497 ¢/kWh or 12.7% from the 2025 levelized residential fuel factor of 3.925 ¢/kWh
19 from DEF's 2025 projection filing approved in Order No. PSC-2024-0481-FOF-EI.
20

1 **Q. Please explain the increase in the 2026 fuel factor compared with the 2025 fuel**
2 **factor.**

3 A. The primary driver of the increase in the 2026 fuel factor is an increase in year-over-
4 year jurisdictional fuel and purchased power expense of approximately \$210M.

5
6 **Q. Have you made any adjustments to your estimated fuel costs for the period January**
7 **through December 2026?**

8 A. Yes. Consistent with Order No. PSC-2018-0240-PAA-EQ, DEF included a retail
9 adjustment of \$10.8M for the January through December 2026 amortization of the
10 Florida Power Development, LLC qualifying facility regulatory asset.

11
12 Per Order No. PSC-2021-0059-S-EI, DEF has included \$66.8M of costs associated with
13 the 2026 projected bill credits for the DEF CEC Program as shown on Exhibit No. (GPD-
14 3), Schedule E1, line 25. As approved by this Order, bill credits are recovered through
15 DEF's fuel and purchased power cost recovery clause.

16
17 Per Order No. PSC-2023-0191-TRF-EI, a cost of \$19.3K is included for the CEI
18 Program as shown on Exhibit No. (GPD-3), Schedule E1, line 26. As approved by this
19 Order, net program revenues from REC sales are credited to the fuel clause to offset
20 other fuel expenses.

1 **Q. Will DEF continue the tiered rate structure for residential customers?**

2 A. Yes, DEF will continue to use inverted rate design for residential fuel factors to
3 encourage energy efficiency and conservation. Specifically, the Company will use a
4 two-tiered fuel charge whereby the charge for a residential customer's monthly usage in
5 excess of 1,000 kWh (second tier) is priced 1.07¢/kWh higher than the charge for the
6 customer's usage up to 1,000 kWh (first tier). The 1,000-kWh price change breakpoint
7 is reasonable because approximately 72% of all residential energy is consumed in the
8 first tier and 28% in the second tier. The Company believes the 1.07 cent higher per unit
9 price, targeted at the second tier of residential class energy consumption, will promote
10 energy efficiency and conservation. This inverted rate design was incorporated into the
11 Company's base rates per the 2021 Settlement Agreement.

12
13 **Q. How was the inverted fuel rate calculated?**

14 A. Exhibit GPD-3, Inverted Fuel Rates, shows the calculation of the fuel cost factors for
15 the two tiers of the residential rate. The two factors are calculated on a revenue neutral
16 basis so that the Company will recover the same fuel costs as it would under a traditional
17 levelized approach. The two-tiered factors are determined by first calculating the amount
18 of revenues that would be generated by the overall levelized residential factor of
19 4.422¢/kWh shown on Schedule E1-D. The two factors are then calculated by allocating
20 the total revenues to the two tiers for residential customers based on the total annual
21 energy usage for each tier.

1 **Q. Has DEF compared its projected gains on short-term wholesale power sales to the**
2 **incentive benchmark?**

3 A. No. As authorized by FPSC Order No. PSC-2024-0472-AS-EI, DEF's Asset
4 Optimization Mechanism ("AOM") was approved, effective January 2025. This
5 approval provides for DEF to implement an AOM for the 2025 – 2027 period, and as a
6 result, the sharing mechanism applicable to economy sales that was approved prior to
7 DEF's AOM is not applicable during the 2025 – 2027 period.

8
9 **Q. Please explain the entry on Schedule E1, line 11, "Fuel Cost of Stratified Sales."**

10 A. DEF has several wholesale contracts with SECI. The contracts provide for the sale of
11 energy and capacity to supply a portion of its load to be dispatched at SECI's discretion.
12 The fuel costs charged to SECI for energy sales are calculated on a "stratified" basis in
13 a manner which recovers the higher cost of intermediate/peaking generation used to
14 provide the energy. DEF is crediting the average fuel cost of the appropriate strata in
15 accordance with Order No. PSC-1997-0262-FOF-EI. The fuel costs of wholesale sales
16 are normally included in the total cost of fuel and net power transactions used to
17 calculate the average system cost per kWh for fuel adjustment purposes. However, since
18 the fuel costs of the stratified sales are not recovered on an average system cost basis,
19 an adjustment has been made to remove these costs and related kWh sales from the fuel
20 adjustment calculation in the same manner that interchange sales are removed from the
21 calculation.

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

3 A. The process begins with a fuel price forecast and a system sales forecast. These forecasts
4 are input into the Company's production cost simulation model along with purchased
5 power information, generating unit operating characteristics, maintenance schedules,
6 incremental delivered fuel prices and other pertinent data. The model then computes
7 system fuel consumption and fuel and purchased power costs. This information is the
8 basis for the calculation of the Company's fuel cost factors and supporting schedules.
9

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

11 A. System sales are forecasted by the DEF Load Forecasting and Fundamentals Department
12 using inputs including a sales-weighted 30-year average of weather conditions at the St.
13 Petersburg, Orlando and Tallahassee weather stations, population projections and State
14 of Florida economic assumptions from Moody's Analytics. The Energy Information
15 Agency surveys of class energy consumption for the South Atlantic Region are
16 incorporated as well.
17

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

19 A. The fuel price forecasts are based on a combination of third-party forecasts and forward
20 contracts currently in place. Additional details and forecast assumptions are provided in
21 Part 1 of my exhibit.

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

3 A. No. Fuel prices can change significantly from day to day. Consistent with past practices,
 4 DEF will continue to monitor fuel prices and update the Projection Filing prior to the
 5 November Hearing if changes in fuel prices warrant such an update.

6
 7 **Q. Is the 2024 GPIF reward discussed in the March 14, 2025, direct testimony of Adam**
 8 **Bingham included in the proposed 2026 rates?**

9 A. Yes. The GPIF reward of \$1,146,970 is included on Schedule E1, line 24.

10
 11 **CAPACITY COST RECOVERY CLAUSE**

12
 13 **Q. Please explain the schedules that are included in Exhibit No. (GPD-3) Part 3.**

14 A. The following schedules are included in my exhibit:

15 Schedule E12-A – Calculation of Projected Capacity Costs – Year 2026

16 Schedule E12-A, page 1, includes estimated 2026 calendar year system capacity
 17 payments to other power suppliers. The retail portion of the capacity payments is
 18 calculated using separation factors consistent with the 2024 Settlement Agreement
 19 approved by the Commission on August 21, 2024, in Docket No. 20240025.

20
 21 The recovery of estimated Dry Casket Storage costs, also referred to as Independent

1 Spent Fuel Storage Installation (“ISFSI”) costs, are included Schedule E12-A, page 1,
2 line 20. The calculation of Total Recoverable Capacity & ISFSI costs are shown on line
3 21.

4
5 Schedule E12-A, page 2, provides the dates and MWs associated with DEF’s Qualifying
6 Facility and purchase power contracts.

7
8 Schedule E12-B – Calculation of Estimated/Actual True-Up - Year 2025

9 Schedule E12-B calculates the estimated true-up capacity over-recovered balance for
10 the calendar year 2025 of \$1,221,368. This schedule was also included in Exhibit No.
11 (GPD-2) to my direct testimony filed on July 25, 2025. The balance on Schedule E12-B
12 is carried forward to Schedule E12-A, page 1, line 18 to be recovered from customers
13 from January through December 2026.

14
15 Schedule E12-D – Calculation of Energy and Demand Percent by Rate Class

16 Schedule E12-D is the calculation of the 12CP and 25% average demand allocators for
17 each rate class. Schedule E12-D also includes the uniform percentage calculation and
18 allocation of the ISFSI revenue requirement to the rate classes.

19
20 Schedule E12-E – Calculation of Capacity Cost Recovery Factors by Rate Class

Schedule E12-E calculates the CCR factors for capacity costs for each rate class based on the 12CP and 25% annual average demand allocators and ISFSI costs from Schedule E12-D. The factors for the Residential, General Service Non-Demand, General Service (GS-2) and Lighting secondary delivery rate classes in cents per kWh are calculated by multiplying total recoverable jurisdictional capacity from Schedule E12-A by the class demand allocation factor and then dividing by estimated effective sales at the secondary metering level. The factor for ISFSI in cents per kWh is calculated by dividing recoverable costs allocated on Schedule E12-D by estimated effective sales at the secondary metering level. The factors for primary and transmission rate classes reflect the application of metering reduction factors of 1% and 2% from the secondary factor, respectively. The factors allocate capacity costs to rate classes in the same way as would be allocated if recovered in base rates. ISFSI costs are allocated to rate classes by applying a uniform percent increase as approved in Order No. PSC-2016-0425-PAA-EI. Pursuant to the 2013 Revised and Restated Stipulation and Settlement Agreement approved in Order No. PSC-13-0598-FOF-EI, DEF has prepared the billing rates for the demand (General Service Demand, Curtailable, and Interruptible) rate classes to be on a kilowatt (kW) rather than a kilowatt-hour (kWh) basis. These changes are reflected on Schedule E12-E in columns 11 through 13.

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

1 A. Yes. The 12CP load factor relationships from DEF's most recent load research
2 conducted for the period January through December 2022 are incorporated into the
3 capacity cost allocation factors. This information is included in DEF's Load Research
4 Report filed with the Commission on April 28, 2023.

5
6 **Q. What is the 2026 projected average retail CCR factor?**

7 A. The 2026 average retail CCR factor is 0.115 ¢/kWh, made up of capacity of 0.088 ¢/kWh
8 and ISFSI costs of 0.027 ¢/kWh.

9
10 **Q. Please explain the change in the CCR factor for the projection period compared to**
11 **the CCR factor currently in effect.**

12 A. The total projected average retail CCR rate of 0.115 ¢/kWh is 0.243 ¢/kWh, or 68%,
13 less than the current 2025 factor of 0.358 ¢/kWh. This decrease is primarily due to a
14 contract terminating at the end of 2025 as reflected on E12-A.

15
16 **Q. Does this conclude your testimony?**

17 A. Yes
18
19
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21

1 (Whereupon, prefiled direct testimony of Adam
2 R. Bingham was inserted.)

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DUKE ENERGY FLORIDA, LLC

DOCKET NO. 20250001-EI

**GPIF Schedules for
January through December 2024**

**DIRECT TESTIMONY OF
ADAM ROSS BINGHAM**

March 14, 2025

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

2 A. My name is Adam Bingham. My business address is 525 South Tryon Street,
3 Charlotte, North Carolina 28202.

4

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

6 A. I am employed by Duke Energy Florida, LLC ("DEF") as a Lead Fuels and
7 Fleet Analyst for Fuels and Systems Optimization.

8

9 **Q. Describe your responsibilities as a Lead Fuels and Fleet Analyst.**

10 A. As a Lead Fuels and Fleet Analyst for Fuels and Systems Optimization, I
11 analyze and model energy portfolios for DEF. My responsibilities include
12 planning and coordination associated with economic system operations,
13 including production cost modeling, outage coordination, dispatch pricing,
14 fuel burn forecasting, position analysis, and commodities analytics.

1 **Q. Please describe your educational background and professional**
2 **experience.**

3 A. I earned Bachelor of Science and Master of Science degrees in Nuclear
4 Engineering from Texas A&M University in 2007 and 2009, respectively.
5 After graduation, I began working for Duke Energy in the Nuclear Fuels
6 Engineering department located in Charlotte, NC, as an Engineer I in the
7 Safety Analysis group. As a Safety Analysis engineer, my responsibilities
8 included performing steady-state and transient computational analysis for a
9 variety of nuclear reactor designs to support fuel reload activities and ensure
10 plant changes comply with design and licensing basis requirements. In 2012,
11 I acquired my Professional Engineer license for the state of North Carolina,
12 which I actively hold today, and in 2013, I was promoted to Senior Engineer.
13 In 2017, I moved to Nuclear Design within the Nuclear Fuels Engineering
14 department as a Senior Engineer, where I performed quantitative analyses
15 to support reload activities that design the fuel loading requirements for each
16 nuclear plant. Additionally, I took on the role of fleet lead for developing and
17 implementing new core monitoring software for all Westinghouse-designed
18 nuclear power plants operated by Duke Energy and its subsidiaries. In 2019,
19 I joined the Fuels and System Optimization department as a Senior Analyst
20 in the Fuels and Fleet Analytics group. Within this role, I performed
21 production cost modeling and system optimization analyses for DEF's
22 portfolio of generating units, power purchases and sales. As part of this
23 transition, I also became the coordinator of DEF's Generating Incentive
24 Factor (GPIF) program. In 2022, I was promoted to the position of Lead
25 Fuels & Fleet Analyst.

1 **Q. What is the purpose of your testimony?**

2 A. The purpose of my testimony is to describe the calculation of DEF's
3 Generating Performance Incentive Factor ("GPIF") reward/(penalty) amount
4 for the period of January through December 2024. This calculation was
5 based on a comparison of the actual performance of DEF's Nine (9) GPIF
6 generating units for this period against the approved targets set for these
7 units prior to the actual performance period.
8

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

10 A. Yes, I am sponsoring Exhibit No. (ARB-1T), which consists of the schedules
11 required by the GPIF Implementation Manual to support the development of
12 the incentive amount. This 28-page exhibit is attached to my prepared
13 testimony and includes as its first page an index to the contents of the
14 exhibit.
15

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

17 A. DEF's calculated GPIF incentive amount is a reward of \$1,146,970. This
18 amount was developed in a manner consistent with the GPIF
19 Implementation Manual. Page 2 of my exhibit shows the system GPIF points
20 and the corresponding reward/(penalty). The summary of weighted incentive
21 points earned by each individual unit can be found on page 4 of my exhibit.
22

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

1 A. The calculation of incentive points was made by comparing the adjusted
2 actual performance data for equivalent availability and heat rate to the target
3 performance indicators for each unit. This comparison is shown on each
4 unit's Generating Performance Incentive Points Table found on pages 9
5 through 17 of my exhibit.

6
7 **Q. Why is it necessary to make adjustments to the actual performance**
8 **data for comparison with the targets?**

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

20
21 In addition, the Bartow CC unit had data excluded during the period in which
22 portions of the unit were intentionally dispatched in simple cycle modes of
23 operation. The Bartow CC unit has the capability for one or more of its
24 combustion turbines to be operated in simple cycle mode while the steam
25 turbine remains on- or offline. Simple cycle operations are intentionally

1 dispatched while the steam turbine is in a planned outage or when it is
2 beneficial for system economics or reliability. When operating in simple cycle
3 mode, the unit's heat rate will deviate significantly from its normal range.
4 DEF's heat rate target setting process for the Bartow CC unit excludes
5 historical data from periods when the unit operated in simple cycle mode.
6 Portions of Bartow CC were dispatched in simple cycle mode several times
7 in 2024 to help effectively manage additional solar generation during periods
8 of lower system load. To be consistent with the target setting process, simple
9 cycle mode heat rate data was excluded from actuals for the purposes of
10 calculating the heat rate for the Bartow CC in year 2024 during those times
11 when the unit was being economically dispatched in simple cycle mode or
12 for system reliability.

13
14 **Q. Have you provided the as-worked planned outage schedules for DEF's**
15 **GPIF units to support your adjustments to actual equivalent**
16 **availability?**

17 A. Yes. Page 27 of my exhibit summarizes the planned outages experienced
18 by DEF's GPIF units during the period. Page 28 presents an as-worked
19 schedule for each individual planned outage.

20
21 **Q. Does this conclude your testimony?**

22 A. Yes.

**IN RE: PETITION ON BEHALF OF DUKE ENERGY FLORIDA
FOR
FUEL AND CAPACITY COST RECOVERY
FINAL TRUE-UP FOR THE PERIOD
JANUARY THROUGH DECEMBER 2024**

FPSC DOCKET NO. 20250001-EI

**GPIF TARGETS AND RANGES FOR
JANUARY THROUGH DECEMBER 2026**

**DIRECT TESTIMONY OF
ADAM ROSS BINGHAM**

September 4, 2025

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

2 A. My name is Adam Bingham. My business address is 525 South Tryon Street, Charlotte,
3 North Carolina 28202.
4

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

6 A. I am employed by Duke Energy Florida, LLC (“DEF”) as a Lead Fuels and Fleet Analyst
7 for Fuels and Systems Optimization.
8

9 **Q. What are your responsibilities in that position?**

10 A. As a Lead Fuels and Fleet Analyst for Fuels and Systems Optimization, I analyze and
11 model energy portfolios for DEF. My responsibilities include planning and coordination
12 associated with economic system operations, including production cost modeling, outage
13 coordination, dispatch pricing, fuel burn forecasting, position analysis, and commodities
14 analytics.
15

1 **Q. Please describe your educational background and professional experience.**

2 A. I earned Bachelor of Science and Master of Science degrees in Nuclear Engineering from
3 Texas A&M University in 2007 and 2009, respectively. After graduation, I began working
4 for Duke Energy in the Nuclear Fuels Engineering department located in Charlotte, NC, as
5 an Engineer I in the Safety Analysis group. As a Safety Analysis engineer, my
6 responsibilities included performing steady-state and transient computational analysis for
7 a variety of nuclear reactor designs to support fuel reload activities and ensure plant
8 changes comply with design and licensing basis requirements. In 2012, I acquired my
9 Professional Engineer license for the state of North Carolina, which I actively hold today,
10 and in 2013, I was promoted to Senior Engineer. In 2017, I moved to Nuclear Design within
11 the Nuclear Fuels Engineering department as a Senior Engineer, where I performed
12 quantitative analyses to support reload activities that design the fuel loading requirements
13 for each nuclear plant. Additionally, I took on the role of fleet lead for developing and
14 implementing new core monitoring software for all Westinghouse-designed nuclear power
15 plants operated by Duke Energy and its subsidiaries. In 2019, I joined the Fuels and System
16 Optimization department as a Senior Analyst in the Fuels and Fleet Analytics group.
17 Within this role, I performed production cost modeling and system optimization analyses
18 for DEF's portfolio of generating units, power purchases and sales. As part of this
19 transition, I also became the coordinator of DEF's Generating Incentive Factor (GPIF)
20 program. In 2022, I was promoted to the position of Lead Fuels & Fleet Analyst.

21
22 **Q. What is the purpose of your testimony?**

1 A. The purpose of my testimony is to provide a recap of actual reward / penalty for the period
2 of January through December 2024 and outline the development of the Company's
3 Generating Performance Incentive Factor ("GPIF") targets and ranges for the period
4 January through December 2026. These GPIF targets and ranges have been developed from
5 individual unit equivalent availability, average net operating heat rate targets, and
6 improvement/degradation ranges for each of the Company's GPIF generating units, in
7 accordance with the Commission's GPIF Implementation Manual.

8
9 **Q. What GPIF incentive amount was calculated and reported in your March 14, 2025**
10 **testimony for the period January through December 2024?**

11 A. DEF's calculated GPIF incentive amount for this period was a reward of \$1,146,970. Please
12 refer to my testimony filed March 14, 2025 for the details of how this incentive amount
13 was calculated.

14
15 **Q. Have there been any adjustments to the incentive amount filed in March?**

16 A. No.

17
18 **Q. Do you have an exhibit to your testimony?**

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

1
2 **Q. Which of the Company's generating units have you included in the GPIF program**
3 **for the upcoming projection period?**

4 A. For the 2026 projection period, the GPIF program includes the following units: Bartow
5 Unit 4, Citrus CC Unit 1, Citrus CC Unit 2, Crystal River Unit 4, Crystal River Unit 5,
6 Hines Units 2, 3 and 4, and Osprey Unit 1. Combined, these units account for 81% of the
7 estimated total system net generation for the period.

8
9 **Q. Have you determined the equivalent availability targets and**
10 **improvement/degradation ranges for the Company's GPIF units?**

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

13
14 **Q. How were the equivalent availability targets developed?**

15 A. The equivalent availability targets were developed using the methodology established for
16 the Company's GPIF units, as set forth in Section 4 of the GPIF Implementation Manual.
17 This includes the formulation of graphs based on each unit's historic performance data for
18 the four individual unplanned outage rates (i.e., forced, partial forced, maintenance, and
19 partial maintenance outage rates), which in combination constitute the unit's equivalent
20 unplanned outage rate ("EUOR"). From operational data and these graphs, the individual
21 target rates are determined through a review of three years of monthly data points. The
22 unit's four target rates are then used to calculate its unplanned outage hours for the
23 projection period. When the unit's projected planned outage hours are taken into account,

1 the hours calculated from these individual unplanned outage rates can then be converted
2 into an overall equivalent unplanned outage factor (“EUOF”). Because factors are additive
3 (unlike rates), the EUOF and planned outage factor (“POF”) when added to the equivalent
4 availability factor (“EAF”) will always equal 100%. For example, an EUOF of 15% and
5 POF of 10% results in an EAF of 75%. The supporting tables and graphs for the target and
6 range rates are contained in pages 49-94 of my exhibit in the section entitled “Unplanned
7 Outage Rate Tables and Graphs.”
8

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

11 A. The methodology described in the GPIF Implementation Manual was used. Ranges were
12 first established for each of the four unplanned outage rates associated with each unit. From
13 an analysis of the unplanned outage graphs, units with small historical variations in outage
14 rates were assigned narrow ranges and units with large variations were assigned wider
15 ranges. These individual ranges, expressed in term of rates, were then converted into a
16 single unit availability range, expressed in terms of a factor, using the same procedure
17 described above for converting the availability targets from rates to factors.
18

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

21 A. No.
22

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

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

5
6 **Q. How were these heat rate targets and ranges developed?**

7 A. The development of the heat rate targets and ranges for the upcoming period utilized
8 historical data from the past three years, as described in the GPIF Implementation Manual.
9 A "least squares" procedure was used to curve-fit the heat rate data to a linear relationship
10 with Net Operating Factor (NOF), and ranges at a 90% confidence level were also
11 established assuming a normal distribution. The analyses and data plots used to develop
12 the heat rate targets and ranges for each of the GPIF units are contained in pages 30-48 of
13 my exhibit in the section entitled "Average Net Operating Heat Rate Curves."

14
15 **Q. How were the GPIF incentive points developed for the unit availability and heat rate**
16 **ranges?**

17 A. GPIF incentive points for availability and heat rate were developed by evenly spreading
18 the positive and negative point values from the target to the maximum and minimum values
19 in the case of availability, and from the neutral band to the maximum and minimum values
20 in the case of heat rate. The fuel savings (loss) dollars were evenly spread over the range
21 in the same manner as described for incentive points. The maximum savings (loss) dollars
22 are the same as those used in the calculation of the weighting factors.
23

1 **Q. How were the GPIF weighting factors determined?**

2 A. To determine the weighting factors for availability, a series of simulations were made using
3 a production costing model in which each unit's maximum equivalent availability was
4 substituted for the target value to obtain a new system fuel cost. The differences in fuel
5 costs between these cases and the target case determine the contribution of each unit's
6 availability to fuel savings. The heat rate contribution of each unit to fuel savings was
7 determined by multiplying the BTU savings between the minimum and target heat rates (at
8 constant generation) by the average cost per BTU for that unit. Weighting factors were then
9 calculated by dividing each individual unit's fuel savings by total system fuel savings.
10

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

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

15 **Q. What is the Company's estimated maximum incentive amount for 2026?**

16 A. The estimated maximum incentive for the Company is \$23,938,468. The calculation of the
17 estimated maximum incentive is shown on page 3 of my Exhibit No. (ARB-1P).
18

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

20 A. Yes.

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

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**IN RE: PETITION ON BEHALF OF DUKE ENERGY FLORIDA, LLC.
FOR**

**FUEL AND CAPACITY COST RECOVERY
FINAL TRUE-UP FOR THE PERIOD
JANUARY THROUGH JULY 2025**

FPSC DOCKET NO. 20250001-EI

**DIRECT TESTIMONY OF
James McClay**

July 25, 2025

I. INTRODUCTION AND QUALIFICATIONS

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

2 **A.** My name is James McClay. My business address is 525 South Tryon Street,
3 Charlotte, North Carolina 28202.

4
5 **Q. By whom are you employed and in what capacity?**

6 **A.** I am employed by Duke Energy Carolinas (“DEC”), an affiliate company of Duke
7 Energy Florida, LLC (“DEF,” “Petitioner” or “Company”) as Managing Director of
8 Natural Gas Trading. In that capacity, I manage the organization responsible for the
9 natural gas trading, optimization, and scheduling functions for the regulated gas-fired
10 generation assets in the Carolinas, Duke Energy Progress, LLC (“DEP” or the
11 “Company”) and Duke Energy Carolinas, LLC (“DEC”), Duke Energy Florida, Duke
12 Energy Indiana and Duke Energy Kentucky (collectively, the “Utilities”), as well as the
13 organization responsible for power trading for Duke Energy Indiana and Duke Energy
14 Kentucky. Additionally, I oversee the execution of the Utilities’ financial hedging
15 programs, fuel oil procurement, and emissions trading.

16

1 **Q. Please describe your education background and professional experience.**

2 **A.** I received a Bachelor Degree in Business Administration majoring in Finance from
3 St. Bonaventure University. I joined Progress Energy in 1998 as the Manager of
4 Power Trading and held that position through early 2003 and then became the
5 Director of Power Trading and Portfolio Management for Progress Energy Ventures
6 through February 2007. From March 2007 through late 2008, I was the Director of
7 Power Trading for Arclight Energy Marketing. From March 2009 through present I
8 have been employed in various managerial roles at Progress Energy and Duke
9 Energy overseeing Power, Natural Gas and Oil trading, hedging procurement. Prior
10 to my tenure with Duke Energy, I was employed for approximately 13 years in
11 Capital Markets as a U.S. Government fixed income securities trader with various
12 banks, and broker/ dealers.

13
14 **Q. What is the purpose of your testimony?**

15 **A.** Duke Energy Florida, LLC (DEF) is submitting its 2026 Risk Management Plan
16 (Plan) for review by the Florida Public Service Commission (FPSC) and discuss the
17 moratorium on hedging.

18
19 **Q. Are you sponsoring any exhibits to your testimony?**

20 **A.** Yes, I am sponsoring the following exhibit:

- 21 • Exhibit No. ____ (JM-1P) – 2026 Risk Management Plan (*Confidential*).

22
23 **Q. Describe the hedging activities that the Company will execute for 2026.**

1 A. As approved by the FPSC on November 12, 2024, DEF is currently under a
2 moratorium on hedging and will not enter into any financial natural gas hedging
3 contracts effective January 1, 2025 throughout the Term of the 2024 Rate Case
4 Settlement, Docket No. 20240025-EI, Order No. PSC-2024-0472-AS-EI.

5
6 **Q. What were the results of DEF's hedging activities for January through July**
7 **2025?**

8 A. As approved by the Commission, DEF is currently under a moratorium on hedging
9 and has not executed any financial hedges for any periods since October 21, 2016,
10 and therefore does not have any hedges in place for 2025.

11
12 **Q. Does this conclude your testimony?**

13 A. Yes.
14

1 (Whereupon, prefiled direct testimony of
2 Michael V. Cashman was inserted.)

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1 **BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

2 **FLORIDA POWER & LIGHT COMPANY**

3 **TESTIMONY OF MICHAEL V. CASHMAN**

4 **DOCKET NO. 20250001-EI**

5 **APRIL 2, 2025**

6

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

8 A. My name is Michael V. Cashman. My business address is 700 Universe Boulevard, Juno
9 Beach, Florida, 33408. I am employed by Florida Power & Light Company (“FPL”) as
10 Executive Director of Wholesale Operations and Trading in the Energy Marketing and
11 Trading Division.

12 **Q. Please summarize your educational background and professional experience.**

13 A. I earned a bachelor’s degree in Mechanical Engineering and a master’s degree in
14 Business Administration from the University of Michigan. I joined the NextEra Energy
15 family of companies in 1998, progressing professionally within the Market Analysis
16 organization from Market Intelligence Analyst to Senior Director before being tapped
17 to lead NextEra Energy Marketing’s Asset Trading and Optimization organization. In
18 2022, responsibilities for Independent System Operator asset operations were
19 consolidated with asset trading and optimization under me acting as the Executive
20 Director of Asset Operations and Trading. In this role my team was responsible for
21 managing the operations and optimization of 36 GW of generation located in eight U.S.
22 and Canadian Regional Transmission Organizations as well as the management of
23 annual commodity price exposure for approximately 250 Bcf of natural gas and 10

1 million barrels of oil and natural gas liquids production. I joined FPL's Energy
2 Marketing and Trading organization in July of 2024 as the Executive Director of
3 Wholesale Operations and Trading where I oversee power trading, coal and fuel oil
4 operations as well as FPL's natural gas scheduling team.

5 **Q. What is the purpose of your testimony?**

6 A. The purpose of my testimony is to present the 2024 results of FPL's activities under
7 the Asset Optimization Program (or "the Program"), an incentive mechanism that was
8 originally approved by Order No. PSC-13-0023-S-EI, dated January 14, 2013, in
9 Docket No. 120015-EI, approved for continuation, with certain modifications, by Order
10 No. PSC-16-0560-AS-EI, dated December 15, 2016, in Docket No. 160021-EI, and
11 approved as an ongoing program, with further modifications, by Order No. PSC-2021-
12 0446-S-EI, dated December 2, 2021, in Docket No. 20210015-EI.

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

15 A. Yes, I am sponsoring the following exhibit:

- 16 • Exhibit MVC-1, consisting of 4 pages:
- 17 ▪ Page 1 – Total Gains Schedule
 - 18 ▪ Page 2 – Wholesale Power Detail
 - 19 ▪ Page 3 – Asset Optimization Detail
 - 20 ▪ Page 4 – Incremental Optimization Costs

21 **Q. Please provide an overview of the Asset Optimization Program.**

22 A. The Asset Optimization Program is designed to create additional value for FPL's
23 customers while also providing an incentive to FPL if certain customer-value

1 thresholds are achieved. The Program includes gains from wholesale power sales and
2 savings from wholesale power purchases, as well as gains from other forms of asset
3 optimization. Under the original 2012 approval, other forms of asset optimization
4 include, but are not limited to, natural gas storage optimization, natural gas sales,
5 capacity releases of natural gas transportation, capacity releases of electric transmission
6 and potentially capturing additional value from a third party in the form of an Asset
7 Management Agreement.

8 **Q. Please describe the modifications that were made to the Asset Optimization**
9 **Program in FPL's 2021 rate case and approved by Order No. PSC-2021-0446-AS-**
10 **EI.**

11 A. Five modifications were made to the Program through Order No. PSC-2021-0446-AS-
12 EI. The following modifications are described in Paragraph 21 of the Stipulation and
13 Settlement Agreement:

14 (i) FPL may optimize all fuel sources – beyond just natural gas supply and capacity
15 – when it is reasonable and in the best interests of customers to do so based on the
16 system requirements, market demand, and market price of the fuel or capacity at the
17 time;

18 (ii) FPL may monetize its renewable energy credits (“RECs”);

19 (iii) The number of annual savings thresholds is reduced from four to three for
20 reporting purposes. Threshold 1: FPL customers receive 100% of the asset
21 optimization gains up to a threshold of \$42.5 million. Threshold 2: FPL will retain
22 60% and customers will receive 40% of incremental gains between \$42.5 million and

1 \$100 million. Threshold 3: FPL will retain 50% and customers will receive 50% of
2 incremental gains in excess of \$100 million.

3 (iv) The per-MWh variable power plant O&M rate shall be \$0.48/MWh; and

4 (v) Optimization activities, variable power plant O&M rates, and savings
5 thresholds shall be considered “adjustable parameters” such that FPL may request that
6 the Commission review and adjust these parameters every four years in the Fuel Cost
7 Recovery Docket.

8 **Q. Please summarize the activities and results of the Asset Optimization Program for**
9 **2024.**

10 A. FPL’s activities under the Asset Optimization Program in 2024 delivered \$125,038,686
11 in total gains. During 2024, FPL’s optimization activities consisted of wholesale power
12 purchases and sales, natural gas sales in the market and production areas, gas storage
13 utilization, the capacity release of firm natural gas transportation, and the sale of RECs.
14 Additionally, FPL entered into several Asset Management Agreements related to a
15 portion of upstream gas transportation during 2024. The total gains of \$125,038,686
16 exceed the sharing thresholds of \$42.5 million and \$100 million. Therefore, the
17 incremental gains above \$42.5 million and up to \$100 million will be shared between
18 customers and FPL 40% and 60%, respectively, with all gains above \$100 million
19 shared equally. Exhibit MVC-1, Page 1, shows monthly gain totals, threshold levels,
20 and the final gains allocation for 2024.

1 **Q. Please provide the details of FPL's wholesale power activities under the Asset**
2 **Optimization Program for 2024.**

3 A. The details of FPL's 2024 wholesale power sales and purchases are shown separately
4 on Page 2 of Exhibit MVC-1. FPL had gains of \$50,386,789 on wholesale sales and
5 savings of \$6,381,014 on wholesale purchases for the year.

6 **Q. Please provide the details of FPL's other asset optimization activities under the**
7 **Program for 2024.**

8 A. The details of FPL's 2024 asset optimization activities unrelated to wholesale power
9 are shown on Page 3 of Exhibit MVC-1. FPL had a total of \$68,270,883 of gains that
10 were the result of nine different forms of asset optimization.

11 **Q. Did FPL incur incremental O&M expenses related to the operation of the Asset**
12 **Optimization Program in 2024?**

13 A. Yes. FPL incurred personnel expenses of \$864,547 related to the costs associated with
14 four and one-half personnel required to support FPL's activities under the Program.

15
16 On the variable power plant O&M side, FPL's actual net economy power sales less
17 purchases totaled 2,493,253 MWh (2,610,661 MWh of economy sales and 117,408
18 MWh of economy purchases), resulting in net variable power plant O&M costs of
19 \$1,196,761 for 2024.

20 **Q. Overall, were FPL's activities under the Asset Optimization Program successful**
21 **in 2024?**

22 A. Yes. FPL's activities under the Program were highly successful in 2024. On the
23 wholesale power side, suitable market conditions helped drive strong wholesale power

1 sales consistently throughout the year, with the winter season delivering the highest
2 benefits. FPL was also able to opportunistically purchase power from the market to
3 avoid running more expensive generation, predominantly during maintenance season
4 and during the height of the summer. Overall, FPL was able to consistently capitalize
5 on power market opportunities throughout the year to deliver \$56.8 million in customer
6 benefits. Market opportunities for asset optimization activities related to natural gas
7 were also fairly consistent throughout the year, and coupled with the sale of RECs,
8 delivered \$68.3 million in benefits. In total, all optimization activities delivered
9 significant benefits of \$125,038,686, which contrast very favorably to the total
10 optimization expenses (personnel and variable power plant O&M) of \$2,061,309.

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

12 A. Yes.

1 **BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

2 **FLORIDA POWER & LIGHT COMPANY**

3 **TESTIMONY OF MICHAEL V. CASHMAN**

4 **DOCKET NO. 20250001-EI**

5 **SEPTEMBER 4, 2025**

6
7 **Q. Please state your name, business address, employer and position.**

8 A. My name is Michael V. Cashman. My business address is 700 Universe Boulevard,
9 Juno Beach, Florida, 33408. I am employed by Florida Power & Light Company
10 ("FPL") as Executive Director of Wholesale Operations in the Energy Marketing and
11 Trading Division.

12 **Q. Have you previously testified in this docket?**

13 A. Yes.

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

16 A. Yes, I am sponsoring Exhibit MVC-2 - 2026 Projected Dispatch Costs and Availability. I
17 am co-sponsoring the following schedules included in the exhibits of FPL witness
18 Mohomed:

- 19 • Schedules E2 through E9 and H1 included in Exhibit AM-5; and
20 • Schedule E12 included in Exhibits AM-6

1 **Q. What is the purpose of your testimony?**

2 A. The purpose of my testimony is to present and explain FPL's projections for (1) the
3 dispatch costs of natural gas, light fuel oil, and coal; (2) the availability of natural gas
4 to FPL; (3) generating unit heat rates and availabilities; (4) the quantities and costs of
5 wholesale (off-system) power sales and purchased power transactions; and (5) the
6 Incremental Optimization Costs included in FPL's 2026 Projection Filing.

7

8

FUEL PRICE FORECAST

9 **Q. What forecast methodologies has FPL used for the 2026 recovery period?**

10 A. For natural gas commodity prices, the forecast methodology relies upon the NYMEX
11 Natural Gas Futures contract prices (forward curve). For light fuel oil prices, FPL utilizes
12 Over-The-Counter ("OTC") forward market prices. For coal, FPL utilizes actual coal
13 purchases, current market quotes, and information from S&P Global to develop its short-
14 and long-term coal price forecasts. Forecasts for the availability of natural gas are
15 developed internally at FPL and are based on contractual commitments and market
16 experience. The forward curves for both natural gas and light fuel oil represent expected
17 future prices at a given point in time. The basic assumption made with respect to using
18 the forward curves is that all available data that could impact the price of natural gas and
19 light fuel oil in the short-term is incorporated into the curves at all times. FPL utilized
20 forward curve prices from the close of business on August 1, 2025 for calculating its
21 projected fuel costs included in the 2026 Fuel Cost Recovery ("FCR") factors. This
22 forecast methodology and the resulting fuel forecast were utilized to develop cost
23 projections for FPL during the January 2026 through December 2026 time period.

1 **Q. Has FPL previously used these same forecasting methodologies?**

2 A. Yes. For natural gas and light fuel oil, FPL began using the NYMEX Natural Gas Futures
3 contract prices (forward curve) and OTC forward market prices, respectively, in 2004 for
4 its 2005 projections and has used this methodology consistently since that time. For coal
5 price forecasting, FPL implemented the methodology described above beginning in
6 March 2022.

7 **Q. What are the factors that typically can affect FPL's natural gas prices during the**
8 **January through December 2026 period?**

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

14

15 Henry Hub natural gas spot prices averaged \$3.72 per MMBtu for the first half of 2025,
16 compared with an annual average of \$2.25 per MMBtu in 2024. In its August 2025 Short-
17 Term Energy Outlook ("STEO"), the Energy Information Administration ("EIA")
18 forecasts that Henry Hub natural gas spot prices will average \$3.60 per MMBtu for 2025
19 and \$4.30 per MMBtu in 2026.

20

21 In its latest STEO, the EIA forecasts that demand for natural gas will have a slight
22 reduction in 2026, dropping from roughly 91.4 billion cubic feet per day ("BCF/day") in
23 2025 to 91.2 BCF/day in 2026 due to normalizing weather.

1 The EIA forecasts dry natural gas production to average 106.4 BCF/day during 2025 and
2 slightly decrease to 106.1 BCF/day in 2026.

3 **Q. Please describe FPL's natural gas transportation portfolio for the January through**
4 **December 2026 period.**

5 A. FPL utilizes the Florida Gas Transmission Company, LLC ("FGT"), Gulfstream Natural
6 Gas System, LLC ("Gulfstream"), Sabal Trail Transmission, LLC ("Sabal Trail"), Florida
7 Southeast Connection, LLC ("FSC"), and Gulf South Pipeline Company, LLC ("Gulf
8 South") pipelines to deliver natural gas to its generation facilities. FPL's total firm
9 transportation capacity on FGT ranges from 1,387,000 to 1,511,000 MMBtu/day. It also
10 has 695,000 MMBtu/day of firm transport on Gulfstream, 600,000 MMBtu/day of firm
11 transport on Sabal Trail/FSC, and 30,000 MMBtu/day of firm transport on Gulf South.

12
13 FPL also has firm transportation capacity on several upstream pipelines that provide FPL
14 access to onshore gas supply. FPL has 325,000 MMBtu/day of firm transport on the
15 Southeast Supply Header, LLC ("SESH") pipeline, 121,500 MMBtu/day of firm transport
16 with an additional 21,477 MMBtu/day of firm transport (January-March 2026) on the
17 Transcontinental Gas Pipe Line Company, LLC ("Transco") Zone 4A lateral, 200,000
18 MMBtu/day (January through March and November through December) and 345,000
19 MMBtu/day (April through October) of firm transport on the Gulf South pipeline, 80,000
20 MMBtu/day of firm transport on the Gulf South and Destin Pipeline Company, LLC
21 ("Destin") pipelines combined, 75,000 MMBtu/day (January – October) of firm transport
22 on the Midcontinent Express Pipeline LLC ("MEP") and Destin pipelines combined, and
23 225,000 MMBtu/day of firm transport on the FGT and Trunkline Gas Company, LLC

1 (“Trunkline”) pipelines combined. FPL’s firm transportation rights on these pipelines
2 provide access for up to 1,171,500 MMBtu/day of onshore natural gas supply during the
3 summer season, which helps diversify FPL’s natural gas portfolio and enhance the
4 reliability of fuel supply.

5 **Q. Please describe FPL’s natural gas storage position.**

6 A. FPL currently holds firm natural gas storage capacity of 4.0 BCF at Bay Gas Storage
7 (“Bay Gas”) in southwest Alabama, with capacity expanding to 5.0 BCF effective April
8 1, 2026, 1.0 BCF of firm natural gas storage capacity in Southern Pines Energy Center
9 (“Southern Pines”), located in southeast Mississippi, with capacity expanding to 3.0 BCF
10 effective April 1, 2026, and 2.0 BCF of firm natural gas storage capacity in Petal Gas
11 Storage, located in southern Mississippi.

12

13 FPL continually evaluates its natural gas storage portfolio and will make adjustments as
14 required to maintain reliability, provide the necessary flexibility to respond to demand
15 changes, and to diversify its overall portfolio.

16 **Q. What are FPL’s projections for the dispatch cost and availability of natural gas**
17 **for the January through December 2026 period?**

18 A. FPL’s projections of the system average dispatch cost and availability of natural gas,
19 by transport type, by pipeline and by month, are provided on page 1 of Exhibit MVC-2.

20 **Q. Please describe FPL’s utilization of light fuel oil.**

21 A. FPL primarily utilizes light fuel oil (or ultra-low sulfur diesel) as a back-up fuel in its
22 natural gas-fired generation units. FPL’s light fuel oil system is comprised of
23 approximately 1.5 million barrels of storage that provides an average of 82 hours of full

load operation across the fleet of dual-fired units. FPL's light fuel oil system offers substantial flexibility through varying tank sizes, resupply options, and through varying locations and proximity to supply sources.

Q. Please provide FPL's projection for the dispatch cost of light fuel oil for the January through December 2026 period.

A. FPL's projection for the system average dispatch cost of light fuel oil, by month, is provided on page 1 of Exhibit MVC-2.

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

A. FPL's projected dispatch cost is based on FPL's price projection for coal delivered to the plant.

Q. Please provide FPL's projection for the dispatch cost of coal at Plant Scherer for the January through December 2026 period.

A. FPL's projection for the system average dispatch cost of coal for this period, by month, is shown on page 1 of Exhibit MVC-2.

Q. Do the fuel costs reflected on Schedule E3 for light oil and coal differ from the dispatch costs shown on page 1 of Exhibit MVC-2?

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

PLANT HEAT RATES, OUTAGE FACTORS, PLANNED

OUTAGES, AND CHANGES IN GENERATING CAPACITY

Q. Please describe how FPL developed the projected Average Net Heat Rates shown on Schedule E4 of Exhibit AM-5.

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

Q. Are you providing the outage factors projected for the period January through December 2026?

A. Yes. This data is shown on page 2 of Exhibit MVC-2.

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

A. The unplanned outage factors were developed using the actual historical full and partial outage event data for each of the units. The historical unplanned outage factor of each generating unit was adjusted, as necessary, to eliminate non-recurring events and recognize the effect of planned outages to arrive at the projected factor for the period January through December 2026.

Q. Please describe the significant planned outages for the January through December 2026 period.

A. Planned outages at FPL's nuclear units are the most significant in relation to fuel cost recovery. St. Lucie Unit 2 is scheduled to be out of service from April 18, 2026 until May

30, 2026, or 42 days during the period. Turkey Point Unit 3 is scheduled to be out of service from January 31, 2026 until April 16, 2026, or 75 days during the period.

Q. Please identify any changes to FPL's generation capacity projected to take place during the January through December 2026 period.

A. As shown in FPL's 2025 Ten Year Power Plant Site Plan (Schedule 8, page 163), FPL projects a net increase in its 2026 summer firm capacity of 1,435 MW. This increase is attributable to the addition of 114 MW of solar generation and 1,346 MW of battery storage. The additions are off-set by solar degradation (12 MW) and the retirement of gas-fired generation (12 MW).

WHOLESALE (OFF-SYSTEM) POWER AND

PURCHASED POWER TRANSACTIONS

Q. Are you providing the projected wholesale (off-system) power sales and purchased power transactions forecasted for January through December 2026?

A. Yes. This data is shown on Schedules E6, E7, E8, and E9 of Exhibit AM-5 of this filing.

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

A. FPL purchases FERC-mandated wholesale energy from Qualifying Facilities. Additionally, FPL engages in structured Power Purchase Agreements ("PPA") and shorter term, opportunistic economy power sales and purchases, benefiting FPL's customers. Power purchases and sales are executed under specific tariffs that allow FPL to transact with a given entity. Although FPL primarily transacts on a short-term basis (hourly and daily transactions), FPL continuously searches for all opportunities to lower

1 fuel costs through purchasing and selling wholesale power, regardless of the duration of
2 the transaction.

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

5 A. Wholesale (off-system) economy power purchases and sales are projected based upon
6 estimated generation costs, generation availability, fuel availability, expected market
7 conditions and historical data.

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

10 A. FPL has projected 2,859,837 MWh of wholesale (off-system) economy power sales for
11 the period of January through December 2026. The projected fuel cost related to these
12 sales is \$93,820,551. The projected transaction revenue from these sales is \$130,431,318.
13 After considering the transmission costs and capacity revenues, the projected gain is
14 \$30,340,852.

15 **Q. In what schedule are the fuel costs for wholesale (off-system) economy power sales**
16 **transactions reported?**

17 A. Schedule E6 of Exhibit AM-5 provides the total MWh of energy, total dollars for fuel
18 adjustment, total cost and total gain for wholesale (off-system) economy power sales.

19 **Q. What are the forecasted amounts and costs of wholesale (off-system) economy power**
20 **purchases for the January to December 2026 period?**

21 A. The costs of these economy purchases are shown on Schedule E9 of Exhibit AM-5.
22 For the period, FPL projects it will purchase a total of 137,820 MWh at a cost of
23 \$7,925,470. If FPL generated this energy, FPL estimates that it would cost

1 \$10,202,830. Therefore, these economy purchases are projected to result in savings of
2 \$2,277,360.

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

5 A. Yes. FPL purchases energy under two contracts with the Solid Waste Authority of
6 Palm Beach County (“SWA”) and under two wind energy purchase agreements
7 (“Kingfisher I” and “Kingfisher II”) with Morgan Stanley Capital Group. FPL has
8 extended a PPA with Southern Company for output from Santa Rosa Energy Center
9 Combined Cycle Plant (“Santa Rosa PPA”) for 230 MW of capacity and energy, in
10 order to supplement FPL’s winter reserves, while providing fuel savings. The Santa
11 Rosa PPA extension runs from January 1, 2026 through February 28, 2026. In addition,
12 FPL contracts to purchase and sell nuclear energy under the St. Lucie Plant Nuclear
13 Reliability Exchange Agreements with Orlando Utilities Commission and Florida
14 Municipal Power Agency. Lastly, FPL purchases energy and capacity from Qualifying
15 Facilities and “as-available” energy from a number of cogeneration and small power
16 production facilities under existing tariffs and contracts, including solar energy
17 purchases under agreements with three solar facilities located in Northwest Florida.

18 **Q. Please provide the projected energy costs to be recovered through the FCR Clause**
19 **for the power purchases referred to above during the January through December**
20 **2026 period.**

21 A. Energy purchases under the SWA agreements are projected to be 807,962 MWh for the
22 period at an energy cost of \$36,866,954. FPL projects to purchase 1,031,280 MWh at
23 an energy cost of \$57,017,979 from Kingfisher I and Kingfisher II combined.

1 Additionally, FPL projects to purchase 193,103 MWh at an energy cost of \$7,910,200
2 under the Santa Rosa PPA. FPL's cost for energy purchases under the St. Lucie Plant
3 Reliability Exchange Agreements is a function of the operation of St. Lucie Unit 2 and
4 the fuel costs to the owners. For the period, FPL projects purchases of 545,442 MWh
5 at an energy cost of \$2,642,475. These projections are shown on Schedule E7 of
6 Exhibit AM-5.

7
8 In addition, as shown on Schedule E8 of Exhibit AM-5, FPL projects that purchases
9 from Qualifying Facilities for the period will provide 568,031 MWh at a cost of
10 \$29,363,628.

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

13 A. For those contracts that entitle FPL to purchase "as-available" energy at FPL's avoided
14 energy cost, FPL used its fuel price forecasts as inputs to the GenTrader model to
15 project the avoided energy cost that is used to set the price of these energy purchases
16 each month. For those contracts that are not based on FPL's avoided energy cost (firm
17 capacity and energy and "as-available" energy), the applicable Unit Energy Cost
18 mechanisms prescribed in the contracts are used to project monthly energy costs.

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

21 A. FPL projects to sell 629,806 MWh of energy at a cost of \$3,588,921. These projections
22 are shown on Schedule E6 of Exhibit AM-5.

23

HEDGING/ RISK MANAGEMENT PLAN

Q. Has FPL filed a Hedging Activity Final True-Up Report for 2024, consistent with the Hedging Order Clarification Guidelines, as required by Order No. PSC-08-0667-PAA-EI issued on October 8, 2008?

A. No. Pursuant to Paragraph 27 of the 2021 Rate Settlement, FPL's fuel hedging program was under a moratorium. Therefore, FPL had no hedging activity to report for 2024.

Q. Has FPL filed a comprehensive Risk Management Plan for 2026, consistent with the Hedging Order Clarification Guidelines as required by Order No. PSC-08-0667-PAA-EI issued on October 8, 2008?

A. Yes. On September 2, 2025, FPL filed a revised comprehensive Risk Management Plan for 2026.

THE ASSET OPTIMIZATION PROGRAM

Q. Has FPL included a projection of the customer benefits it expects to achieve under the Asset Optimization Program in 2026?

A. Yes. FPL has included projections for savings on wholesale power purchases (Schedule E9), projections for gains on wholesale power sales (Schedule E6), and projections for other types of asset optimization measures (Schedule E2) for 2026.

Q. Has FPL included in its 2026 FCR factors projections of the Incremental Optimization Costs that it will incur under the Asset Optimization Program?

A. Yes. FPL has included in its 2026 FCR factors, Incremental Optimization Costs from two categories: (i) incremental personnel, software and hardware costs associated with

1 managing the various asset optimization activities, and (ii) variable power plant O&M
2 (“VOM”) costs associated with wholesale economy sales and purchases.

3 **Q. Have you made any changes in incremental personnel dedicated to the Asset**
4 **Optimization Program?**

5 A. FPL intends to dedicate an additional three and a half personnel to the Program to optimize
6 natural gas.

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

9 A. FPL projects to incur incremental expenses of \$2,354,000 in 2026 for the salaries and
10 expenses related to the eight employees that will support the Asset Optimization Program.

11 **Q. Please describe the costs that are included in FPL’s projections for VOM**
12 **expenses.**

13 A. FPL has included for recovery in its 2026 FCR factors VOM expenses that reflect the
14 netting of economy sales and purchases. As shown on Schedules E6 and E9 of Exhibit
15 AM-5, FPL projects to sell 2,859,837 MWh and purchase 137,820 MWh of economy
16 power. The 2021 Rate Settlement prescribes a VOM rate of \$0.48/MWh. Applying
17 that rate, FPL projects to incur VOM expenses of \$1,372,722 associated with its
18 economy sales and to avoid \$66,154 with its economy purchases. FPL has included for
19 recovery the net of these two figures, \$1,306,568 (Schedule E2, sum of line nos. 14 and
20 15), in its 2026 FCR factors.

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

22 A. Yes.



David M. Lee
Senior Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
(561) 691-7263
(561) 691-7135 (facsimile)
David.Lee@fpl.com

September 11, 2025

-VIA ELECTRONIC FILING-

Adam Teitzman
Division of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket No. 20250001-EI

Dear Mr. Teitzman:

Florida Power & Light Company attaches for electronic filing an errata sheet for the prepared testimony of witness Michael V. Cashman as well as Exhibit MVC-2 to his testimony, which was originally filed on September 4, 2025.

Please feel free to contact me with any questions regarding this filing.

Sincerely,

s/ David M. Lee
David M. Lee

Attachments

cc: Counsel for Parties of Record (w/ attachments)

Florida Power & Light Company

700 Universe Boulevard, Juno Beach, FL 33408

23144190v1

CERTIFICATE OF SERVICE
Docket No. 20250001-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished
 by electronic service on this 11th day of September 2025 to the following:

Ryan Sandy
Office of General Counsel
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ERRATA SHEET

WITNESS: MICHAEL V. CASHMAN
DIRECT TESTIMONY DATED SEPTEMBER 4, 2025

Page	Line	Change
4	9	Change “1,387,000 to 1,511,000” to “1,487,000 to 1,611,000”
	15	Add “169,406 MMBtu/day of firm transport (January through March), 147,929 MMBtu/day (April through June) and” after “pipeline,”
	16	Change “with an additional 21,477 MMBtu/day of firm transport (January-March 2026)” to “for the remainder of 2026”
	17	Change “Zone 4A lateral” to “pipeline”

Exhibit No.	Page No.	Change
MVC-2	1 of 2	Replace originally filed Exhibit MVC-2 page 1 with attached Exhibit MVC-2 page 1 Errata

1 (Whereupon, prefiled direct testimony of
2 Daniel DeBoer was inserted.)

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF DANIEL DEBOER

DOCKET NO. 20250001-EI

SEPTEMBER 4, 2025

Q. Please state your name and address.

A. My name is Daniel DeBoer. My work business address is 15430 Endeavor Drive, Jupiter, Florida 33478.

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

A. I am employed by Florida Power & Light Company (“FPL or the Company”) as Vice President Nuclear Long-Range Strategy & Execution.

Q. Have you previously filed testimony in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. My testimony presents and explains FPL’s projections of nuclear fuel costs for the thermal energy to be produced by our nuclear units measured in Million British Thermal Units or (“MMBtu”) for 2026. Nuclear fuel costs were input values to the GenTrader model that is used to calculate the costs included in the proposed fuel cost recovery factors for the period January 2026 through December 2026. I am also supporting FPL’s projected 2026 incremental plant security and Fukushima-related costs. Additionally, my testimony discusses unplanned outages that occurred at the nuclear power plants and over the period from August 2024 through July 2025.

1 **Q. Aside from planned maintenance outages, does FPL project that its nuclear units**
2 **will achieve 100% availability?**

3 A. No, it does not. No nuclear plant in the industry projects 100% availability. Nuclear
4 plants are complex industrial facilities that consist of dozens of interdependent systems,
5 hundreds of major components, tens of thousands of sub-components, tens of thousands
6 of tubes, miles of piping and many redundant safety features. FPL continuously improves
7 the physical plant, procedures, and processes to improve reliability and maintain nuclear
8 safety. However, even when prudent actions are taken, FPL's nuclear units – like all
9 nuclear units in the industry – experience equipment failures and unplanned outages. My
10 testimony describes outages that warrant further explanation for the Florida Public Service
11 Commission.

12

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Nuclear Fuel Costs

14 **Q. What is the basis for FPL's projections of nuclear fuel costs?**

15 A. FPL's nuclear fuel cost projections are developed using projected energy production at its
16 nuclear units and current operating schedules for the period January 2026 through
17 December 2026.

18 **Q. Please provide FPL's projection for nuclear fuel unit costs and energy for the period**
19 **January 2026 through December 2026.**

20 A. FPL projects the nuclear units will burn 293,925,680 MMBtu of energy at a cost of
21 \$0.5541 per MMBtu for the period January 2026 through December 2026. Projections
22 by nuclear unit and by month are listed in Schedule E-3 of Exhibit AM-5, which is
23 attached to FPL witness Mohamed's testimony.

Nuclear Plant Incremental Security Costs

1
2 **Q. What is FPL's projection of incremental security costs at its nuclear power plants**
3 **for the period January 2026 through December 2026?**

4 A. FPL projects that it will incur \$32.4 million in incremental nuclear power plant security
5 costs in 2026. The costs consist of \$2.0 million of capital expenditures and \$30.4 million
6 of O&M expenses.

7 **Q. Please provide a brief description of the items included in incremental nuclear power**
8 **plant security costs.**

9 A. The projection includes the additional costs incurred in maintaining a security force as a
10 result of implementing the NRC's fitness-for-duty rule under 10 CFR Part 26, which
11 strictly limits the number of hours that nuclear security personnel may work; additional
12 personnel training; maintenance of the physical upgrades resulting from implementing the
13 NRC's physical security rule under 10 CFR Part 73; and impacts of implementing the
14 NRC's cyber security rule under 10 CFR Part 73. It also includes force-on-force
15 modifications at the St. Lucie and Turkey Point nuclear sites to effectively mitigate new
16 adversary tactics and capabilities employed by the NRC's Composite Adversary Force,
17 as required by NRC inspection procedures.

Fukushima-Related Costs

Q. What is FPL's projection of Fukushima-related costs at its nuclear power plants for the period January 2026 through December 2026?

A. FPL's current projection of Fukushima-related costs for 2026 is approximately \$945 thousand in O&M expenses.

Q. Please provide a brief description of the items included in this projection of Fukushima-related costs.

A. The projection includes FPL's share of costs incurred for equipment, storage, and transportation, to support the shared Regional Response Centers (a warehouse of off-site portable equipment shared by the industry).

Unplanned Outage or Downpower Events

Q. Please describe the unplanned outages or downpowers at FPL's nuclear plants from August 2024 through July 2025 for which FPL wishes to provide further information.

A. On October 12, 2024, Turkey Point Unit 3 was manually removed from service due to a condenser tube leak. On December 4, 2024, Turkey Point Unit 3 automatically tripped due to a reactor protection equipment instrumentation failure. Lastly, on June 21, 2025, Turkey Point Unit 4 automatically tripped due to a bus-lockout of a vital 4kV bus in response to an overcurrent condition sensed from the associated Emergency Diesel Generator. FPL's responses to the unplanned outage events were prudent and efficient, and the units were returned to service safely. More details are described below.

October 12, 2024, Turkey Point Unit 3

Q. Please describe the circumstances related to the October 12 event.

A. On October 12, 2024, Turkey Point Unit 3 experienced elevated steam generator sodium and chloride concentration due to a through-wall leak of a 3AS main condenser tube. This leak was of sufficient magnitude that it initially required a controlled power reduction and then a subsequent unit shutdown per procedural requirements.

Q. What did the investigation of the condenser tube leak find?

A. An unidentified defect in the affected tube was introduced during fabrication of the 3AS condenser water box assembly installed in 2013. Previous preventive maintenance activities, i.e., eddy current testing, determined this tube did not meet any established plugging criteria and therefore the tube was not plugged.

Q. What actions were taken to address this finding?

A. The affected condenser tube was removed and plugged. The tube was sent for forensic analysis which determined the failure occurred during fabrication. The unit was safely returned to service within approximately seven days.

Q. What actions does FPL plan to take to prevent recurrence?

A. The inspection and repair, as needed, of the Unit 3 (and Unit 4 – Extent of Condition) condenser tube bundles will occur at the next refueling outage. Additionally, the Turkey Point condensers Eddy Current Testing (ECT) technical requirements sheets were revised to include complex ECT signal measurements as potential tube plugging criteria to ensure reliability for the future.

December 4, 2024, Turkey Point Unit 3

2 **Q. Please describe the circumstances related to the December 4 event.**

3 A. On December 4, 2024, Turkey Point Unit 3 automatically tripped offline due to an
4 unanticipated Reactor Protection System channel failure coincident with a redundant
5 Reactor Protection System channel that was also out of service for planned surveillance
6 testing.

7 **Q. What did the investigation of the Reactor Protection Channel Failure find?**

8 A. The Reactor Protection System Channel 2 loop calculation processor and associated data
9 link handler printed circuit board cards randomly failed while within their expected useful
10 life.

11 **Q. What actions were taken to address this failure of the Reactor Protection System?**

12 A. The failed cards in the Reactor Protection System channel loop processor subsystem
13 were replaced with new circuit cards. Other similar circuit cards were evaluated and
14 determined to have a prudent maintenance strategy. The unit was safely returned to
15 service within approximately three days.

16 **Q. What actions does FPL plan to take to prevent recurrence?**

17 A. While the risk of a recurrence of this condition cannot be completely eliminated, the
18 amount of time the unit is in a single point vulnerability condition to a unit trip during
19 testing was evaluated to minimize the time the unit is in this condition. The applicable
20 procedures were revised to implement these improvements. This would not have
21 necessarily prevented the trip but will minimize the time the unit is vulnerable to the
22 trip condition.

June 21, 2025, Turkey Point Unit 4

2 **Q. Please describe the circumstances related to the June 21 event.**

3 A. During the performance of the 4A Emergency Diesel Generator (EDG) post maintenance
4 testing, Turkey Point Unit 4 reactor automatically tripped because of a 4A 4kv bus lock-
5 out. The bus lock-out was caused by the bus protective relay scheme in response to an
6 overcurrent condition sensed from the EDG.

7 **Q. What did the investigation of the trip find?**

8 A. An existing testing procedure provided general guidance for placing and removing a relay
9 positioning hold during testing of alarms. This is considered “skill of the craft” and
10 repeated on multiple relays. The investigation determined the blocking mechanism
11 remained in place on one of the voltage balance relays, keeping the relay in an actuated
12 state. This issue alone would not have caused the bus lock-out and subsequent reactor
13 trip. The presence of a blown fuse was discovered in the 4A 4kV bus voltage reference
14 circuit, resulting in a missing phase of reference voltage. Both conditions were necessary
15 to facilitate the bus lock-out. There were no discernable ties to identify that a blown fuse
16 existed in the circuit.

17 **Q. What actions were taken to address this issue?**

18 A. The blocking device was removed to restore the electrical circuit. Necessary testing to
19 restore operability of the bus and the diesel generator was performed prior to unit restart.
20 Additionally, the failed fuse was replaced to restore the sensing circuit. The unit was
21 safely restored to service in approximately five days.

1 **Q. What actions will FPL take to prevent reoccurrence?**

2 A. A non-conductive, high-visibility tool (wedge) for EDG Voltage Balance Relay testing is
3 being fabricated. Also, the testing procedure is being revised to require use of this tool.
4 Training sessions will also be conducted with the team to ensure the proficiency of
5 workers installing this device.

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

7 A. Yes.

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

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1 **BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

2 **FLORIDA POWER & LIGHT COMPANY**

3 **TESTIMONY OF CHARLES R. ROTE**

4 **DOCKET NO. 20250001-EI**

5 **MARCH 14, 2025**

6

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

8 A. My name is Charles R. Rote, and my business address is 4300 Kyoto Gardens
9 Drive, Palm Beach Gardens, Florida 33410.

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

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

13 **Q. Please summarize your educational background and professional**
14 **experience.**

15 A. I graduated from DePauw University with a bachelor’s degree in industrial
16 psychology in 1991. I subsequently earned a Master of Business
17 Administration from Pace University in New York in 1994. I am a Certified
18 Public Accountant in the state of New York. Prior to 1999, I held various
19 auditing positions at Price Waterhouse LLP and Pfizer Inc. From 1999 to 2009,
20 I worked for Rinker Materials (acquired by Cemex in 2008) in various audit,
21 accounting, and development capacities. I have been in my current role at FPL
22 since 2009 where I have responsibility for all budgeting, forecasting, regulatory
23 and internal controls activities for FPL’s fossil and solar generating assets.

1 Since 2013, I have also overseen the preparation of the Generating Performance
2 Incentive Factor (“GPIF”) filings, including testimony, exhibits, audits, and
3 discovery.

4 **Q. What is the purpose of your testimony?**

5 A. The purpose of my testimony is to report FPL’s actual 2024 performance for
6 Equivalent Availability Factors (“EAF”) and Average Net Operating Heat
7 Rates (“ANOHR”) for the GPIF generating units and to calculate the resulting
8 GPIF reward/penalties. I compared the performance of each unit to the targets
9 approved in the final Commission Order No. PSC-2024-0481-FOF-EI issued
10 November 22, 2024 for the period January through December 2024 and
11 performed the reward/penalty calculations prescribed by the GPIF Manual. My
12 testimony presents the results of these calculations: \$6,989,485 of fuel losses to
13 FPL’s customers and a GPIF penalty of \$3,499,890.

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

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

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

20 A. The steps involved in calculating the reward/penalty are provided in Exhibit
21 CRR-1. Page 2 provides the overall GPIF performance of -1.1369 points or
22 \$6,989,485 in fuel losses which represents a penalty of \$3,499,890. Page 3
23 provides the calculation of the maximum allowed incentive dollars as approved

1 by Commission Order No. PSC-13-0665-FOF-EI issued December 18, 2013.

2 The calculation of the system actual GPIF performance points is shown on
3 page 4. This page lists each GPIF unit, the unit's weighting factors, and the
4 associated GPIF unit points.

5

6 Page 5 shows the actual EAF and adjustments summary. This page lists each
7 of the GPIF units, the targets, the adjusted actual EAF and the Generating
8 Performance Incentive Points for each unit for availability as determined by
9 interpolating from the tables shown on pages 8 through 23. These tables are
10 based on the targets and target ranges previously approved by the Commission.

11

12 Continuing with Exhibit CRR-1, page 7 shows the adjustments to ANOHR.
13 Columns 2 through 4 show the target heat rate formula, the actual net output
14 factor ("NOF") and ANOHR for each GPIF unit. Since heat rate varies with
15 NOF, it is necessary to determine both the target and actual heat rates at the
16 same NOF. This adjustment provides a common basis for comparison purposes
17 and is shown numerically for each GPIF unit in columns 5 through 8. Column 9
18 contains the Generating Performance Incentive Points as determined by
19 interpolating from the tables shown on pages 8 through 23. These tables are
20 based on the targets and target ranges previously approved by the Commission.

1 **Q. Please explain the primary reason FPL will receive a penalty under the**
2 **GPIF for the January through December 2024 period.**

3 A. The primary reason that FPL will receive a penalty for the period is that the five
4 out of the 16 FPL GPIF units operated with an adjusted actual ANOHR that
5 was above the ± 75 Btu/kWh dead band.

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

7 A. St. Lucie Unit 1 operated at an adjusted actual EAF of 86.6%, compared to its
8 target of 82.7%. This results in +10.0 points, which corresponds to a GPIF
9 reward of \$2,265,739.

10

11 St. Lucie Unit 2 operated at an adjusted actual EAF of 80.4%, compared to its
12 target of 81.6%. This results in -4.0 points, which corresponds to a GPIF
13 penalty of \$764,687.

14

15 Turkey Point Unit 3 operated at an adjusted actual EAF of 78.3% compared to
16 its target of 73.3%. This results in +10.0 points, which corresponds to a GPIF
17 reward of \$1,720,854.

18

19 Turkey Point Unit 4 operated at an adjusted actual EAF of 100% compared to
20 its target of 93.6%. This results in +10.0 points, which corresponds to a GPIF
21 reward of \$2,077,954.

1 In total, the nuclear units' EAF performance results in a net GPIF reward of
2 \$5,299,860.

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

5 A. The St. Lucie Unit 1 adjusted actual ANOHR is 10,399 Btu/kWh compared to
6 its target of 10,419 Btu/kWh. This ANOHR is within the ± 75 Btu/kWh dead
7 band around the projected target; therefore, there is no GPIF reward or penalty.

8
9 The St. Lucie Unit 2 adjusted actual ANOHR is 10,259 Btu/kWh compared to
10 its target of 10,304 Btu/kWh. This ANOHR is within the ± 75 Btu/kWh dead
11 band around the projected target; therefore, there is no GPIF reward or penalty.

12
13 The Turkey Point Unit 3 adjusted actual ANOHR is 10,528 Btu/kWh compared
14 to its target of 10,548 Btu/kWh. This ANOHR is within the ± 75 Btu/kWh dead
15 band around the projected target; therefore, there is no GPIF reward or penalty.

16
17 Turkey Point Unit 4 adjusted actual ANOHR is 10,393 Btu/kWh compared to
18 its target of 10,394 Btu/kWh. This ANOHR is within the ± 75 Btu/kWh dead
19 band around the projected target; therefore, there is no GPIF reward or penalty.

20
21 In total, the nuclear units' heat rate performance results in no GPIF reward or
22 penalty.

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

2 A. \$5,299,860.

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

4 A. Regarding EAF performance, five of the 12 fossil generating units performed
5 better than their availability targets as shown on Exhibit CRR-1, page 5,
6 resulting in a combined reward of \$513,485. The other seven performed below
7 their availability target as shown on Exhibit CRR-1, page 5, resulting in a
8 penalty of \$1,008,500. Thus, the total FPL fossil units' EAF performance
9 results in a net GPIF penalty of \$495,015.

10

11 Regarding ANOHR, seven out of the 12 fossil units operated with ANOHRs
12 that were within the ± 75 Btu/kWh dead band so there were no incentive rewards
13 or penalties. The other five operated with ANOHRs that were above the ± 75
14 Btu/kWh dead band and consequently received a combined penalty of
15 \$8,304,734. Thus, the total fossil unit heat rate performance results in a net
16 GPIF penalty of \$8,304,734.

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

18 A. The net GPIF fossil availability performance penalty of \$495,015 plus the net
19 GPIF heat rate fossil performance penalty of \$8,304,734 results in a total GPIF
20 penalty for FPL's fossil units of \$8,799,749.

1 **Q.** **To recap, what is FPL’s total GPIF result for the period January through**
2 **December 2024?**

3 A. The total GPIF result for the period January through December 2024 is
4 \$6,989,485 of fuel losses and a GPIF penalty of \$3,499,890.

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

6 A. Yes.

1 **BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

2 **FLORIDA POWER & LIGHT COMPANY**

3 **TESTIMONY OF CHARLES R. ROTE**

4 **DOCKET NO. 20250001-EI**

5 **SEPTEMBER 4, 2025**

6

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

8 A. My name is Charles R. Rote, and my business address is 4300 Kyoto Gardens Drive,
9 Palm Beach Gardens, Florida 33410.

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

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

15 **Q. What is the purpose of your testimony?**

16 A. The purpose of my testimony is to present FPL's generating unit equivalent availability
17 factor (EAF) targets and average net operating heat rate (ANOHR) targets used in
18 determining the Generating Performance Incentive Factor (GPIF) for the period
19 January through December 2026.

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

3 A. Yes, I am sponsoring Exhibit CRR-2. Exhibit CRR-2 supports the development of the
4 2026 GPIF EAF and ANOHR targets. The first page of this exhibit is an index to its
5 contents. All other pages are numbered according to the GPIF Manual.

6 **Q. Please summarize the 2026 system targets for EAF and ANOHR for the units to**
7 **be considered in establishing the GPIF for FPL.**

8 A. For the period of January through December 2026, FPL projects a weighted system
9 equivalent planned outage factor (EPOF) of 6.4% and a weighted system equivalent
10 unplanned outage factor (EUOF) of 7.7% which yield a weighted system EAF target
11 of 85.9%. The targets for this period reflect planned refuelings for St. Lucie Unit 2 and
12 Turkey Point Unit 3. FPL also projects a weighted system ANOHR target of 6,794
13 Btu/kWh for the period January through December 2026. These targets represent fair
14 and reasonable values. Therefore, FPL requests that the targets for these performance
15 indicators be approved by the Commission.

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

18 A. Yes, I have. Exhibit CRR-2, pages 8 and 9, contains the information summarizing the
19 individual targets and ranges for EAF and ANOHR for each of the seventeen generating
20 units that FPL proposes to be considered as GPIF units for the period January through
21 December 2026. All of these targets have been derived utilizing the accepted
22 methodologies adopted in the GPIF Manual.

1 **Q. Please summarize FPL’s methodology for determining EAF targets.**

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

9 **Q. Please summarize FPL’s methodology for determining ANOHR targets.**

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

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

3 A. In accordance with the GPIF Manual, the GPIF units selected are responsible for no
4 less than 80% of the estimated system net generation based on economic dispatch. The
5 estimated net generation for each unit is taken from the GenTrader model, which forms
6 the basis for the projected levelized fuel cost recovery factor for the period. In this
7 case, the seventeen units which FPL proposes to use for the period January through
8 December 2026 represent the units that have at least three years of generation history
9 and are anticipated to generate 80.1% of the total forecasted system net generation
10 based on economic dispatch.

11 **Q. Do FPL's 2026 EAF and ANOHR performance targets as shown on Exhibit CRR-**
12 **2 represent reasonable levels of generation availability and efficiency?**

13 A. Yes.

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

15 A. Yes.

1 (Whereupon, prefiled direct testimony of Amin
2 Mohomed was inserted.)

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1 **BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

2 **FLORIDA POWER & LIGHT COMPANY**

3 **TESTIMONY OF AMIN MOHOMED**

4 **DOCKET NO. 20250001-EI**

5 **APRIL 2, 2025**

6
7 **Q. Please state your name, business address, employer and position.**

8 A. My name is Amin Mohomed. My business address is 700 Universe Boulevard, Juno
9 Beach, Florida 33408. I am employed by Florida Power & Light Company (“FPL” or
10 “Company”) as Assistant Controller.

11 **Q. Please summarize your educational background and professional experience.**

12 A. I graduated from Minnesota State University, Mankato in 2008 with a Bachelor of
13 Science Degree in Accounting and Economics and earned a Master of Business
14 Administration degree from the same university in 2010. From 2010 to 2017, I was
15 employed by Wilary Winn, LLC, a consulting firm based in St. Paul, Minnesota
16 providing valuation and accounting advisory services to the banking sector. From 2017
17 to 2019, I worked for FPL in the Accounting Policy & Research group. In 2019, I
18 joined the Financial Accounting Standards Board as a member of its research staff,
19 focusing on analyzing technical accounting issues and providing recommendations that
20 addressed the needs of financial statement users. I returned to FPL in 2021 as the Senior
21 Manager of Accounting Policy & Research, and in 2023, I assumed my current role of
22 Assistant Controller responsible for overseeing FPL’s general accounting functions,

1 including cost recovery clauses. I am a Certified Public Accountant (“CPA”) licensed
2 in the State of Minnesota and a member of the American Institute of CPAs.

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

4 A. The purpose of my testimony is to present the schedules necessary to support the actual
5 Fuel Cost Recovery (“FCR”) Clause and Capacity Cost Recovery (“CCR”) Clause true-
6 up amounts for the period January 2024 through December 2024.

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

9 A. Yes. Exhibit AM-1 contains the FCR-related schedules and Exhibit AM-2 contains the
10 CCR-related schedules. In addition, FCR Schedules A1 through A12 for the January
11 2024 through December 2024 period have been filed monthly with the Commission
12 and served on all parties of record in this docket. Those schedules are incorporated
13 herein by reference.

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

15 A. Unless otherwise indicated, the data are taken from the accounting books and records
16 of FPL. The books and records are kept in the regular course of the Company’s
17 business in accordance with Generally Accepted Accounting Principles, and with the
18 applicable provisions of the Uniform System of Accounts as prescribed by the
19 Commission.

20 **Q. Please summarize FPL’s final 2024 FCR and CCR net true-up amounts.**

21 A. The 2024 final net true-up for the FCR is an over-recovery of \$122,946,897 (Exhibit AM-
22 1, page 1), inclusive of interest. FPL is requesting Commission approval to include this
23 2024 FCR clause true-up over-recovery in the calculation of the FCR factors for the
24 period January 2026 through December 2026.

1 The 2024 final net true-up for the CCR clause is an over-recovery, including interest,
2 of \$11,087,054 (Exhibit AM-2, page 1). FPL is requesting Commission approval to
3 include this 2024 Clause true-up over-recovery in the calculation of the CCR factors
4 for the period January 2026 through December 2026.

5
6 Finally, FPL is requesting Commission approval to include \$47,019,343 in the
7 calculation of the FCR factors for the period January 2026 through December 2026,
8 which represents FPL's share of the 2024 Asset Optimization gains described in the
9 testimony of FPL witness Cashman and presented on page 1 of Exhibit MVC-1.

10
11 **2024 FCR FINAL TRUE-UP CALCULATION**

12 **Q. Please explain the calculation of the 2024 FCR true-up amount.**

13 A. The calculation of the FCR actual true-up by month for January 2024 through
14 December 2024 is shown on page 2 of Exhibit AM-1. The calculation of the FCR true-
15 up amount for the period follows the procedures established by this Commission as set
16 forth on Commission Schedule A2 "Calculation of True-Up and Interest Provision."

17 **Q. Though it is not included as part of the 2024 FCR true-up calculation, have you**
18 **provided a schedule showing the variances between actual and actual/estimated**
19 **FCR costs and applicable revenues for 2024?**

20 A. Yes. Exhibit AM-1, page 3 (line 52) compares the actual end of-period true-up over-
21 recovery, including interest, of \$103,916,456 (column 3) to the actual/estimated end-
22 of-period under-recovery of \$19,030,441 (column 4) resulting in a net over-recovery
23 of \$122,946,897 (column 5). Exhibit AM-1, page 3, shows a decrease in jurisdictional

1 fuel costs of \$16,964,832 (line 44) and an increase in revenues of \$104,226,831 (line
2 40), plus interest of \$1,755,235 (line 46) resulting in a net over-recovery of
3 \$122,946,897 (Line 52).

4 **Q. Please summarize the variance schedule on page 3 of Exhibit AM-1.**

5 A. FPL previously projected jurisdictional total fuel costs and net power transactions to
6 be \$2.83 billion for 2024 (Exhibit AM-1, page 3, line 44, column 4). The actual
7 jurisdictional fuel costs and net power transactions for the 2024 period are \$2.81 billion
8 (Exhibit AM-1, page 3, line 44, column 3). The resulting jurisdictional fuel costs and
9 net power transactions are \$17 million, or 0.6%, lower than previously projected
10 (Exhibit AM-1, page 3, line 44, column 5). Jurisdictional fuel revenues for 2024 are
11 \$104 million, or 3.7%, higher than previously projected (Exhibit AM-1, page 3, line
12 40, column 5).

13

14 Page 3 of Exhibit AM-1 also presents the variance on a total system basis. Total system
15 fuel costs and net power transactions were previously estimated to be about \$2.96
16 billion for 2024 (Exhibit AM-1, page 3, line 24, column 4). The actual system fuel
17 costs and net power transactions for the 2024 period are about \$2.94 billion (Exhibit
18 AM-1, page 3, line 24, column 3). The resulting fuel costs and net power transactions
19 are \$13 million, or 0.5%, lower than previously projected (Exhibit AM-1, page 3, line
20 24, column 5).

1 **Q. Please explain the variance for total system fuel costs and net power transactions**
 2 **on page 4 of Exhibit AM-1.**

3 A. Below are the primary reasons for the \$13 million (total system) variance of total fuel
 4 costs and net power transactions.

5
 6 Fuel Cost of System Net Generation: \$7 million increase (Exhibit AM-1, page 3, line
 7 2, column 5)

8
 9 The table below on pages 5 and 6 provides the detail of this variance.

Fuel Variance	2024 Final True-Up	2024 Actual/Estimated	Difference
<u>Heavy Oil</u>			
Total Dollar	\$38	\$0	\$38
Units (MMBtu)	0	0	0
\$ per Unit	0.0000	0.0000	0.0000
Variance Due to Consumption			\$0
Variance Due to Cost			\$0
Total Variance			\$0
<u>Light Oil</u>			
Total Dollar	\$20,152,921	\$13,839,692	\$6,313,230
Units (MMBtu)	1,039,491	704,833	334,658
\$ per Unit	19.3873	19.6354	(0.2481)
Variance Due to Consumption			\$6,571,150
Variance Due to Cost			(\$257,920)
Total Variance			\$6,313,230

Fuel Variance	2024 Final True-Up	2024 Actual/Estimated	Difference
<u>Coal</u>			
Total Dollar	\$22,375,083	\$17,770,574	\$4,604,509
Units (MMBtu)	6,329,062	5,103,453	1,225,609
\$ per Unit	3.5353	3.4821	0.0532
Variance Due to Consumption			\$4,267,655
Variance Due to Cost			\$336,854
Total Variance			\$4,604,509
<u>Gas</u>			
Total Dollar	\$2,890,625,714	\$2,895,109,962	(\$4,484,249)
Units (MMBtu)	742,392,223	703,079,884	39,312,339
\$ per Unit	3.8937	4.1178	(0.2241)
Variance Due to Consumption			\$161,878,539
Variance Due to Cost			(\$166,362,787)
Total Variance			(\$4,484,249)
<u>Nuclear</u>			
Total Dollar	\$145,406,079	\$144,365,476	\$1,040,603
Units (MMBtu)	300,809,249	299,286,190	1,523,059
\$ per Unit	0.4834	0.4824	0.0010
Variance Due to Consumption			\$734,672
Variance Due to Cost			\$305,931
Total Variance			\$1,040,603
<u>Total</u>			
Total Dollar	\$3,078,559,834	\$3,071,085,703	\$7,474,131
Units (MMBtu)	1,050,570,026	1,008,174,361	42,395,665
\$ per Unit	2.9304	3.0462	(0.1158)
Variance Due to Consumption			\$173,452,015
Variance Due to Cost			(\$165,977,922)
Total Variance			\$7,474,093

1 Rail Car Lease Costs: \$0.2 million decrease (Exhibit AM-1, Page 3, line 3, column 5)

2 The decrease in lease costs is primarily attributable to lower repair costs and lower
3 costs to return coal cars previously leased for use at Cedar Bay and now used at Scherer
4 3. FPL forecasted \$0.2 million for these costs by the end of 2024. However, FPL
5 entered into an agreement with Trinity Industry Leasing Co. and Georgia Power to
6 transfer the lease of the coal cars to Georgia Power in their current condition at the end
7 of the lease term; thereby avoiding the estimated repair and return expenses.

8
9 Fuel Cost of Stratified Sales: \$7.0 million decrease (Exhibit AM-1, Page 3, line 4,
10 column 5)

11 The 10% decrease in Fuel Cost of Stratified Sales is a result of a 24% increase in
12 volume offset by an average natural gas price decrease of roughly 25% for the balance
13 of 2024.

14
15 Fuel Cost of Power Sold: \$1.6 million increase (Exhibit AM-1, page 3, line 5, column
16 5)

17 The increased Fuel Cost of Power Sold is primarily attributable to higher than projected
18 unit fuel costs associated with economy power sales. The average unit fuel cost
19 attributable to economy power sales was \$0.46/MWh higher than projected, resulting
20 in a cost increase of about \$1.4 million. Additionally, FPL sold approximately 15,000
21 MWh more economy power, resulting in a volume increase of about \$0.3 million. The
22 increases were offset by a decrease of approximately \$0.1 million attributable to both

1 lower than projected fuel costs and lower than projected sales for the St. Lucie Plant
2 Reliability Exchange.

3
4 Gains from Off-System Sales: \$3.8 million increase (Exhibit AM-1, page 3, line 6,
5 column 5)

6 The increased Gains from Off-System Sales is attributable to higher than projected
7 margins on economy power sales. Margins on economy power sales averaged
8 \$1.17/MWh higher than projected, resulting in an increase of about \$3.5 million.
9 Additionally, FPL sold nearly 15,000 MWh more of economy power, resulting in an
10 increase of \$0.25 million due to volume. The combination of higher margins on
11 economy power sales and slightly higher volume of economy power sales resulted in a
12 total net increase of Gains from Off-System Sales of about \$3.8 million.

13
14 Fuel Cost of Purchased Power, Exclusive of Economy: \$8.7 million decrease (Exhibit
15 AM-1, page 3, line 7, column 5)

16 The decrease of \$8.7 million for the Fuel Cost of Purchased Power, Exclusive of
17 Economy is primarily attributable to lower than projected unit costs offset by slightly
18 higher than projected purchased power volumes associated with the Santa Rosa Power
19 Purchase Agreement (“SRPPA”). Unit costs of purchased power associated with the
20 SRPPA were \$11.66/MWh lower than projected, resulting in a cost decrease of
21 approximately \$9.4 million, and is offset by FPL purchasing about 39,000 MWh more
22 than projected in accordance with the SRPPA, resulting in a volume increase of
23 approximately \$0.9 million. The remainder of the decrease is attributable to lower than

1 projected volumes of purchased power, roughly 77,000 MWh, offset by higher than
2 projected unit costs, \$0.81/MWh, attributing to an increase of approximately \$0.2
3 million.

4
5 Energy Payments to Qualifying Facilities: \$1.0 million decrease (Exhibit AM-1,
6 page 3, line 8, column 5)

7 The decrease for Energy Payments to Qualifying Facilities is attributable to lower than
8 projected purchases and lower than projected costs from Qualifying Facilities. In total,
9 FPL purchased about 33,000 MWh less than projected, resulting in a volume decrease
10 of about \$1.4 million. The average unit fuel cost for these purchases was \$1.05 higher
11 than projected, resulting in an offsetting cost increase of about \$485,000.

12
13 Energy Cost of Economy Purchases: \$1.0 million decrease (Exhibit AM-1, page 3, line
14 9, column 5)

15 The decrease is primarily attributable to lower than projected volume of economy
16 power purchases. FPL purchased about 30,300 MWh less than projected, resulting in
17 a \$1.6 million decrease. The decrease is offset by higher than projected unit costs for
18 economy power purchases. The unit costs for economy power purchases were
19 \$5.44/MWh higher than expected, resulting in a \$0.6 million increase.

20
21 Incremental Personnel, Software, and Hardware Costs: \$39,696 increase (Exhibit AM-
22 1, page 3, line 12, column 5)

1 The increase is due to higher than estimated costs associated with additional
2 incremental personnel supporting asset optimization functions.

3 Variable Power Plant O&M Attributable to Off-System Sales: \$81,153 decrease
4 (Exhibit AM-1, page 3, line 13, column 5)

5 The decrease is attributable to lower than projected economy power sales.

6
7 Variable Power Plant O&M Avoided Due to Economy Purchases: \$14,529 decrease
8 (Exhibit AM-1, page 3, line 14, column 5)

9 The decrease is attributable to lower than projected economy power purchases.

10
11 Optimization Credits: \$10.6 million increase (Exhibit AM-1, page 3, line 15, column
12 5)

13 The increase of \$10.6 million is attributable to higher than projected gains from natural
14 gas optimization activities and renewable energy credits sales.

15 **Q. What is the increase in retail FCR revenues?**

16 A. As shown on Exhibit AM-1, page 3, line 40, actual 2024 jurisdictional FCR revenues
17 were approximately \$104 million higher than estimated. This is primarily due to
18 2,736,167,316 kWh higher than estimated jurisdictional sales (page 3, line 27, column
19 5).

1 **Q. FPL witness Cashman calculates in his testimony that FPL is entitled to retain**
2 **\$47,019,343 as its share of the 2024 Asset Optimization gains. When is FPL**
3 **requesting to recover its share of the gains, and how will this be reflected in the**
4 **FCR schedules?**

5 A. FPL is requesting recovery of its share of the 2024 Asset Optimization gains through
6 the 2026 FCR factors, consistent with how gains have been recovered in prior years.
7 FPL will include the approved jurisdictionalized amount of the gain in the calculation
8 of the 2026 FCR factors and will reflect recovery of one-twelfth of the approved
9 amount in each month's Schedule A2 for the period January 2026 through December
10 2026 as a reduction to jurisdictional fuel revenues applicable to each period.

11

12

2024 CCR FINAL TRUE-UP CALCULATION

13 **Q. Please explain the calculation of FPL's 2024 CCR net true-up amount.**

14 A. Exhibit AM-2, page 1 provides the calculation of the CCR net true-up for the period
15 January 2024 through December 2024, an over-recovery of \$11,087,054, which FPL is
16 requesting to be included in the calculation of the CCR factors for the January 2026
17 through December 2026 period. The actual end-of-period over-recovery for the period
18 January 2024 through December 2024 of \$4,684,388, shown on line 3 less the
19 actual/estimated end-of-period under-recovery for the same period of \$6,402,666
20 shown on line 7 that was approved by the Commission in Order No. PSC-2024-0481-
21 FOF_EI, results in the net true-up over-recovery for the period January 2024 through
22 December 2024 of \$11,087,054 shown on line 9.

1 **Q. Have you provided a schedule showing the calculation of the 2024 CCR actual**
2 **true-up by month?**

3 A. Yes. Exhibit AM-2, pages 2 through 4, shows the calculation of the CCR true-up for
4 the period January 2024 through December 2024 by month.

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

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

10 **Q. Have you provided a schedule showing the variances between actual and**
11 **actual/estimated capacity costs and applicable revenues for 2024?**

12 A. Yes. Exhibit AM-2 pages 5 and 6 show the actual capacity costs and applicable
13 revenues compared to actual/estimated capacity costs and applicable revenues for the
14 period January 2024 through December 2024.

15 **Q. Please explain the variances related to capacity costs.**

16 A. As shown in Exhibit AM-2, page 5, line 13, column 5, the variance related to total
17 system capacity costs is a decrease of \$2.49 million or 1.1%. Below are the primary
18 reasons for the decrease.

19

20 Transmission of Electricity by Others: \$0.5 million decrease (Exhibit AM-2, page 5,
21 line 3, column 5)

22 The decrease is primarily attributable to higher than projected transmission credits of
23 approximately \$518,000. This was offset by higher than projected purchases of

transmission service to move energy associated with purchased power agreements into FPL's service area resulted in an increase of approximately \$152,000. The balance of the decrease, approximately \$122,000, is due to lower than projected purchases of third-party transmission service used to facilitate economy power sales during the period.

Transmission Revenues from Capacity Sales: \$2.5 million increase (Exhibit AM-2, page 5, line 4, column 5)

The increase is primarily attributable to higher than projected economy power sales during the period. The increase in economy power sales resulted in higher than projected FPL transmission costs of approximately \$3,052,000. This was offset by lower than projected capacity premiums resulting in a decrease of approximately \$575,000.

Incremental Nuclear Compliance Costs O&M: \$0.1 million decrease (AM-2, page 5, line 7, column 5)

The decrease is primarily attributable to a lower Pooled Inventory Management Service fee.

Q. Please describe the variance in 2024 CCR revenues.

A. As shown on page 6, line 23, column 5, actual 2024 CCR revenues are \$2.4 million lower than projected in the actual/estimated true-up filing.

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

3 A. Yes. Schedule A12 consists of two pages that are included in Exhibit AM-2 as pages
4 16 and 17. Page 16 shows the actual capacity payments for FPL's Power Purchase
5 Agreements for the period January 2024 through December 2024. Page 17 provides
6 the short-term capacity payments for the period January 2024 through December 2024.

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

10 A. Yes. The capital structure components and cost rates used to calculate the rate of return
11 on the capital investments for the period January 2024 through December 2024 are
12 included on page 18 of Exhibit AM-2.

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

14 A. Yes.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
Final True-Up
Calculation of Net True-Up

FOR THE PERIOD OF: JANUARY 2024 THROUGH DECEMBER 2024

(1)	(2)	(3)
Line No.		2024
1	Over/(Under) Recovery for the Current Period ⁽¹⁾	\$4,132,973
2	Interest Provision ⁽²⁾	\$551,414
3	Total	<u>\$4,684,388</u>
4		
5	Actual/Estimated Over/(Under) Recovery for the Same Period	(\$6,922,416)
6	Interest Provision	\$519,750
7	Total ⁽³⁾	<u>(\$6,402,666)</u>
8		
9	Net True-Up for the period - Over/(Under) Recovery	<u>\$11,087,054</u>
10		
11	⁽¹⁾ From Page 4, Column 15, Line 8	
12	⁽²⁾ From Page 4, Column 15, Line 9	
13	⁽³⁾ Approved in FPSC Final Order PSC-2024-0481-FOF-EI	
14	Totals may not add due to rounding	

1 **BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

2 **FLORIDA POWER & LIGHT COMPANY**

3 **TESTIMONY OF AMIN MOHOMED**

4 **DOCKET NO. 20250001-EI**

5 **SEPTEMBER 4, 2025**

6
7 **Q. Please state your name, business address, employer and position.**

8 A. My name is Amin Mohomed. My business address is 700 Universe Boulevard, Juno
9 Beach, Florida 33408. I am employed by Florida Power & Light Company ("FPL" or
10 "Company") as Assistant Controller.

11 **Q. Have you previously testified in this docket?**

12 A. Yes. On April 2, 2025, I submitted direct testimony in this docket, together with
13 Exhibit AM-1 and AM-2, in support of the Fuel Cost Recovery ("FCR") Clause and
14 Capacity Cost Recovery ("CCR") final true-up for the period January 1, 2024 through
15 December 31, 2024. On July 25, 2025, I submitted direct testimony in this docket,
16 together with Exhibits AM-3 and AM-4, in support of FPL's Actual/Estimated 2025
17 FCR and CCR True-Up.

18 **Q. Have you included updates in the amended FCR actual/estimated amounts?**

19 A. Yes. The changes reflected in the amended FCR actual/estimated amounts include an
20 additional month of actual data through July 2025 and updated fuel estimates for the
21 period August 2025 through December 2025 utilizing the August 1, 2025 fuel curve.
22 These updates reduced FPL's 2025 estimated under-recovery to \$137.26 million from
23 \$216.24 million initially filed on July 25, 2025. The \$137.26 million under-recovery

1 will be recovered from customers January 2026 through December 2026.

2 **Q. Are there updates in the amended CCR actual estimated amounts?**

3 A. No. For convenience, the CCR actual/estimated amounts have been refiled with no
4 updates along with the updated FCR schedules.

5 **Q. What is the purpose of your testimony?**

6 A. The purpose of my testimony is to present for the Florida Public Service Commission
7 (“Commission”) review and approval the calculation of FPL’s amended
8 actual/estimated true-up amounts for the FCR Clause as presented in Exhibit AM-3 and
9 the CCR Clause for the period January 2025 through December 2025 as presented in
10 Exhibit AM-4.

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

13 A. Yes, I am sponsoring Exhibits AM-3 and AM-4. Exhibit AM-3 contains the FCR
14 schedules. These include Schedules E3 through E9 that provide revised estimates for
15 the period August 2025 through December 2025. FCR Schedules A1 through A9
16 provide actual data for the period January 2025 through July 2025. The actual data was
17 derived from the FCR A-Schedules A1 through A9 that are filed monthly with the
18 Commission and served on all parties, which are incorporated herein by reference. The
19 FCR schedules contained in Exhibit AM-3 also provide the calculation of the
20 actual/estimated true-up amount and actual/estimated variances for the period January
21 2025 through December 2025.

1 Exhibit AM-4 contains the CCR schedules, which provide the calculation of FPL's
2 actual/estimated true-up amount and actual/estimated variances for the period January
3 2025 through December 2025.

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

6 A. Unless otherwise indicated, the actual data is taken from the accounting books and
7 records of FPL. The books and records are kept in the regular course of the Company's
8 business in accordance with Generally Accepted Accounting Principles, as well as the
9 provisions of the Uniform System of Accounts as prescribed by this Commission.

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

12 A. The FCR actual/estimated true-up calculation compares actuals for January 2025
13 through July 2025 and revised estimates for August 2025 through December 2025 to
14 the data reflected in FPL's 2025 FCR projection approved by Order No. PSC-2024-
15 0481-FOF-EI on November 22, 2024.

16

17 The CCR actual/estimated true-up calculation compares actuals for January 2025
18 through June 2025 and revised estimates for July 2025 through December 2025 to the
19 data reflected in FPL's 2025 CCR projection for the period January 2025 through
20 December 2025, which was filed on September 5, 2024, and approved by Order No.
21 PSC-2024-0481-FOF-EI, issued on November 22, 2024.

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

3 A. The calculation of the interest provision follows the methodology used in calculating
 4 the interest provision for all cost recovery clauses, as previously approved by this
 5 Commission. The interest provision is the result of multiplying the monthly average
 6 true-up amount for the twelve-month period by the monthly average interest rate. The
 7 average interest rate for the months reflecting actual data is developed using the AA
 8 financial 30-day rates as published on the Federal Reserve website on the first business
 9 day of the current month and the subsequent month divided by two. The average
 10 interest rate for the projected months is the actual rate published on the first business
 11 day in August 2025 for FCR and July 2025 for CCR, which reflects the interest rate
 12 from the last business day in July and June 2025 respectively.

13

14 **FUEL COST RECOVERY CLAUSE**

15 **Q. Have you provided a schedule showing the calculation of the FCR 2025**
 16 **actual/estimated true-up by month?**

17 A. Yes. Exhibit AM-3, page 1 shows the calculation of the FCR actual/estimated true-up
 18 by month for the period January 2025 through December 2025.

19 **Q. Please explain the calculation of the 2025 FCR end-of-period net true-up and**
 20 **actual/estimated true-up amounts you are requesting this Commission to approve.**

21 A. Exhibit AM-3, page 1 shows the calculation of the FCR end-of-period net true-up and
 22 actual/estimated true-up amounts. The 2025 end-of-period net true-up amount is an

1 under-recovery, including interest, of \$137.26 million, (Exhibit AM-3, page 1, line 46,
2 column 13).

3 **Q. Were these calculations made in accordance with the procedures previously**
4 **approved in predecessors to this docket?**

5 A. Yes.

6 **Q. Have you provided a schedule showing the variances between the actual/estimated**
7 **amounts and the projection amounts for 2025?**

8 A. Yes. Exhibit AM-3, page 2 provides a variance calculation that compares the 2025
9 actual/estimated period data by component to the same components from the 2025
10 projection filing.

11 **Q. Please summarize the variance schedule in Exhibit AM-3.**

12 A. FPL's projection filing projected jurisdictional total fuel costs and net power
13 transactions to be \$3.11 billion (Exhibit AM-3, page 2, line 40, column 2) for 2025.
14 The actual/estimated jurisdictional total fuel costs and net power transactions are now
15 projected to be \$3.45 billion for that period (Exhibit AM-3, page 2, line 40, column 1).
16 The resulting estimated under-recovery is due to higher than projected fuel costs offset
17 by higher than projected sales and revenues. Jurisdictional total fuel costs and net
18 power transactions are estimated to be \$333.17 million, or 10.71%, higher than the
19 projected estimates (Exhibit AM-3, page 2, line 40, column 3), jurisdictional fuel
20 revenues applicable to the period are projected to be \$75.29 million, or 2.42%, higher
21 than the projected estimates (Exhibit AM-3, page 2, line 36, column 3), and the interest
22 expense is projected to be \$2.32 million (Exhibit AM-3, page 2, line 42, column 3).
23 The net impact of increased jurisdictional fuel costs and revenues for the period,

1 including interest and net of the 2024 final true-up over-recovery, results in an under-
 2 recovery of \$137.26 million. (Exhibit AM-3, page 2, line 46, column 3).

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

4 A. Below are the primary reasons for the \$313.16 million increase in total fuel costs:

5 Fuel Cost of System Net Generation: \$367.71 million increase (Exhibit AM-3, page 2,
 6 line 2, column 3)

7 The table below provides the detail of this increase

Fuel Variance	2025 Actual/Estimated	2025 Projections	Difference
<u>Heavy Oil</u>			
Total Dollar	\$150,770	\$0	\$150,770
Units (MMBTU)	12,715	0	12,715
\$ per Unit	11.8577	0.0000	11.8577
Variance Due to Consumption			\$0
Variance Due to Cost			\$150,770
Total Variance			\$150,770
<u>Light Oil</u>			
Total Dollar	\$6,913,016	\$411,583	\$6,501,433
Units (MMBTU)	366,847	22,042	344,805
\$ per Unit	18.8444	18.6727	0.1717
Variance Due to Consumption			\$6,438,436
Variance Due to Cost			\$62,997
Total Variance			\$6,501,433

1

Fuel Variance	2025 Actual/Estimated	2025 Projections	Difference
<u>Coal</u>			
Total Dollar	\$26,989,711	\$16,711,284	\$10,278,427
Units (MMBTU)	8,170,904	5,080,270	3,090,634
\$ per Unit	3.3031	3.2894	0.0137
Variance Due to Consumption			\$10,166,480
Variance Due to Cost			\$111,947
Total Variance			\$10,278,427
<u>Gas</u>			
Total Dollar	\$3,581,548,288	\$3,245,433,561	\$336,114,728
Units (MMBTU)	696,420,531	650,322,415	46,098,116
\$ per Unit	5.1428	4.9905	0.1523
Variance Due to Consumption			\$230,052,616
Variance Due to Cost			\$106,062,112
Total Variance			\$336,114,728
<u>Nuclear</u>			
Total Dollar	\$157,617,630	\$142,957,680	\$14,659,950
Units (MMBTU)	313,204,219	301,570,988	11,633,232
\$ per Unit	0.5032	0.4740	0.0292
Variance Due to Consumption			\$5,514,655
Variance Due to Cost			\$9,145,296
Total Variance			\$14,659,950
<u>Total</u>			
Total Dollar	\$3,773,219,417	\$3,405,514,108	\$367,705,308
Units (MMBTU)	1,018,175,216	956,995,715	61,179,502
\$ per Unit	3.7059	3.5585	0.1473
Variance Due to Consumption			\$252,172,187
Variance Due to Cost			\$115,533,121
Total Variance	\$3,773,219,417	\$3,405,514,108	\$367,705,308

1 Fuel Cost of Power Sold: \$30.49 million increase (Exhibit AM-3, page 2, line 5,
2 column 3)

3 The increase in Fuel Cost of Power Sold is primarily attributable to higher than
4 projected fuel costs on economy power sales. The average unit fuel cost on economy
5 power sales is now projected to be \$6.82/MWh higher than projected resulting in an
6 increase of \$22.62 million. Additionally, this increase is also due to higher than
7 projected economy power sales. FPL estimates selling approximately 332,000 MWh
8 more of economy power through 2025, resulting in an increase of \$7.72 million. The
9 combination of higher fuel costs associated with economy power sales and projected
10 higher volumes of economy power sales result in a net increase of \$30.34 million. The
11 remainder of the increase is due to higher MWh sales and higher than projected fuel
12 costs under the St. Lucie Reliability Exchange.

13
14 Gains from Off-System Sales: \$27.80 million increase (Exhibit AM-3, page 2, line 6,
15 column 3)

16 The increase in Gains from Off-System Sales is primarily attributable to higher than
17 projected margins on power sales. FPL estimates selling approximately 332,000 MWh
18 more of economy power, resulting in an increase of \$3.23 million. Additionally, FPL
19 now estimates that margins on economy power sales will be \$7.41/MWh higher,
20 resulting in an increase of \$24.57 million. The combination of the higher volume and
21 margins results in a total increase for Gains from Off-System Sales of \$27.80 million.

1 Fuel Cost of Purchased Power: \$23.13 million increase (Exhibit AM-3, page 2, line 7,
2 column 3)

3 The increase for the Fuel Cost of Purchased Power is primarily attributable to the Santa
4 Rosa Purchased Power Agreement (“PPA”) and Southern Company PPA. In April
5 2025, FPL extended the agreement with Southern Company through February 2026, to
6 purchase power from the Santa Rosa power plant, located in FPL’s Northwest region.

7 This purchase will continue to provide economic and reliability benefits for FPL
8 customers. Additionally, due to severe weather in the Florida Panhandle in January
9 2025, FPL exercised a call option, previously entered in Q4 2024, delivering over
10 100,000 MWh to ensure regional reliability during this unprecedented weather event.

11 The remainder of the increase is due to higher MWh purchases and higher than
12 projected fuel costs under the St. Lucie Reliability Exchange and Solid Waste Authority
13 purchases.

14

15 Energy Cost of Economy Purchases: \$14.51 million increase (Exhibit AM-3, page 2,
16 line 9, column 3)

17 The increase for the Energy Cost of Economy Purchases is primarily attributable to
18 higher than projected economy power purchases and higher unit costs for economy
19 power purchases. FPL now estimates to purchase approximately 84,000 MWh more
20 of economy power than projected, resulting in an increase in Energy Costs of Economy
21 Purchases of \$3.70 million. Additionally, FPL now estimates that the unit cost of
22 economy purchases will be \$46.62/MWh higher, resulting in an increase of \$10.81

1 million. The combination of higher economy purchases and higher unit costs for
2 economy power purchases results in an increase of \$14.51 million.

3

4 Variable O&M Costs Attributable to Off-System Sales: \$143,250 increase

5 (Exhibit AM-3, page 2, line 13, column 3)

6 The increase is attributable to higher than projected economy power sales.

7

8 Variable Power Plant O&M Costs Avoided due to Economy Purchases: \$40,277

9 increase (Exhibit AM-3, page 2, line 14, column 3)

10 The increase is attributable to higher than projected economy power purchases.

11

12 Optimization Credits: \$15.87 million increase (Exhibit AM-3, page 2, line 15,
13 column 3)

14 The increase for Optimization Credits is attributable to higher than projected gains from
15 activities associated with natural gas and renewable energy credit optimization
16 activities.

17

18 Lease Costs: \$2.84 million increase (Exhibit AM-3, page 2, line 3, column 3)

19 The increase in Lease Costs is primarily due to higher than projected costs resulting
20 from rail car repairs and rail car returns associated with the expiration of the current
21 lease agreement ending December 31, 2025.

1 Incremental Personnel, Software, and Hardware Costs: \$747,845 increase
 2 (Exhibit AM-3, page 2, line 12, column 3)

3 The increase in Incremental Personnel, Software, and Hardware Costs is primarily
 4 attributable to incremental personnel hired to support asset optimization functions.
 5 These personnel costs represent staffing additions to effectively manage and optimize
 6 the Company's asset portfolio.

7

8 **CAPACITY COST RECOVERY CLAUSE**

9 **Q. Have you provided a schedule showing the calculation of the CCR 2025**
 10 **actual/estimated true-up by month?**

11 A. Yes. Exhibit AM-4, page 1 provides the calculation of the CCR actual/estimated true-
 12 up by month for the period January 2025 through December 2025.

13 **Q. Please explain the calculation of the CCR 2025 actual/estimated true-up and the**
 14 **end-of-period net true-up amounts you are requesting this Commission to**
 15 **approve.**

16 A. Exhibit AM-4, page 1 shows the actual/estimated capacity costs and applicable
 17 revenues compared to the 2025 CCR projection filing for the January 2025 through
 18 December 2025 period. Jurisdictional total capacity costs are estimated to be
 19 \$8.88 million higher than the projection filing (Exhibit AM-4, page 5, line 23, column
 20 3), jurisdictional CCR revenues are projected to be \$5.15 million higher than the
 21 projection filing (Exhibit AM-4, page 5, line 28, column 3), partially offset by
 22 \$0.36 million interest owed to customers (Exhibit AM-4, page 5, line 31, column 3),

1 plus a true-up adjustment of \$0.12 million (Exhibit AM-4, page 5, line 35 plus line 36).

2 The Actual Estimated true-up under-recovery is \$3.25 million to be included in 2026
3 projections (Exhibit AM-4, page 5, lines 30 plus 31, 35 and 36, column 3).

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

6 A. Yes.

7 **Q. Please explain the variances related to capacity costs.**

8 A.## As shown in Exhibit AM-4, page 4, line 13, total system capacity costs are estimated
9 to be \$9.25 million or 7.3% higher than projected. The increase related to the
10 jurisdictional portion of these costs is \$8.88 million or a 7.3% increase from the
11 projection (page 5, line 23, column 4). Below are the primary reasons for the estimated
12 \$9.25 million increase in total system capacity costs:

13

14 Payments to Non-Cogenerators: \$13.02 million increase (Exhibit AM-4, page 4, line 1,
15 column 3)

16 The total increase for Payments to Non-Cogenerators is primarily attributable to higher
17 than projected costs of \$12.15 million associated with the extension of the Santa Rosa
18 agreement for the balance of the year. An increase of \$0.99 million is due to capacity
19 costs related to Macquarie Energy and Rainbow Energy Marketing transactions
20 executed for January and February which were not included in the projections. The
21 increase was partially offset by \$115 thousand of lower costs associated with capacity
22 shortfalls at the SWA unit during the first half of the year.

1 Transmission of Electricity by Others: \$3.69 million increase (Exhibit AM-4, page 4,
2 line 3, column 3)

3 An increase of \$3.43 million is due to incremental transmission service purchased to
4 move energy into FPL's service area during the weather event in Q1 2025. The balance
5 of the increase, \$255 thousand, is due to higher than projected purchases of third-party
6 transmission service used to facilitate higher than projected economy power sales
7 during the first half of the year.

8
9 Transmission Revenues from Capacity Sales: \$7.21 million increase (Exhibit AM-4,
10 page 4, line 4, column 3)

11 The increase is primarily attributable to revenues from capacity premiums associated
12 with power capacity sales during the first half of the year. Higher than projected
13 revenues from capacity premiums resulted in an increase of \$5.08 million. Higher than
14 projected transmission revenues from economy sales resulted in an increase of
15 \$2.13 million. Higher revenues from capacity premiums, combined with higher
16 transmission revenues from economy sales resulted in a total increase of \$7.21 million.

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

18 **A. Yes, it does.**

1 **BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

2 **FLORIDA POWER & LIGHT COMPANY**

3 **TESTIMONY OF AMIN MOHOMED**

4 **DOCKET NO. 20250001-EI**

5 **SEPTEMBER 4, 2025**

6

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

8 A. My name is Amin Mohomed. My business address is 700 Universe Boulevard,
9 Juno Beach, Florida 33408. I am employed by Florida Power & Light Company
10 ("FPL" or "Company") as Assistant Controller.

11 **Q. Have you previously testified in this docket?**

12 A. Yes.

13 **Q. What is the purpose of your testimony?**

14 A. My testimony addresses the following subjects:

- 15 • The Fuel Cost Recovery ("FCR") Clause factors for the period January 2026
16 through December 2026;
- 17 • The calculation of the jurisdictional amount of FPL's portion of the 2024
18 asset optimization gains to be recovered through the 2026 FCR factors;
- 19 • The Capacity Cost Recovery ("CCR") Clause factors for the period January
20 2026 through December 2026; and
- 21 • FPL's proposed cogeneration as-available energy ("COG-1") tariff sheets,
22 which reflect updated variable operation and maintenance expense and loss
23 factors for the company.

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

3 A. Yes. They are as follows:

4 Exhibit AM-5

- 5 • Schedules E1, E1-A, E1-C, E1-D, E1-E, E2, the RS-1 Inverted Rate
6 Calculation, and page 4, Asset Optimization Gains, which support the
7 calculation of FCR factors for January 2026 through December 2026.
- 8 • Schedule E10 presents the typical 1,000 kWh residential bill
9 comparisons.
- 10 • Schedule H1 presents the historical generating system data by fuel type.
- 11 • Pages 10 through 13, which provide the 2026 Projected Energy Losses
12 by Rate Class.
- 13 • Pages 173 through 176, which provide updated COG-1 tariff sheets.

14 Exhibit AM-6

- 15 • Pages 1 through 4 provide the calculation of 2026 CCR factors.
- 16 • Pages 5 through 10 provide the calculation of depreciation and return on
17 incremental power plant security and incremental Nuclear Regulatory
18 Commission (“NRC”) compliance capital investments.
- 19 • Page 11 provides the capital structure, components and cost rates relied
20 upon to calculate the rate of return applied to capital investments included
21 for recovery through the CCR clause for the period January 2026 through
22 December 2026.
- 23 • Pages 14 through 25 provide the calculations of stratified separation factors.

1 **Q. Do the 2026 FCR and CCR factors reflect the adjustments requested by FPL**
2 **in its Petition for base rate increase in Docket No. 20250011-EI, including the**
3 **proposed Settlement Agreement currently under consideration?**

4 A. Yes, the calculation of the amounts in the 2026 FCR and CCR factors included in
5 FPL's 2026 projections reflect the adjustments proposed in Docket No. 20250011-
6 EI as follows:

- 7 • FCR
 - 8 ○ Annual Net Metering payments made to customers for unused
 - 9 energy credits are moved from base to the FCR Clause
 - 10 ○ The customer portion of the asset optimization gains are now
 - 11 recognized in base rates instead of the FCR Clause
- 12 • CCR
 - 13 ○ Production Cost Allocation – Production costs are allocated to
 - 14 rate classes using a 4 Coincident Peak ("4CP") and 12%
 - 15 methodology.
 - 16 ○ Updated depreciation rates are applied to the 2026 projected
 - 17 CCR capital investments
 - 18 ○ The before-tax Weighted Average Cost of Capital ("WACC") to
 - 19 be applied to the 2026 projected CCR capital investments is
 - 20 based on a midpoint ROE of 10.95%

FUEL COST RECOVERY CLAUSE

Q. What adjustments are included in the calculation of the 2026 FCR factors shown on Schedule E1?

A. The 2026 FCR factors include the following adjustments: (i) an estimated net true-up, (ii) a consolidated Generating Performance Incentive Factor (“GPIF”), (iii) the jurisdictional amount associated with FPL’s share of the 2024 asset optimization gains and (iv) the cost associated with the projected 2026 Subscription Credit for the FPL SolarTogether Program.

The total net true-up amount to be included in the 2026 FCR factors is a \$137,257,698 under-recovery. This amount is reflected on line 37 of Schedule E1.

The \$137,257,698 under-recovery, divided by the projected retail sales of 128,430,086 MWh for January 2026 through December 2026, results in a charge of 0.1069 cents per kWh.

The testimony of FPL witness Rote filed on March 14, 2025, presents a GPIF penalty of \$3,499,890 for the period ending December 2024. This amount is reflected on line 39 of Schedule E1. This \$3,499,890 penalty, divided by the projected retail sales of 128,430,086 MWh for January 2026 through December 2026, results in a credit of 0.0027 cents per kWh.

1 FPL is including \$44,853,434 for the jurisdictional amount associated with its share
2 of 2024 asset optimization gains in the calculation of its 2026 FCR factors, as shown
3 on line 40 of Schedule E1. As presented and explained in the direct testimony and
4 exhibits of FPL witness Cashman, filed on April 2, 2025, in this docket, FPL's
5 activities under the asset optimization program in 2024 delivered \$125,038,686 in
6 total gains. Of these total gains, FPL is allowed to retain \$47,019,343 (system
7 amount) per Order No. PSC-13-0023-S-EI dated January 14, 2013, approved for
8 continuation, with certain modifications, by Order No. PSC-16-0560-AS-EI dated
9 December 15, 2016, and approved as an ongoing program, with further
10 modifications, by Order No. PSC-2021-0446-S-EI, dated December 2, 2021. The
11 system amount of total gains of \$47,019,343 has been allocated to the retail
12 jurisdiction based on its load ratio share of system sales for 2024. The resulting
13 jurisdictional amount to be recovered is \$44,853,434 which is calculated and shown
14 on page 4 of Exhibit AM-5. FPL will reflect recovery of one-twelfth of the
15 approved jurisdictional amount in each month's Schedule A2 for the period January
16 2026 through December 2026 as a reduction to jurisdictional fuel revenues
17 applicable to each period. This \$44,853,434, divided by the projected retail sales
18 of 128,430,086 MWh for January 2026 through December 2026, results in a charge
19 of 0.0349 cents per kWh.

20
21 FPL has included \$260,786,194 associated with the projected 2026 Subscription
22 Credit for the FPL SolarTogether Program, as shown on line 41 of Schedule E1.
23 The subscription credit is based on the program's solar power plants' forecasted

1 generation and the Subscription Credit rate as reflected in the SolarTogether tariff.

2 This \$260,786,194 divided by the projected retail sales of 128,430,086 MWh for
3 January 2026 through December 2026, results in a charge of 0.2031 cents per kWh.

4
5 Schedule E2 provides the monthly FCR factors for 2026. Schedule E-1E provides
6 the calculation of the January 2026 through December 2026 FCR factors by rate
7 group.

8 **Q. Please explain the fuel cost of stratified sales amount reflected on line 3 of**
9 **Schedule E1.**

10 A. FPL has included a projected credit of \$99,549,735 associated with stratified
11 wholesale power sales contracts in effect in 2026. The fuel costs of wholesale sales
12 are normally included in the total cost of fuel and net power transactions used to
13 calculate the average system cost per kWh for fuel adjustment purposes. However,
14 since the fuel cost of the stratified sales are not recovered on an average system cost
15 basis, an adjustment has been made to remove these costs and the related kWh sales
16 from the fuel adjustment calculation. This adjustment was performed in the same
17 manner that off-system sales are removed from the calculation, consistent with
18 Order No. PSC-97-0262-FOF-EI.

19 **Q. Please explain how FPL is addressing the amended estimated 2025 under-**
20 **recovery amount of \$137,257,698.**

21 A. FPL's amended Actual/Estimated testimony, filed in conjunction with the 2026
22 projection filing on September 4, 2025, was updated to reflect the 2025 forecasted
23 fuel curve as of August 1, 2025 as discussed in FPL witness Cashman's testimony.

1 FPL estimated a 2025 year-end under-recovery of \$137,257,698 due to the increase
2 in fuel prices since the 2025 projection filing filed on September 5, 2024. FPL
3 proposes to include the estimated 2025 under-recovery of \$137,257,698 in the 2026
4 FCR factors.

5
6 **CAPACITY COST RECOVERY CLAUSE**

7 **Q. Have you prepared a summary of the requested CCR costs for the projected**
8 **period of January 2026 through December 2026?**

9 A. Yes. Pages 1 and 2 of Exhibit AM-6 provide this summary. Total recoverable
10 capacity costs for the period January 2026 through December 2026 are \$60,446,078
11 (page 2, line 32). This includes \$68,163,396 of 2026 projected jurisdictional
12 capacity costs (page 2, line 27) and the net true-up over-recovery for 2024 and 2025
13 of \$7,717,318 (page 2, line 30 plus line 31).

14 **Q. What adjustments are included in the calculation of the 2026 CCR factors**
15 **included in Exhibit AM-6?**

16 A. The total net true-up to be included in the 2026 CCR factors is an over-recovery of
17 \$7,717,318, as shown on page 2, line 30 plus line 31. This over-recovery is
18 comprised of FPL's 2024 final net true-up over-recovery of \$11,087,053, which
19 was filed on April 2, 2025, and FPL's 2025 actual/estimated true-up under-recovery
20 of \$3,369,735 filed on July 25, 2025 and refiled on September 4, 2025.

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

3 A. Yes. Page 3 of Exhibit AM-6 provides this calculation. The demand allocation
4 factors are calculated by determining the percentage each rate class contributes to
5 the monthly system peaks. The energy allocators are calculated by determining the
6 percentage each rate class contributes to total kWh sales, as adjusted for losses.

7 **Q. Has FPL accounted for stratified wholesale power sales contracts in the**
8 **jurisdictional separation of the capacity costs?**

9 A. Yes. The separation factors used in the calculation are consistent with the FPL Ten
10 Year Power Plant Site Plan 2025-2034 filed April 1, 2025. FPL has separated the
11 production-related capacity costs based on stratified separation factors that better
12 reflect the types of generation required to serve load under stratified wholesale
13 power sales contracts. The use of stratified separation factors thus results in a more
14 accurate separation of capacity costs between the retail and wholesale jurisdictions.
15 The calculations of the stratified separation factors are provided in Exhibit AM-5
16 pages 14-25.

17 **Q. Has FPL calculated the WACC in accordance with Commission Order No.**
18 **PSC-2020-0165-PAA-EU?**

19 A. Yes. The resulting before-tax WACC to be applied to the 2026 projected CCR
20 capital investments is based on a midpoint ROE of 10.95%, which is the ROE
21 reflected in the proposed Settlement Agreement currently under consideration in
22 Docket No. 20250011-EI. The calculation of the WACC for 2026 is provided in
23 Form 8P included in Exhibit AM-6.

EFFECTIVE DATES

1

2 **Q. What are the effective dates that FPL is requesting for the new FCR factors**
3 **and CCR factors for 2026?**

4 A. FPL is requesting that the FCR and CCR factors for the period January 2026
5 through December 2026 become effective January 1, 2026.

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

7 A. Yes.

1 (Whereupon, prefiled direct testimony of
2 Jessica Husted was inserted.)

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 20250001-EI
Fuel and Purchased Power Cost Recovery Clause
Direct Testimony of
Brittnee Baker
(2024 Final True-Up)
on behalf of
Florida Public Utilities Company

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Q. Please state your name and business address.

A. My name is Brittnee Baker and my business address is 500 Energy Lane, Dover DE 19702.

Q. By whom are you employed?

A. I am employed by Chesapeake Utilities Corporation, the parent company of Florida Public Utilities Company as a Regulatory Analyst III.

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

A. I received a Bachelor of Science degree in Accounting from Johnson & Wales University. I have been employed with Chesapeake Utilities since 2018. I was hired as a Staff Accountant in 2018 before moving into the regulatory department in 2024. This role includes regulatory analysis and filings before the Florida Public Service Commission ("FPSC" or "Commission") for FPUC.

Q. Have you ever testified before the FPSC?

A. Yes. I have previously provided written, pre-filed testimony in the Company's annual Fuel proceeding, Docket No. 20240001-EI.

Q. What is the purpose of your testimony?

1 A. The purpose of my testimony is to present the calculation of the final remaining
2 true-up amounts for the period January 2024 through December 2024.

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

4 A. Yes. Exhibit (BB-1) consists of Schedules A, E1-B and C-1 for the Consolidated
5 Electric Division. These schedules were prepared from the records of the
6 company.

7 **Q. What has FPUC calculated as the final remaining true-up amounts for the**
8 **period January 2024 through December 2024?**

9 A. For the Consolidated Electric Division the final remaining true-up amount is an
10 over recovery of \$3,131,443.

11 **Q. How was this amount calculated?**

12 A. It is the difference between the actual end of period true-up amount for the
13 January through December 2024 period and the total true-up amount to be
14 collected or refunded during the January 2025 - December 2025 period.

15 **Q. What was the actual end of period true-up amount for January - December**
16 **2024?**

17 A. For the Consolidated Electric Division it was \$7,826,120 over recovery.

18 **Q. What was the Commission-approved amount to be collected or refunded**
19 **during the January 2025 – December 2025 period?**

20 A. A consolidated over-recovery of \$4,694,677 to be refunded.

21 **Q. Does the Company anticipate requiring a midcourse adjustment for 2025?**

22 A. No, not at this time. The Company believes, based on the estimates in our 2025
23 Projection filing, that any over/under-recovery will be within the 10% provision

1 of total revenues by year end 2025. The Company will closely monitor the 2025
2 results and file a midcourse correction when necessary.

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

4 **A.** Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20250001-EI: Fuel and Purchased Power Cost Recovery Clause with
generating performance incentive factor.

Direct Testimony of Jessica Husted (Estimated/Actual)

On Behalf of Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is Jessica Husted. My business address 1635 Meathe Blvd., West Palm
Beach, FL 33411.

Q. By whom are you employed?

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

Q. Describe briefly your education and relevant professional background.

A. I received a Bachelor of Science in Accounting and Business Administration and a
Master of Accounting from Nova Southeastern University. I have been employed
with Chesapeake Utilities since 2014. I worked in the internal audit department as a
Manager, Internal Audit, where I managed and performed various operational and
financial audits and testing to ensure compliance with Sarbanes Oxley requirements,
prior to moving into the regulatory department in 2025. This role includes
regulatory analysis and filings before the Florida Public Service Commission
("FPSC" or "Commission") for FPUC.

Q. Have you previously testified in this Docket?

A. No, I have not testified in this docket but I have previously provided pre-filed written
testimony in Docket No. 20250010-EI.

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

A. I will briefly describe the basis for the Company's computations made in preparation

1 of the schedules being submitted in this docket.

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

4 A. I am attaching Schedules E1-A, E1-B, and E1-B1 as part of Exhibit JH-1. Schedule
5 E1-B shows the Calculation of Purchased Power Costs and Calculation of True-Up
6 and Interest Provision for the period January 2025 – December 2025 based on 6
7 Months Actual and 6 Months Estimated data.

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

9 A. The schedules were completed by me.

10 **Q. What was the final remaining true-up amount for the period January 2024 –**
11 **December 2024?**

12 A. The final remaining true-up amount was an over-recovery of \$3,131,443.

13 **Q. What is the estimated true-up amount for the period January 2025 – December**
14 **2025?**

15 A. The estimated true-up amount is an over-recovery of \$80,530.

16 **Q. What is the total true-up amount estimated to be refunded for the period**
17 **January 2026 – December 2026?**

18 A. The Company estimates it will refund \$3,211,973 for the period January 2026 –
19 December 2026.

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

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

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

2 A. Yes. FPUC is continuing to explore both Solar Photovoltaic (solar) and Combined
3 Heat and Power (CHP) technologies with the goal of providing low cost, resilient
4 and reliable energy to customers. Solar opportunities are being explored in both the
5 Northeast and Northwest Divisions and are under consideration at this time. In our
6 Northeast Division, significant effort has been focused on the development of a
7 second CHP on Amelia Island. This project will be similar in size and operation to
8 the existing Eight Flags Energy project that began commercial operation in 2016.
9 Amelia Island Energy (AIE), as it will be named, will be located approximately one
10 mile from Eight Flags Energy at a separate mill on Amelia Island. This CHP will
11 provide electrical energy to the FPUC grid and thermal energy in the form of
12 steam/hot water to the mill. Preliminary engineering has been completed, operating
13 agreements and air permitting have been completed at this time. AIE will provide
14 low cost energy to our customers while improving the resiliency and reliability to the
15 FPUC grid on Amelia Island. In addition to CHP possibilities, FPUC has been
16 investigating how the use of Renewable Natural Gas (RNG) and Hydrogen as future
17 fuel sources for generation assets may provide benefits in the future. The markets for
18 both RNG and Hydrogen are still developing, however, both have the potential to
19 provide environmental benefits compared to existing fuel sources. Although there are
20 currently some operational and cost challenges being addressed within the generation
21 community, it is important that FPUC continue to be involved in the investigation
22 and development of these resources and the long-term benefits that are possible.
23 Also, FPUC engaged with FPL in the review of the transmission agreements and

1 infrastructure currently in place between the two companies. These discussions led to
2 opportunities to change the delivery points at four of the five substations in the
3 Northwest Florida Division, which could reduce purchased costs to FPUC. The
4 acquisition of the substations was approved in the company's last rate case
5 proceeding in Docket No. 20240099-EI and is expected to be completed by
6 December 2026.

7 **Q. Has the company incurred any costs during the preliminary stages of these**
8 **projects?**

9 A. Yes, the Company has engaged the consulting firms of Pierpont and McLelland LLC
10 and Sterling Energy Services LLC as well as the law firm of Gunster, Yoakley, and
11 Stewart, P.A. for their experienced in the aforementioned processes. The Company
12 incurred consulting and legal fees linked to these projects amounting to \$65,713 in
13 2024 and \$73,862 through June of 2025. We roughly estimate to spend another
14 \$39,000 by year-end.

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

16 A. It is anticipated that decisions can be finalized in 2025. Commercial operation should
17 occur within 1.5 years of ordering the major equipment.

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

19 A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20250001-EI: Fuel and purchased power cost recovery clause with
generating performance incentive factor.

2026 Projection Direct Testimony of Jessica Husted

On Behalf of Florida Public Utilities Company

Q. Please state your name and business address.

A. My name is Jessica Husted. My business address 1635 Meathe Blvd., West Palm
Beach, FL 33411.

Q. By whom are you employed?

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

Q. Describe briefly your education and relevant professional background.

A. I received a Bachelor of Science in Accounting and Business Administration and a
Master of Accounting from Nova Southeastern University. I have been employed
with Chesapeake Utilities since 2014. I worked in the internal audit department as a
Manager, Internal Audit, where I managed and performed various operational and
financial audits and testing to ensure compliance with Sarbanes Oxley requirements,
prior to moving into the regulatory department in 2025. This role includes
regulatory analysis and filings before the Florida Public Service Commission
("FPSC" or "Commission") for FPUC.

Q. Have you previously testified in this Docket?

A. Yes, I have testified in this Docket.

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

A. My testimony will establish the "true-up" collection amount, based on actual January

1 2025 through June 2025 data and projected July 2025 through December 2026 data
2 to be collected or refunded during January 2026 – December 2026. My testimony
3 will also summarize the computations that are contained in composite exhibit JH-2
4 supporting the January through December 2026 projected levelized fuel adjustment
5 factors for its consolidated electric divisions.

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

8 A. I am attaching Schedules E1, E1-A, E2, E7, E8, and E10 as part of Exhibit JH-2,
9 which is appended to my testimony.

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

11 A. Yes, the schedules were completed by me.

12 **Q. What was the final remaining true-up amount for the period January 2024 –**
13 **December 2024?**

14 A. The final remaining true-up amount was an over-recovery of \$3,131,443.

15 **Q. What is the estimated true-up amount for the period January 2025 – December**
16 **2025?**

17 A. The estimated true-up amount is an over-recovery of \$80,530.

18 **Q. What is the total true-up amount estimated to be refunded for the period**
19 **January 2026 – December 2026?**

20 A. The Company estimates it will refund \$3,211,973 for the period January 2026 –
21 December 2026.

22 Q. .

23 **Q. Did you include costs in addition to the costs specific to purchased fuel in the**

1 **calculations of your true-up and projected amounts?**

2 A. Yes, included with our fuel and purchased power costs are charges for contracted
3 consultants and legal services that are directly fuel-related and appropriate for
4 recovery in the fuel and purchased power clause. FPUC engaged Sterling Energy
5 Services, LLC. (“Sterling”) and Pierpont and McClelland (“Pierpont”) for assistance
6 in the development and enactment of projects/programs designed to reduce their
7 purchased power rates to its customers. The associated legal and consulting costs,
8 included in the rate calculation of the Company’s 2026 Projection factors, were not
9 included in expenses during the last FPUC consolidated electric base rate proceeding
10 and are not being recovered through base rates. Mr. Cutshaw addresses these project
11 assignments more specifically in his testimony.

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

14 A. Consistent with the Commission’s policy set forth in Order No. 14546, issued in
15 Docket No. 850001-EI-B, on July 8, 1985, the other fuel related costs included in the
16 fuel clause are directly related to purchased power, have not been recovered through
17 base rates. Specifically, consistent with item 10 of Order 14546, the costs the
18 Company has included are fuel-related costs that were not anticipated or included in
19 the cost levels used to establish the current base rates. Similar expenses paid to
20 Christensen and Associates associated with the design for a Request for Proposals of
21 purchased power costs, and the evaluation of those responses, were deemed
22 appropriate for recovery by FPUC through the fuel and purchased power clause in
23 Order No. PSC-05-1252-FOF-EI, Item II E, issued in Docket No. 050001-EI.

1 Additionally, in more recent Docket Nos. 20180001-EI, 20190001-EI, 20200001-EI,
2 20210001-EI, 20220001-EI, 20230001-EI and 20240001-EI, the Commission
3 determined that many of the costs associated with the legal and consulting work
4 incurred by the Company as fuel related, particularly those costs related to the
5 purchase power agreement review and analysis, were recoverable under the fuel
6 clause. As the Commission has recognized time and again, the Company simply does
7 not have the internal resources to pursue projects and initiatives designed to produce
8 purchased power savings without engaging outside assistance for project analytics
9 and due diligence, as well as negotiation and contract development expertise.
10 Likewise, the Company believes that the costs addressed herein are appropriate for
11 recovery through the fuel clause.

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

14 A. The total fuel adjustment factor as shown on line 43, Schedule E-1 is **7.580¢** per
15 KWH.

16 **Q. Please advise what a residential customer using 1,000 KWH will pay for the**
17 **period January - December 2026 including base rates, conservation cost**
18 **recovery factors, gross receipts tax and fuel adjustment factor and after**
19 **application of a line loss multiplier.**

20 A. As shown on consolidated Schedule E-10 in Composite Exhibit Number JH-2, a
21 residential customer using 1,000 KWH will pay **\$163.42**. This is a decrease of **\$0.38**
22 below the previous period.

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

Docket No. 20250001-EI

1 A. Yes.

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

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

**DOCKET NO. 20250001-EI: FUEL AND PURCHASED POWER COST RECOVERY
CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR**

2026 Projection Testimony of P. Mark Cutshaw
On Behalf of
Florida Public Utilities Company

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

2 A. My name is P. Mark Cutshaw, 780 Amelia Island Parkway, Fernandina Beach,
3 Florida 32034.

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

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

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

8 A. I graduated from Auburn University in 1982 with a B.S. in Electrical Engineering.
9 My electrical engineering career began with Mississippi Power Company in June
10 1982. I spent nine years with Mississippi Power Company and held positions of
11 increasing responsibility that involved budgeting, as well as operations and
12 maintenance activities at various locations. I joined FPUC in 1991 as Division
13 Manager in our Northwest Florida Division and have since worked extensively in
14 both the Northwest Florida and Northeast Florida divisions. Since joining FPUC,
15 my responsibilities have included all aspects of budgeting, customer service,
16 operations and maintenance. My responsibilities also included involvement with
17 Cost of Service Studies and Rate Design in other rate proceedings before the

Docket No. 20240001-EI

1 Commission as well as other regulatory issues. During January 2024, I moved into
2 my current role as Manager, Electric Operations for the Northeast Florida Division.

3 **Q. Have you previously testified before the Florida Public Service Commission**
4 **(“Commission”)?**

5 A. Yes, I’ve provided testimony in a variety of Commission proceedings, including the
6 Company’s 2014 rate case, addressed in Docket No. 20140025-EI, as well as
7 rebuttal testimony in Docket No. 20180061-EI and numerous annual proceedings
8 for Fuel and Purchased Power Cost Recovery. Most recently, I provided testimony
9 in Docket No. 20250010 in the Storm Protection Plan and Cost Recovery
10 proceedings.

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

12 A. My direct testimony addresses several aspects of the purchased power cost for our
13 FPUC electric customers. This includes activities to investigate the potential for
14 reduced purchase power costs, execution/amendment of purchased power
15 agreement(s) with Florida Power & Light (“FPL”), billing of purchased power cost
16 to our industrial customers, Combined Heat and Power (“CHP”) generation supply
17 located on Amelia Island and investigation into the opportunities of energy provided
18 from solar and battery installations.

19 **Q. Do natural gas costs have a significant impact on the overall cost of purchased**
20 **power for FPUC?**

21 A. Yes, because FPUC does not own its own generation, it purchases the power it needs
22 to serve its customers from larger, generating utilities. At present, FPUC purchases
23 the majority of the power it needs to serve its customers from FPL. The majority of
24 electricity generated in Florida is generated by natural gas fueled generating

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1 facilities. As such, the cost of natural gas directly impacts the cost of power
2 purchased by FPUC.

3 **Q. Has FPUC taken steps to ensure more accurate cost projections based on**
4 **activity in the natural gas markets?**

5 A. Yes. FPUC, being predominately a natural gas utility, has utilized information from
6 both inside the Company and other external sources to carefully monitor the natural
7 gas markets. Based on the information gained, the Company forecasts 2026 natural
8 gas costs and includes that information in its purchased power cost projections.

9 **Q. What is the status of the purchase power agreements in place with FPL?**

10 A. The previous agreement for our Northwest Florida Division with FPL became
11 effective January 1, 2020, with a termination date of December 31, 2026, unless
12 extended by FPUC. The previous agreement for our Northeast Florida Division with
13 FPL became effective January 1, 2018, was amended in 2019 and was scheduled to
14 terminate December 31, 2026, unless extended by FPUC. During 2023, FPUC and
15 FPL engaged in discussions with a goal of combining the separate purchased power
16 agreements into a single agreement, which would continue to provide reliable, cost
17 effective purchased power to FPUC for its customers. The combined purchased
18 power agreement was developed, executed and became effective on July 1, 2024,
19 replacing the two prior agreements for the each of FPUC's divisions.

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

23 A. In addition to consolidation of the purchased power agreements, FPUC also engaged
24 with FPL in the review of the transmission agreements and infrastructure currently

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1 in place between the two companies. These discussions led to opportunities to
2 change the delivery points at four of the five substations in the Northwest Florida
3 Division, which could reduce purchased power costs to FPUC.

4 **Q. What changes are anticipated to the transmission agreements in the Northwest**
5 **Florida Division?**

6 A. Under the current transmission agreement for the Northwest Florida Division, the
7 interconnection point between FPUC and FPL is located at the low voltage side of
8 the substation transformer. Based upon the location of the interconnection point, it
9 was necessary for FPL to pass along substation cost associated with providing
10 purchased power to FPUC in the form of a distribution charge which was
11 incorporated into the purchased power cost. In relocating the interconnection point
12 to the high voltage side of the substation transformer, the additional distribution cost
13 was no longer required for four of the five substations which helps reduce purchased
14 power cost. The fifth substation is configured in such a way that two customers are
15 provided service from the same transformer which would not allow the relocation
16 of the interconnection point. The distribution charge at this substation will continue.

17 **Q. Is FPUC proposing any changes to the way purchased power costs are allocated**
18 **to its two industrial customers?**

19 A. No. Changes occurred in 2025 which allowed a bill to be issued on the first business
20 day of every month. There are not additional changes planned during 2026.

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

3 A. Yes. FPUC continues to work with consultants, as well as project developers, to
4 identify new projects and opportunities that can lead to increased energy resiliency
5 and reduced fuel costs for our customers. We also continue to analyze the feasibility
6 of energy production and supply opportunities that have been on our planning
7 horizon for some time and noted in prior fuel clause proceedings, namely additional
8 Combined Heat and Power (CHP) projects, potential Solar Photovoltaic (“PV”) projects
9 and associated utility scale battery projects. More specifically, Pierpont &
10 McLelland has been engaged to perform analysis and provide consulting services
11 for FPUC as it relates to the structuring of, and operation under, the Company’s
12 power purchase agreements with the purpose of identifying measures that will
13 minimize cost increases and/or provide opportunities for cost reductions. They have
14 also been involved in the structuring of the most effective measures to ensure a
15 reliable and resilient system on Amelia Island which may include additional
16 transmission lines to the Island as well as using existing generation and the addition
17 of new natural gas fired generation. Locke Lord is a law firm with particular
18 expertise in the regulatory requirements of the Federal Energy Regulatory
19 Commission. Attorneys with the firm have provided legal guidance and oversight
20 regarding the contracts and regulatory requirements for generation and transmission-
21 related issues for the Northeast Florida Division. The Company’s in-house
22 experience in these areas is limited; thus, without this outside assistance, the

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Company's ability to pursue potential purchased power savings opportunities would be limited, as would its ability to properly evaluate proposals to meet our generation and transmission needs and ensure compliance with federal regulatory requirements. Sterling Energy and Christensen Associates have been involved to assist the Company in the most cost-effective means of incorporating additional energy sources, such as power available from certain industrial customers, existing and new Combined Heat and Power ("CHP") capability and improvements in the transmission system to Amelia Island to improve the reliability/resiliency on Amelia Island and further reduce the overall purchased power impact to all FPUC customers. In addition to CHP possibilities, FPUC has been investigating how the use of Renewable Natural Gas (RNG) and Hydrogen as future fuel sources for generation assets may provide benefits in the future. The markets for both RNG and Hydrogen are still developing, however, both have the potential to provide environmental benefits compared to existing fuel sources. Although there are currently some operational and cost challenges being addressed within the generation community, it is important that FPUC continue to be involved in the investigation and development of these resources and the long term benefits that are possible.

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

A. Yes. At the moment, FPUC has put on hold any movement on additional CHP projects awaiting information on what ITC and PTC legislation may be issued. Both of these are important components of making a CHP facility viable. However, the success of the Eight Flags project has sparked interest in other CHP opportunities

on Amelia Island and nearby. When coupled with industrial expansion, the already quantifiable benefits of the existing projects have piqued the interest of others to contemplate development of a new CHP-based projects. FPUC was actively involved in the initial analysis, development and engineering of a possible new projects that would support the existing industry. Significant efforts went into the evaluation of a CHP project, similar to Eight Flags, would be located on Amelia Island and would allow the customer, along with transmission line upgrades, to have additional reliability and resilience to its electricity supply for industry and possibly supply customer on Amelia Island. A second CHP project would provide electricity, high pressure steam and hot water for an area industrial customer which is a critical component to the success of the customer. Preliminary engineering, financial modeling and Florida Department of Environmental Protection permitting for one of the projects were completed for these possible CHP units. Although the final agreements and structure of the proposed CHP projects have not yet been finalized.

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

A. Yes. FPUC continues to assess the feasibility of smaller PV systems within the FPUC electric service territory. Based on the results from the analysis, the economic feasibility of smaller PV installations has been difficult to achieve due to many different factors but work continues to investigate alternatives to improve the feasibility. At this time, FPUC is investigating opportunities involving larger PV installations which have proved to be more economically feasible. Not only will this increase the renewable energy available to FPUC, the cost is expected to

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1 complement the overall purchased power portfolio which will provide additional
2 benefits to FPUC customers. The new “Agreement” with FPL does have provisions
3 that allow for the development of PV installations by FPUC and provides for the
4 possibility of a partnership between the parties that would allow for the development
5 of a PV project.

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

11 **Q. Does this include your testimony?**

12 **A. Yes.**

1 (Whereupon, prefiled direct testimony of Zel
2 D. Jones-Phillips was inserted.)

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**BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION**

**DOCKET NO. 20250001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY**

**2024 FINAL TRUE-UP
TESTIMONY AND EXHIBITS**

ZEL D. JONES

FILED: APRIL 2, 2025

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

ZEL D. JONES

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

A. My name is Zel D. Jones. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "Company") in the position of Manager, Rates in the Regulatory Affairs department.

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

A. I received a Bachelor of Science degree in Civil Engineering with a concentration in Environmental Science from Tennessee State University in 2002, and I received a Master of Business degree in 2006 from City University of Seattle in 2006. I joined Tampa Electric in 2011 as the Environmental and Water Systems Engineer at the Big Bend Power Station in Apollo Beach, Florida. In December 2019, I joined the Outage & Project Management (O&PM)

1 Department as a Project Engineer. I became a Project
2 Manager within the same department in 2020 and managed
3 capital projects for Big Bend and Bayside Power Stations.
4 In 2022, I became the Capital Program Lead at Bayside
5 Power Station - overseeing the capital program budget. I
6 joined the Regulatory Affairs Department in October 2023
7 as a Manager, Rates. My current duties entail managing
8 cost recovery for fuel and purchased power, interchange
9 sales, capacity payments and approved environmental
10 projects. I have over 13 years of electric utility
11 experience in power plant operations, operational
12 environmental compliance, large capital project and
13 program management.

14
15 **Q.** What is the purpose of your testimony?
16

17 **A.** The purpose of my testimony is to present, for the
18 Commission's review and approval, the final true-up
19 amounts for the period January 2024 through December 2024
20 for the Fuel and Purchased Power Cost Recovery Clause
21 ("Fuel Clause") and the Capacity Cost Recovery Clause
22 ("Capacity Clause"), as well as the Asset Optimization
23 Mechanism gain sharing allocation for the period.
24

25 **Q.** What is the source of the data which you will present by

1 way of testimony or exhibit in this process?

2

3 **A.** Unless otherwise indicated, the actual data is taken from
4 the books and records of Tampa Electric. The books and
5 records are kept in the regular course of business in
6 accordance with generally accepted accounting principles
7 and practices and provisions of the Uniform System of
8 Accounts as prescribed by the Florida Public Service
9 Commission ("Commission").

10

11 **Q.** Have you prepared an exhibit in this proceeding?

12

13 **A.** Yes. Exhibit No. ZDJ-1, consisting of four documents which
14 are described later in my testimony, was prepared under
15 my direction and supervision.

16

17 **Capacity Cost Recovery Clause**

18 **Q.** What is the final true-up amount for the Capacity Clause
19 for the period January 2024 through December 2024?

20

21 **A.** The final true-up amount for the Capacity Clause for the
22 period January 2024 through December 2024 is an under-
23 recovery of \$8,961,534.

24

25 **Q.** Please describe Document No. 1 of your exhibit.

1 **A.** Document No. 1, page 1 of 4, entitled "Tampa Electric
2 Company Capacity Cost Recovery Clause Calculation of
3 Final True-up Variances for the Period January 2024
4 Through December 2024", provides the calculation for the
5 final under-recovery of \$8,961,534. The actual capacity
6 cost under-recovery, including interest, was \$20,198,503,
7 for the period January 2024 through December 2024 as
8 identified in Document No. 1, pages 1 and 2 of 4. This
9 amount, less the \$11,236,969, actual/estimated under-
10 recovery approved in Order No. PSC-2024-0481-FOF-EI
11 issued on November 22, 2024, results in a final under-
12 recovery of \$8,961,534.

13
14 **Fuel and Purchased Power Cost Recovery Clause**

15 **Q.** What is the final true-up amount for the Fuel Clause for
16 the period January 2024 through December 2024?

17
18 **A.** The final Fuel Clause true-up for the period January 2024
19 through December 2024 is an over-recovery of \$32,216,179.
20 The actual fuel cost over-recovery, including interest,
21 was \$60,647,508, for the period January 2024 through
22 December 2024. This \$60,647,508, amount, less the
23 \$28,431,329, over-recovery included in the company's
24 actual/estimated projection approved in Order No. PSC-
25 2024-0481-FOF-EI issued November 22, 2024, in Docket No.

1 20240001-EI, results in a net over-recovery amount for
2 the period of \$32,216,179.

3
4 **Q.** Please describe Document No. 2 of your exhibit.

5
6 **A.** Document No. 2 is entitled "Tampa Electric Company Final
7 Fuel and Purchased Power Over/(Under) Recovery for the
8 Period January 2024 Through December 2024." It shows the
9 calculation of the final fuel over-recovery of
10 \$32,216,179.

11
12 Line 1 shows the total company fuel costs of \$550,230,252,
13 for the period January 2024 through December 2024. The
14 jurisdictional amount of total fuel costs is
15 \$550,230,252, as shown on line 2. This amount is compared
16 to the jurisdictional fuel revenues applicable to the
17 period on line 3 to obtain the actual over-recovered fuel
18 costs for the period, shown on line 4. The resulting
19 \$176,293,514, over-recovered fuel costs for the period,
20 adjustments, interest, true-up collected, and the prior
21 period true-up shown on lines 5 through 8 respectively,
22 constitute the actual over-recovery amount of
23 \$60,647,508, shown on line 9. The \$60,647,508, actual
24 over-recovery amount less the \$28,431,329, over-recovery
25 included in the company's actual/estimated projection

1 recovery amount and shown on line 10, results in a final
2 net over-recovery amount of \$32,216,179, for the period
3 January 2024 through December 2024, as shown on line 11.
4

5 **Q.** Please describe Document No. 3 of your exhibit.
6

7 **A.** Document No. 3 is entitled "Tampa Electric Company
8 Calculation of True-up Amount Actual vs. Mid-course
9 Estimates for the Period January 2024 Through December
10 2024." It shows the calculation of the actual under-
11 recovery compared to the estimate for the same period.
12

13 **Q.** What was the total fuel and net power transaction cost
14 variance for the period January 2024 through December
15 2024?
16

17 **A.** As shown on line A6 of Document No. 3, the fuel and net
18 power transaction cost is \$8,077,914, higher than the
19 amount originally estimated.
20

21 **Q.** What was the variance in jurisdictional fuel revenues for
22 the period January 2024 through December 2024?
23

24 **A.** As shown on line C3 of Document No. 3, the company
25 collected \$18,976,454, or 2.7 percent greater

jurisdictional fuel revenues than originally estimated.

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

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

Asset Optimization Mechanism

Q. Was Tampa Electric's sharing of Asset Optimization Mechanism gains allocated in accordance with FPSC Order No. PSC-2017-0456-S-EI, issued in Docket Nos. 20170210-EI and 20160160-EI, on November 27, 2017?

A. Yes. As shown in the testimony and exhibit of Tampa Electric witness John C. Heisey filed contemporaneously in this docket, the sharing of Asset Optimization Mechanism gains was allocated in accordance with FPSC Order PSC-2017-0456-S-EI. As a result of the company's Asset Optimization Mechanism activities during 2024, the total gains were \$11,441,752. Under the sharing mechanism, Tampa Electric customers receive \$7,620,876, and the company earned an incentive of \$3,820,876.

1 Customers received the gains from these transactions
2 during 2024, and Tampa Electric requests Commission
3 approval to collect the company's \$3,820,876 incentive in
4 its 2026 fuel factors.

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

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8 **A.** Yes, it does.
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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20250001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

ACTUAL/ESTIMATED TRUE-UP
JANUARY 2025 THROUGH DECEMBER 2025

TESTIMONY AND EXHIBIT
OF
ZEL D. JONES

FILED: JULY 25, 2025
REVISED: SEPTEMBER 4, 2025

TAMPA ELECTRIC COMPANY
DOCKET NO. 20250001-EI
FILED: 7/25/2025
REVISED: 9/4/2025

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

ZEL D. JONES

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

A. My name is Zel D. Jones. My business address is 3600 Midtown Drive, Tampa, Florida 33607. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Rates in the Regulatory Affairs department.

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

A. I received a Bachelor of Science degree in Civil Engineering with a concentration in Environmental Science from Tennessee State University in 2002, and I received a Master of Business degree in 2006 from City University of Seattle in 2006. I joined Tampa Electric in 2011 as the Environmental and Water Systems Engineer at the Big Bend Power Station in Apollo Beach, Florida. In December 2019, I joined the Outage & Project Management (O&PM) Department as a Project Engineer. I became a Project

1 Manager within the same department in 2020 and managed
2 capital projects for Big Bend and Bayside Power Stations.
3 In 2022, I became the Capital Program Lead at Bayside
4 Power Station - overseeing the capital program budget. I
5 joined the Regulatory Affairs Department in October 2023
6 as a Manager, Rates. My current duties entail managing
7 cost recovery for fuel and purchased power, interchange
8 sales, capacity payments and approved environmental
9 projects. I have over 14 years of electric utility
10 experience in power plant operations, operational
11 environmental compliance, large capital project and
12 program management.

13
14 **Q.** Have you filed testimony in this docket this year detailing
15 the Company's 2025 true-up amounts to be recovered in the
16 2026 projection period?

17
18 **A.** Yes, I filed testimony on July 25, 2025, with an exhibit
19 detailing the Company's calculation of the January 2025
20 through December 2025 fuel and purchased power and capacity
21 true-up amounts to be recovered in the January 2026 through
22 December 2026 projection period.

23
24 **Q.** What is the purpose of this direct testimony?
25

1 **A.** The purpose of this testimony is to present a revision to
2 the Company's calculation of the January 2025 through
3 December 2025 fuel and purchased power and capacity
4 actual/estimated true-up amounts to be recovered in the
5 January 2026 through December 2026 projection period, for
6 Commission review and approval. Natural gas prices have
7 continued to decline since the company's July 25, 2025
8 filing. As a result, Tampa Electric is updating its
9 Actual/Estimate filing to reflect the latest natural gas
10 prices. Tampa Electric is also updating its 2025 fuel and
11 purchased power costs, as well as capacity costs with
12 July actuals for a filing that is based on seven months
13 of actual data and five months of estimated data. This
14 information will be used in the determination of the 2026
15 fuel and purchased power and capacity cost recovery
16 factors.

17
18 **Q.** Have you prepared an exhibit to support your direct
19 testimony?

20
21 **A.** Yes, I have prepared Exhibit No. ZDJ-2, which consists of
22 two documents. Document No. 1 includes a revision to
23 Schedules E1-A, E1-B, E-2, E-3, E-4, E-5, E-6, E-7, E-8,
24 and E-9, which provide the actual/estimated fuel and
25 purchased power cost recovery true-up amount for the

1 period January 2025 through December 2025. Document No.
2 2 provides a revision to the actual/estimated capacity
3 schedules and the cost recovery true-up amount for the
4 period January 2025 through December 2025.

5
6 **Fuel and Purchased Power Cost Recovery Factors**

7 **Q.** What has Tampa Electric calculated as the revised estimated
8 net true-up amount for the current period to be applied in
9 the January 2026 through December 2026 fuel and purchased
10 power cost recovery factors?

11
12 **A.** The revised estimated net true-up amount for 2025 to be
13 applied in January 2026 through December 2026 fuel and
14 purchased power cost recovery factors is an over-recovery
15 of \$14,653,914.

16
17 **Q.** How does the revised estimated net true-up amount for 2025
18 compare to the estimated net true-up amount for 2025 filed
19 by the company on July 25, 2025?

20
21 **A.** The net effect of this change is to reduce total
22 jurisdictional fuel and net power transaction costs by
23 \$39,048,138, or from an under-recovery of \$24,509,430 to an
24 over-recovery of \$14,653,914.

1 Q. How did Tampa Electric calculate the estimated net true-up
2 to be applied in the January 2026 through December 2026
3 fuel and purchased power cost recovery factors?
4

5 A. The net true-up amount to be recovered in 2026 is the sum
6 of the final true-up amount for the period January 2024
7 through December 2024 and the revised actual/estimated
8 true-up amount for the period January 2025 through December
9 2025. This calculation is shown on Schedule E1-A of Exhibit
10 No. ZDJ-2, Document No. 1.
11

12 Q. What did Tampa Electric calculate as the revised
13 actual/estimated fuel and purchased power cost recovery
14 amount for the period January 2025 through December 2025?
15

16 A. The revised actual/estimated 2025 fuel true-up amount is an
17 under-recovery amount of \$17,562,265 for the period January
18 2025 through December 2025. The detailed calculations
19 supporting the actual/estimated current period true-up are
20 shown in Exhibit No. ZDJ-2, Document No. 1, Schedule E1-B.
21

22 Capacity Cost Recovery Clause

23 Q. What has Tampa Electric calculated as the updated estimated
24 net true-up amount to be applied in the January 2026 through
25 December 2026 capacity cost recovery factors?

1 **A.** The updated estimated net true-up amount applicable for
2 January 2025 through December 2025 is an under-recovery of
3 \$33,825,845 as shown in Exhibit No. ZDJ-2, Document No. 2,
4 page 1 of 4.

5
6 **Q.** How does the revised estimated net true-up amount for 2025
7 compare to the estimated net true-up amount for 2025 filed
8 by the company on July 25, 2025?

9
10 **A.** The net effect of this change is an increase to capacity
11 costs of \$4,137,018, or from an under-recovery of
12 \$29,688,827 to under-recovery of \$33,825,845.

13
14 **Q.** How did Tampa Electric calculate the revised estimated net
15 true-up amount to be applied in the January 2026 through
16 December 2026 capacity cost recovery factors?

17
18 **A.** The revised net true-up amount to be recovered in the 2026
19 capacity cost recovery factors include the final true-up
20 amount for 2024 and the actual/estimated true-up amount for
21 January 2025 and December 2025.

22
23 **Q.** What did Tampa Electric calculate as the final capacity
24 cost recovery true-up amount for 2024?

1 **A.** The final 2024 true-up is an under-recovery of \$8,961,534
2 as shown on Exhibit No. ZDJ-2, Document No. 2, page 1 of 4.

3
4 **Q.** What did Tampa Electric calculate as the revised
5 actual/estimated capacity cost recovery true-up amount for
6 the period January 2025 through December 2025?

7
8 **A.** The revised actual/estimated true-up amount is an under-
9 recovery of \$24,864,312 as shown on Exhibit No. ZDJ-2,
10 Document No. 2, page 1 of 4.

11
12 **Q.** What did Tampa Electric calculate as the revised net
13 capacity cost recovery true-up amount for the period
14 January 2025 through December 2025?

15
16 **A.** The revised net capacity cost recovery true-up amount for
17 the period January 2025 through December 2025 is an under-
18 recovery of \$33,825,845. This calculation is shown on
19 Exhibit No. ZDJ-2, Document No. 2, page 1 of 4.

20
21 **Q.** Does this conclude your direct testimony?

22
23 **A.** Yes, it does.
24
25



BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20250001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2026 THROUGH DECEMBER 2026

TESTIMONY AND EXHIBIT
OF
ZEL D. JONES-PHILLIPS

FILED: SEPTEMBER 4, 2025

TAMPA ELECTRIC COMPANY
DOCKET NO. 20250001-EI
FILED: 09/4/2025

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

ZEL D. JONES-PHILLIPS

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

A. My name is Zel D. Jones-Phillips. My business address is 3600 Midtown Drive, Tampa, Florida 33607. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Manager, Rates in the Regulatory Affairs department.

Q. Have you previously filed testimony in Docket No. 20250001-EI?

A. Yes, I submitted direct testimony on April 2, 2025 and July 25, 2025 under my maiden name. My new legal name is Zel D. Jones-Phillips.

Q. Has your job description, education, or professional experience changed since you last filed testimony in this docket?

1 A. No, they have not.

2

3 Q. What is the purpose of your testimony?

4

5 A. The purpose of my testimony is to present, for Commission
6 review and approval, the proposed annual capacity cost
7 recovery factors, and the proposed annual levelized fuel
8 and purchased power cost recovery factors for January 2026
9 through December 2026. I also describe significant events
10 that affect the factors and provide an overview of the
11 composite effect on the residential bill of changes in
12 the various cost recovery factors for 2026.

13

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

16

17 A. Yes. Exhibit No. ZDJ-3, consisting of four documents, was
18 prepared under my direction and supervision. Document
19 No. 1, consisting of four pages, is furnished as support
20 for the projected capacity cost recovery factors.
21 Document No. 2, which is furnished as support for the
22 proposed levelized fuel and purchased power cost recovery
23 factors, includes Schedules E1 through E10 for January
24 2026 through December 2026 as well as Schedule H1 for
25 2023 through 2026. Document No. 3 provides a comparison

1 of retail residential fuel revenues under the inverted or
2 tiered fuel rate, which demonstrates that the tiered rate
3 is revenue neutral.
4

5 **Q.** Are you requesting Commission approval of the projected
6 fuel and capacity cost recovery factors for the company's
7 various rate schedules?
8

9 **A.** Yes.
10

11 **Q.** How were the fuel and capacity cost recovery clause
12 factors calculated?
13

14 **A.** The fuel and capacity cost recovery factors were
15 calculated as shown on Document Nos. 1 and 2. These
16 factors were calculated based on the current approved rate
17 design, allocation methodology and schedules as approved
18 by the Florida Public Service Commission in Order No.
19 PSC-2025-0038-FOF-EI, issued on February 3, 2025 in
20 Docket No. 20240026-EI.
21

22 **Capacity Cost Recovery**

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

1 **A.** Yes. The capacity cost recovery factors, prepared under
2 my direction and supervision, are provided in Exhibit No.
3 ZDJ-3, Document No. 1, page 3 of 4.

4
5 **Q.** What payments are included in Tampa Electric's capacity
6 cost recovery factors?

7
8 **A.** Tampa Electric is requesting recovery of capacity
9 payments for power purchased for retail customers,
10 excluding optional provision purchases for interruptible
11 customers, through the capacity cost recovery factors. As
12 shown in Exhibit No. ZDJ-3, Document No. 1, page 2 of 4,
13 Tampa Electric is requesting recovery of \$44,827,864
14 after jurisdictional separation, prior year true-up, and
15 application of the revenue tax factor for estimated
16 expenses in 2026.

17
18 **Q.** Please summarize the proposed capacity cost recovery
19 factors by metering voltage level effective beginning in
20 January 2026 for which Tampa Electric is seeking approval.

21
22 **A.**

Rate Class and	Capacity Cost	Recovery Factor
<u>Metering Voltage</u>	<u>Cents per kWh</u>	<u>\$ per kW</u>
RS Secondary	0.264	
GS and CS Secondary	0.221	

1	GSD, SBD Standard	
2	Secondary	0.72
3	Primary	0.71
4	Transmission	0.71
5	GSD Optional	
6	Secondary	0.176
7	Primary	0.174
8	Transmission	0.172
9	GSLDPR/GSLDTPR/SBLDPR/SBLDTPR	0.66
10	GSLDSU/GSLDTSU/SBLDSU/SBLDTSU	0.61
11	LS1/LS2 Secondary	0.032
12		
13	These factors are shown in Exhibit No. ZDJ-3, Document	
14	No. 1, page 3 of 4.	
15		
16	Q.	How does Tampa Electric's proposed average capacity cost
17		recovery factor of 0.216 cents per kWh compare to the
18		factor for January 2025 through December 2025?
19		
20	A.	The proposed capacity cost recovery factor of 0.216 cents
21		per kWh beginning in January 2026 is 0.132 cents per kWh
22		(or \$1.32 per 1,000 kWh) more than the average capacity
23		cost recovery factor of 0.084 cents per kWh for the
24		January 2025 through December 2025 period.
25		

Fuel and Purchased Power Cost Recovery Factor

Q. What is the appropriate amount of the levelized fuel and purchased power cost recovery factor for the period beginning in January 2026?

A. The appropriate amount for the period beginning in January 2026 is 3.516 cents per kWh before the application of the time of use multipliers for on-peak or off-peak usage. Schedule E1-E of Exhibit No. ZDJ-3, Document No. 2, shows the appropriate value for the total fuel and purchased power cost recovery factor for each metering voltage level as projected for the period January 2026 through December 2026.

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

A. The Generating Performance Incentive Factor ("GPIF"), true-up factor, and Asset Optimization Mechanism factor are provided on Schedule E1-C. Tampa Electric has calculated a GPIF reward of \$6,364,097 and an Asset Optimization Mechanism gain of \$3,820,876, which is included in the calculation of the total fuel and purchased power cost recovery factors. In addition, Schedule E1-C indicates the net true-up amount for the

1 January 2025 through December 2025 period is an over-
2 recovery of \$14,653,914.

3
4 **Q.** Please describe the information provided on Schedule
5 E1-D.

6
7 **A.** Schedule E1-D, within Document No. 2, presents Tampa
8 Electric's on-peak and off-peak fuel adjustment factors
9 for January 2026 through December 2026. The schedule also
10 presents Tampa Electric's levelized fuel cost factors at
11 each metering level.

12
13 **Q.** Please describe the information presented on Schedule
14 E1-E.

15
16 **A.** Schedule E1-E presents the standard, tiered, on-peak, and
17 off-peak fuel adjustment factors at each metering voltage
18 to be applied to customer bills.

19
20 **Q.** Please describe the information provided in Document
21 No. 3.

22
23 **A.** Exhibit No. ZDJ-3, Document No. 3 demonstrates that the
24 tiered rate structure is designed to be revenue neutral
25 so that the company will recover the same fuel costs as

it would under the levelized fuel approach.

Q. Please summarize the proposed fuel and purchased power cost recovery factors by metering voltage level for the period beginning in January 2026.

A.	<u>Metering Voltage Level</u>	<u>Fuel Charge Factor</u> <u>(Cents per kWh)</u>
	Secondary	3.516
	Tier I (Up to 1,000 kWh)	3.210
	Tier II (Over 1,000 kWh)	4.210
	Distribution Primary	3.481
	Transmission	3.446
	Lighting Service	3.452
	Distribution Secondary	3.822 (on-peak)
		3.376 (off-peak)
	Distribution Primary	3.784 (on-peak)
		3.342 (off-peak)
	Transmission	3.746 (on-peak)
		3.308 (off-peak)

Q. How does Tampa Electric's proposed levelized fuel adjustment factor of 3.516 cents per kWh compare to the levelized fuel adjustment factor for the June 2025 through December 2025 period?

A. The proposed levelized fuel adjustment factor of 3.516 cents per kWh is 0.125 cents per kWh (or \$1.25 per 1,000 kWh) higher than the levelized fuel adjustment factor of 3.391 cents per kWh for the June 2025 through December 2025 period.

Wholesale Incentive Benchmark and Asset Optimization Mechanism

Q. Will Tampa Electric project a 2026 wholesale incentive benchmark that is derived in accordance with Order No. PSC-2001-2371-FOF-EI issued in Docket No. 20010283-EI?

A. No. Effective January 1, 2018, as authorized by FPSC Order No. PSC-2017-0456-S-EI, issued in Docket No. 20160160-EI on November 27, 2017, the company's Asset Optimization Mechanism replaced the short-term wholesale sales incentive mechanism, and as a result no wholesale incentive benchmark is required for the 2026 projection.

Cost Recovery Factors

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

1 **A.** The composite effect on a residential bill for 1,000 kWh
2 is an increase of \$8.88 in the period beginning January
3 2026 through August 2026, when compared to the June 2025
4 through December 2025 charges. However, for the period of
5 September 2026 through December 2026, the composite
6 effect on a residential bill for 1,000 kWh is a decrease
7 of \$11.58. These amounts are shown in Exhibit No. ZDJ-
8 3, Document No. 2, on Schedule E10.

9
10 **Q.** When should the new rates take effect?

11
12 **A.** The new rates should take effect concurrent with meter
13 readings for the first billing cycle for January 2026.

14
15 **Q.** Does this conclude your direct testimony?

16
17 **A.** Yes.
18
19
20
21
22
23
24
25

1 (Whereupon, prefiled direct testimony of Adam
2 L. Parke was inserted.)

3

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20250001-EI
IN RE: FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

GENERATING PERFORMANCE INCENTIVE FACTOR
TRUE-UP
JANUARY 2024 THROUGH DECEMBER 2024

TESTIMONY AND EXHIBIT
OF
ADAM L. PARKE

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

ADAM L. PARKE

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

A. My name is Adam L. Parke. 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 Supervisor, Mechanical Reliability in the Asset Management department.

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

A. I received a Bachelor of Science degree in Mechanical Engineering from the University of South Florida in 1999 and a Master of Business Administration in 2012 from the University of Tampa. I have accumulated 18 years of experience in the electric utility industry, with experience in the areas of generation planning, plant engineering/maintenance, and plant operations engineer. In my previous role as a Senior Engineer, I was responsible for the balance

1 of plant equipment on the Big Bend Modernization project to
2 convert Big Bend Unit 1 from a coal unit to a combined-cycle
3 unit. In my current role as Supervisor, Mechanical
4 Reliability, I am responsible for supervising the
5 development and implementation of fleet wide maintenance and
6 inspection programs for boilers, high energy piping, and
7 turbines to help ensure equipment operational reliability.
8

9 **Q.** What is the purpose of your testimony?
10

11 **A.** The purpose of my testimony is to present Tampa Electric's
12 actual performance results from unit equivalent availability
13 and heat rate used to determine the Generating Performance
14 Incentive Factor ("GPIF") for the period January 2024 through
15 December 2024. I will also compare these results to the
16 targets established for the period.
17

18 **Q.** Have you prepared an exhibit to support your testimony?
19

20 **A.** Yes, I prepared Exhibit No. ALP-1, consisting of two
21 documents. Document No. 1, entitled "GPIF Schedules" is
22 consistent with the GPIF Implementation Manual approved by
23 the Florida Public Service Commission ("FPSC" or
24 "Commission"). Document No. 2 provides the company's Actual
25 Unit Performance Data for the 2024 period.

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

3
4 **A.** Big Bend Unit 1, Polk Unit 2, and Bayside Units 1 and 2 are
5 included in the calculation of the GPIF.

6
7 **Q.** Have you calculated the results of Tampa Electric's
8 performance under the GPIF during the January 2024 through
9 December 2024 period?

10
11 **A.** Yes, I have. This is shown on Document No. 1, page 4 of 22.
12 Based upon 4.542 Generating Performance Incentive Points
13 ("GPIP"), the result is a reward amount of \$6,364,097 for the
14 period.

15
16 **Q.** Please proceed with your review of the actual results for the
17 January 2024 through December 2024 period.

18
19 **A.** On Document No. 1, page 3 of 22, the actual average common
20 equity for the period is shown on line 14 as \$5,125,691,145.
21 The maximum allowed Jurisdictional Incentive is shown on line
22 21 as \$17,217,870. The incentive cap of 50 percent of the
23 projected fuel savings is \$14,012,453. This produces the
24 maximum penalty or reward amount of \$14,012,453 as shown on
25 line 23.

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

4
5 A. Yes. Operating data for each of the units is filed monthly
6 with the Commission on the Actual Unit Performance Data form.
7 Additionally, outage information is reported to the Commission
8 monthly. A summary of this data for the 12 months provides
9 the basis for the GPIF.

10
11 Q. Are the actual equivalent availability results shown on
12 Document No. 1, page 6 of 22, column 2, directly applicable
13 to the GPIF table?

14
15 A. No. Adjustments to actual equivalent availability may be
16 required as noted in Section 4.3.3 of the GPIF Manual. The
17 actual equivalent availability, including the required
18 adjustment is shown on Document No. 1, page 6 of 22, column
19 4. The necessary adjustments as prescribed in the GPIF Manual
20 are further defined by a letter dated October 23, 1981, from
21 Mr. J. H. Hoffsis of the Commission's Staff. The adjustments
22 for each unit are as follows:

23
24 **Big Bend Unit No. 1**

25 On this unit, 120 planned outage hours were originally

1 scheduled for 2024. Actual outage activities required 534.5
2 equivalent planned outage hours. Consequently, the actual
3 equivalent availability of 89.7 percent is adjusted to 94.3
4 percent, as shown on Document No. 1, page 7 of 22.

5
6 **Polk Unit No. 2**

7 On this unit, 586 planned outage hours were originally
8 scheduled for 2024. Actual outage activities required 548.3
9 equivalent planned outage hours. Consequently, the actual
10 equivalent availability of 90.5 percent is adjusted to 90.3
11 percent, as shown on Document No. 1, page 8 of 22.

12
13 **Bayside Unit No. 1**

14 On this unit, 1,680 planned outage hours were originally
15 scheduled for 2024. Actual outage activities required 388.9
16 equivalent planned outage hours. Consequently, the actual
17 equivalent availability of 93.2 percent is adjusted to 78.9
18 percent, as shown on Document No. 1, page 9 of 22.

19
20 **Bayside Unit No. 2**

21 On this unit, 2,208 planned outage hours were originally
22 scheduled for 2024. Actual outage activities required 2,650.8
23 equivalent planned outage hours. Consequently, the actual
24 equivalent availability of 54.7 percent is adjusted to 58.7
25 percent, as shown on Document No. 1, page 10 of 22.

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

3
4 A. The final adjusted equivalent availabilities for each unit
5 are shown on Document No. 1, page 6 of 22, column 4. This
6 number is incorporated in the respective GPIF table for each
7 unit, shown on pages 17 through 20 of 22. Page 4 of 22
8 summarizes the weighted equivalent availability points to be
9 awarded or penalized.

10
11 Q. Will you please explain the heat rate results relative to the
12 GPIF?

13
14 A. The actual heat rate and adjusted actual heat rate for Tampa
15 Electric's four GPIF units are shown on Document No. 1, page
16 6 of 22. The adjustment was developed based on the guidelines
17 of Section 4.3.16 of the GPIF Manual. This procedure is
18 further defined by a letter dated October 23, 1981, from Mr.
19 J. H. Hoffsis of the FPSC Staff. The final adjusted actual
20 heat rates are also shown on page 5 of 22, column 9. The heat
21 rate value is incorporated in the respective GPIF table for
22 each unit, shown on pages 17 through 20 of 22. Page 4 of 22
23 summarizes the weighted heat rate points to be awarded or
24 penalized.

1 **Q.** What is the overall GPIIP for Tampa Electric for the January
2 2024 through December 2024 period?

3
4 **A.** This is shown on Document No. 1, page 2 of 22. The weighting
5 factors shown on page 4 of 22, column 3, plus the equivalent
6 availability points and the heat rate points shown on page 4
7 of 22, column 4, are substituted within the equation found on
8 page 22 of 22. The resulting value of 4.542 is in the GPIIF
9 table on page 2 of 22, and the reward amount of \$6,364,097 is
10 calculated using linear interpolation.

11
12 **Q.** Are there any other constraints set forth by the Commission
13 regarding the magnitude of incentive dollars?

14
15 **A.** Yes. Incentive dollars are not to exceed 50 percent of fuel
16 savings. Tampa Electric met this constraint, limiting the
17 total potential reward and penalty incentive dollars to
18 \$14,012,453 as shown on Document No. 1, page 3 of 22.

19
20 **Q.** Does this conclude your testimony?

21
22 **A.** Yes.
23
24
25



**BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION**

**DOCKET NO. 20250001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY**

**GENERATING PERFORMANCE INCENTIVE FACTOR
PROJECTIONS
JANUARY 2026 THROUGH DECEMBER 2026**

**TESTIMONY AND EXHIBIT
OF
ADAM L. PARKE**

FILED: SEPTEMBER 4, 2025

TAMPA ELECTRIC COMPANY
DOCKET NO. 20250001-EI
FILED: 09/04/2025

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

ADAM L. PARKE

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

A. My name is Adam L. Parke. My business address is 3600 Midtown Drive, Tampa, Florida 33607. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Supervisor, Mechanical Reliability in the Asset Management department.

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

A. I received a Bachelor of Science degree in Mechanical Engineering from the University of South Florida in 1999 and a Master of Business Administration in 2012 from the University of Tampa. I have accumulated 18 years of experience in the electric utility industry, with experience in the areas of generation planning, plant engineering/ maintenance, and plant operations engineer. In my previous role as a Senior Engineer, I was

1 responsible for the balance of plant equipment on the Big
2 Bend Modernization project to convert Big Bend Unit 1
3 from a coal unit to a combined-cycle unit. In my current
4 role as Supervisor, Mechanical Reliability, I am
5 responsible for supervising the development and
6 implementation of fleet wide maintenance and inspection
7 programs for boilers, high energy piping, and turbines to
8 help ensure equipment operational reliability.

9
10 **Q.** What is the purpose of your testimony?

11
12 **A.** My testimony describes Tampa Electric's methodology for
13 determining the various factors required to compute the
14 Generating Performance Incentive Factor ("GPIF") as
15 ordered by the Commission.

16
17 **Q.** Have you prepared an exhibit to support your direct
18 testimony?

19
20 **A.** Yes. Exhibit No. ALP-2, consisting of two documents, was
21 prepared under my direction and supervision. Document No.
22 1 contains the GPIF schedules. Document No. 2 is a summary
23 of the GPIF targets for the 2026 period.

24
25 **Q.** Which generating units on Tampa Electric's system are

1 included in the determination of the GPIF?

2
3 **A.** Four natural gas combined cycle ("CC") units are included.
4 These are Big Bend Unit 1 CC, Polk Unit 2, and Bayside
5 Units 1 and 2.

6
7 **Q.** Does your exhibit comply with the Commission's approved
8 GPIF methodology?

9
10 **A.** Yes. In accordance with the GPIF Manual, the GPIF units
11 selected represent no less than 80 percent of the
12 estimated system net generation. The units Tampa Electric
13 proposes to use for the period January 2026 through
14 December 2026 represent the top 81 percent of the total
15 forecasted system net generation for this period. It
16 includes generation from the Big Bend Unit 1 CC,
17 commissioned in December 2022. Tampa Electric included
18 Big Bend Unit 1 CC as it is the most efficient unit and
19 makes up 32 percent of our generation.

20
21 To account for the concerns presented in the testimony of
22 Commission Staff witness Sidney W. Matlock during the 2005
23 fuel hearing, Tampa Electric removes outliers from the
24 calculation of the GPIF targets. The methodology was
25 approved by the Commission in Order No. PSC-2006-1057-

1 FOF-EI issued in Docket No. 20060001-EI on December 22,
2 2006.

3
4 **Q.** Did Tampa Electric identify any outages as outliers?

5
6 **A.** Yes, Tampa Electric identified and removed Big Bend Unit
7 1 CC and Bayside Unit 2 outages as outliers based on the
8 outlier criteria established in Order No. PSC-2006-1057-
9 FOF-EI.

10
11 **Q.** Did Tampa Electric make any other adjustments?

12
13 **A.** Yes. As allowed per Section 4.3 of the GPIF Implementation
14 Manual, the company adjusted the Forced Outage and
15 Maintenance Outage Factors to reflect recent unit
16 performance and known unit modifications or equipment
17 changes.

18
19 **Q.** Please describe how Tampa Electric developed the various
20 factors associated with GPIF.

21
22 **A.** The company established targets for equivalent
23 availability and heat rate for each unit considered for
24 the 2026 period. The company determined a range of
25 potential improvements and degradations for each of these

1 metrics.

2
3 **Q.** How were the target values for unit availability
4 determined?

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

12
13 To give an example for the 2026 period, the projected
14 EUOF for Bayside Unit 1 is 1.7 percent, the POF is 28.8
15 percent. Therefore, the target EAF for Bayside Unit 1
16 equals 69.6 percent or:

17
18
$$100\% - (1.7\% + 28.8\%) = 69.6\%$$

19
20 This is shown on Page 4, column 3 of Document No. 1.

21
22 **Q.** How was the potential for unit availability improvement
23 determined?

24
25 **A.** Maximum equivalent availability is derived using the

following formula:

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

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

$$EAF_{MAX} = 1 - [0.80 (1.7\%) + 0.95 (28.8\%)] = 71.3\%$$

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,

1 minimum equivalent availability is calculated using the
 2 following formula:

$$3 \quad \text{EAF}_{\text{MIN}} = 1 - [1.40 (\text{EUOF}_T) + 1.10 (\text{POF}_T)]$$

4
 5 Again, continuing using the Bayside Unit 1 example,

$$6 \quad \text{EAF}_{\text{MIN}} = 1 - [1.40 (1.7\%) + 1.10 (28.8\%)] = 66.0\%$$

7
 8 The equivalent availability maximum and minimum for the
 9 other four units are computed in a similar manner.

10
 11 **Q.** How did Tampa Electric determine the Planned Outage,
 12 Maintenance Outage, and Forced Outage Factors?

13
 14 **A.** The company's planned outages for January 2026 through
 15 December 2026 are shown on page 15 of Document No. 1.
 16 Three GPIF units have a major planned outage of 28 days
 17 or greater in 2026; therefore, three Critical Path Method
 18 Diagrams are provided.

19
 20 The company calculates Planned Outage Factors for each
 21 unit. For example, Bayside Unit 1 is scheduled for a
 22 planned outage more than 28 days from February 1, 2026,
 23 to May 11, 2026. There are 2,520 total planned outage
 24 hours scheduled for the 2026 period out of a total of
 25 8,760 hours during this 12-month period. Consequently,

the POF for Bayside Unit 1 is 28.8 percent or:

$$\frac{2,520}{8,760} \times 100\% = 28.8\%$$

The factor for each unit is shown on pages 5 and 11 through 14 of Document No. 1. Big Bend Unit 1 CC has a POF of 7.9 percent, Polk Unit 2 has a POF of 9.0 percent, Bayside Unit 1 has a POF of 28.8 percent and Bayside Unit 2 has a POF of 3.6 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. The company analyzes historical data and target values to assure applicability to current conditions of operation. This provides assurance that any periods of abnormal operations or recent trends having material effect can be taken into consideration. These target factors are additive and result in a EUOF of 1.7 percent for Bayside Unit 1. The EUOF of Bayside Unit 1 is verified by the data shown on page 13, lines 3, 5, 10, and 11 of Document No. 1 and calculated using the

following formula:

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

Or

$$\text{EUOF} = \frac{(55 + 92)}{8,760} \times 100\% = 1.7\%$$

Relative to Bayside Unit 1, the EUOF of 1.7 percent forms the basis of the equivalent availability target development as shown on pages 4 and 5 of Document No. 1.

Big Bend Unit 1 CC

The projected EUOF for this unit is 3.0 percent. The unit will have one planned outage longer than 28 days in 2026, and the POF is 7.9 percent. Therefore, the target equivalent availability for this unit is 89.0 percent.

Polk Unit 2

The projected EUOF for this unit is 4.2 percent. The unit will have two planned outages in 2026, and the POF is 9.0 percent. Therefore, the target equivalent availability for this unit is 86.7 percent.

Bayside Unit 1

The projected EUOF for this unit is 1.7 percent. The unit will have one planned outage longer than 28 days in 2026, and the POF is 28.8 percent. Therefore, the target equivalent availability for this unit is 69.6 percent.

Bayside Unit 2

The projected EUOF for this unit is 6.3 percent. There are no planned outages longer than 28 days scheduled for 2026, and the POF is 3.6 percent. Therefore, the target equivalent availability for this unit is 90.1 percent.

Q. Please summarize your testimony regarding EAF.

A. The GPIF system weighted EAF of 85.5 percent is shown on page 5 of Document No. 1.

Q. Why are Forced and Maintenance Outage Factors adjusted for planned outage hours?

A. The adjustment makes the factors more accurate and comparable. A unit in a planned outage stage or reserve shutdown stage cannot incur a forced or maintenance outage. To demonstrate the effects of a planned outage, note the Equivalent Unplanned Outage Rate and Equivalent

Unplanned Outage Factor for Bayside Unit 1 on page 13 of Document No. 1. Except for the months of February, March April, May, October 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 planned outages, 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,

$$\text{EFOF} + \text{EMOF} + \text{POF} + \text{EAF} = 100\%$$

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

Q. Has Tampa Electric prepared the necessary heat rate data

1 required for the determination of the GPIF?

2

3 **A.** Yes. Tampa Electric developed target heat rates and ranges
4 of potential operation as required and adjusted them to
5 reflect the aforementioned agreed-upon GPIF methodology.

6

7 **Q.** How did Tampa Electric determine the targets?

8

9 **A.** Net heat rate data for the three most recent July through
10 June annual periods formed the basis for the target
11 development. The company analyzes historical data and the
12 target values to assure applicability to current
13 conditions of operation. This provides assurance that any
14 period of abnormal operations or equipment modifications
15 having material effect on heat rate can be taken into
16 consideration.

17

18 **Q.** How did the company determine the ranges of heat rate
19 improvement and heat rate degradation?

20

21 **A.** The company determined the ranges through analysis of
22 historical net heat rate and net output factor data. This
23 is the same data from which the net heat rate versus net
24 output factor curves have been developed for each unit.
25 This information is shown on pages 24 through 27 of

1 Document No. 1.

2

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

5

6 **A.** The net heat rate versus net output factor curves are the
7 result of a first order curve fit to historical data. The
8 company determined the standard error of the estimate of
9 this data and applied a factor to produce a band of
10 potential improvement and degradation. The computer
11 program for each unit performed both the curve fit and
12 the standard error of the estimate. These curves are also
13 used in post-period adjustments to actual heat rates to
14 account for unanticipated changes in unit dispatch and
15 fuel.

16

17 **Q.** Please summarize your heat rate projection (Btu/Net kWh)
18 and the range about each target to allow for potential
19 improvement or degradation for the 2026 period.

20

21 **A.** The heat rate target for Big Bend Unit 1 CC is 6,403
22 Btu/Net kWh with a range of ± 249 Btu/Net kWh. The heat
23 rate target for Polk Unit 2 is 7,131 Btu/Net kWh with a
24 range of ± 134 Btu/Net kWh. The heat rate for Bayside Unit
25 1 is 7,242 Btu/Net kWh with a range of ± 300 Btu/Net kWh.

1 The heat rate target for Bayside Unit 2 is 7,572 Btu/Net
2 kWh with a range of ± 285 Btu/Net kWh. A zone of tolerance
3 of ± 75 Btu/Net kWh is included within a range for each
4 target. This is shown on pages 7 through 10 of Document
5 No. 1.

6
7 **Q.** Do these heat rate targets and ranges meet the
8 Commission's requirements?

9
10 **A.** Yes.

11
12 **Q.** After determining the target values and ranges for average
13 net operating heat rate and equivalent availability, what
14 is the next step in determining the GPIF targets?

15
16 **A.** The next step is to calculate the savings and weighting
17 factor to be used for both average net operating heat
18 rate and equivalent availability. This is shown in
19 Document No. 1, pages 7 through 10. The company performed
20 the baseline production costing analysis to calculate the
21 total system fuel cost if all units operated at target
22 heat rate and target availability for the period. This
23 total system fuel cost of \$734,055,680 is shown on
24 Document No. 1, page 6, column 2. Tampa Electric performed
25 multiple production cost simulations to calculate total

1 system fuel cost with each unit individually operating at
2 maximum improvement in equivalent availability and each
3 station operating at maximum improvement in average net
4 operating heat rate. The respective savings are shown on
5 page 6, column 4 of Document No. 1.

6
7 Column 4 totals \$24,456,710, which reflects the savings
8 if all of the units operated at maximum improvement. The
9 company then calculates a weighting factor for each metric
10 by dividing unit savings by the total. For Bayside Unit
11 1, the weighting factor for average net operating heat
12 rate is 11.80 percent as shown in the right-hand column
13 on Document No. 1, page 6. Pages 7 through 10 of Document
14 No. 1 show the point table, the Fuel Savings/(Loss) and
15 the equivalent availability or heat rate value. The
16 individual weighting factor is also shown. For example,
17 as shown on page 9 of Document No. 1, if Bayside Unit 1,
18 operates at 6,943, the adjusted actual average heat rate,
19 fuel savings would equal \$2,886,900 and +10 average net
20 operating heat rate points would be awarded.

21
22 The GPIF Reward/Penalty table on page 2 of Document No.
23 1 is a summary of the tables on pages 7 through 10. The
24 left-hand column of this document shows the incentive
25 points for Tampa Electric. The center column shows the

1 total fuel savings and is the same amount as shown on
2 page 6, column 4, or \$24,456,710. The right-hand column
3 of page 2 is the estimated reward or penalty based upon
4 performance.

5
6 **Q.** How did the company determine the maximum allowed
7 incentive?

8
9 **A.** Referring to page 3, line 14, the estimated average common
10 equity for the period January 2026 through December 2026
11 is \$5,762,210,477. This produces the maximum allowed
12 jurisdictional incentive of \$19,356,023 shown on line 21.

13
14 **Q.** Are there any constraints set forth by the Commission
15 regarding the magnitude of incentive dollars?

16
17 **A.** Yes. As Order No. PSC-2013-0665-FOF-EI, issued in Docket
18 No. 20130001-EI on December 18, 2013, states, incentive
19 dollars are not to exceed 50 percent of fuel savings.
20 Page 2 of Document No. 1 demonstrates that this constraint
21 is met, limiting total potential reward and penalty
22 incentive dollars to \$12,228,355.

23
24 **Q.** Please summarize your direct testimony.
25

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).

$$\begin{aligned} \text{GPIP} = & (0.0608 \text{ EAP}_{\text{BBCC1}} + 0.1019 \text{ EAP}_{\text{PK2}} \\ & + 0.1702 \text{ EAP}_{\text{BAY1}} + 0.0857 \text{ EAP}_{\text{BAY2}} \\ & + 0.2810 \text{ HRP}_{\text{BBCC1}} + 0.1127 \text{ HRP}_{\text{PK2}} \\ & + 0.1180 \text{ HRP}_{\text{BAY1}} + 0.0696 \text{ HRP}_{\text{BAY2}}) \end{aligned}$$

Where:

GPIP = Generating Performance Incentive Points

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

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

Q. Have you prepared a document summarizing the GPIF targets for the January 2026 through December 2026 period?

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

1 unit.

2

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

4

5 **A.** Yes, it does.

6

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

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20250001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2026 THROUGH DECEMBER 2026

TESTIMONY
OF
BENJAMIN F. SMITH II

FILED: SEPTEMBER 4, 2025

TAMPA ELECTRIC COMPANY
DOCKET NO. 20250001-EI
FILED: 09/04/2025

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 3600 Midtown Drive, Tampa, Florida 33607. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Gas and Power Origination within the Origination and Trading 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.

1 During my years with the company, I have worked in the
2 areas of transmission engineering, distribution
3 engineering, resource planning, retail marketing, and
4 wholesale power marketing. I am currently the Manager,
5 Gas and Power Origination within the Origination and
6 Trading Department. My responsibilities are to evaluate
7 short-term and long-term power purchase and sale
8 opportunities within the wholesale power market, assist
9 in wholesale power and gas transportation origination and
10 contract structures; assist in solid fuel, liquid fuel,
11 and combustion byproduct contract administration and
12 market opportunities; and manage the company's renewable
13 energy credit (REC) sales activity in the voluntary REC
14 market. In this capacity, I interact with wholesale power
15 market participants such as utilities, municipalities,
16 electric cooperatives, power marketers, other wholesale
17 developers and independent power producers, as well as
18 with natural gas pipeline owners and transporters and REC
19 brokers.

20
21 **Q.** Have you previously testified before the Florida Public
22 Service Commission ("Commission")?

23
24 **A.** Yes. I have submitted written testimony in the annual
25 fuel docket since 2003, and I have testified before this

1 Commission in Docket Nos. 20030001-EI, 20040001-EI, and
2 20080001-EI regarding the appropriateness and prudence of
3 Tampa Electric's wholesale purchases and sales.

4
5 **Q.** What is the purpose of your testimony in this proceeding?

6
7 **A.** The purpose of my testimony is to provide a description
8 of Tampa Electric's purchased power agreements that the
9 company has entered and for which it is seeking cost
10 recovery through the Fuel and Purchased Power Cost
11 Recovery Clause ("fuel clause") and the Capacity Cost
12 Recovery Clause. I also describe Tampa Electric's
13 purchased power strategy for mitigating price and supply-
14 side risk, while providing customers with a reliable
15 supply of economically priced purchased power.

16
17 **Q.** Please describe the efforts Tampa Electric makes to ensure
18 that its wholesale purchases and sales activities are
19 conducted in a reasonable and prudent manner.

20
21 **A.** Tampa Electric evaluates potential purchase and sale
22 opportunities by analyzing the expected available amounts
23 of generation and power required to meet the projected
24 demand and energy of its customers. The company makes
25 purchases to achieve reserve margin requirements, meet

1 customer demand and energy needs, meet operating reserve
2 requirements, supplement generation during unit outages,
3 and for economical purposes. When Tampa Electric
4 considers making a power purchase, the company diligently
5 searches for available supplies of wholesale capacity or
6 energy from creditworthy counterparties. The objective is
7 to secure reliable quantities of purchased power for
8 customers at the best possible price.

9
10 Conversely, when there is a sale opportunity, the company
11 offers profitable wholesale capacity or energy products
12 to creditworthy counterparties. The company has wholesale
13 power purchase and sale transaction enabling agreements
14 with numerous counterparties. This process helps to
15 ensure that the company's wholesale purchase and sale
16 activities are conducted in a reasonable and prudent
17 manner.

18
19 **Q.** Has Tampa Electric reasonably managed its wholesale power
20 purchases and sales for the benefit of its retail
21 customers?

22
23 **A.** Yes, it has. Tampa Electric has fully complied with the
24 Commission's Order No. PSC-1997-0262-FOF-EI, which was
25 approved on March 11, 1997, issued in Docket No. 19970001-

1 EI, and governs the treatment of separated and non-
2 separated wholesale sales. The company's wholesale
3 purchase and sale activities and transactions are also
4 reviewed and audited on a recurring basis by the
5 Commission.

6
7 In addition, Tampa Electric actively manages its
8 wholesale purchases and sales with the goal of
9 capitalizing on opportunities to reduce customer costs
10 and improve reliability. The company monitors its
11 contractual rights with purchased power suppliers, and
12 with entities to which wholesale power is sold, to detect
13 and prevent any breach of the company's contractual
14 rights. Tampa Electric continually strives to improve its
15 knowledge of wholesale power markets and available
16 opportunities within the marketplace. The company uses
17 this knowledge to minimize the costs of purchased power
18 and to maximize the savings the company provides to retail
19 customers by making wholesale sales when excess power is
20 available on Tampa Electric's system and market
21 conditions allow.

22
23 Q. Please describe Tampa Electric's 2025 wholesale power
24 purchases.
25

1 **A.** Tampa Electric assessed the wholesale power market and
2 entered into short- and long-term purchases based on price
3 and availability of supply. Accounting for actuals
4 through July, approximately 9.4 percent of the company's
5 expected needs for 2025 will be met using purchased power.
6 This includes economy energy purchases, reliability
7 purchases, as-available purchases from qualifying
8 facilities, forward purchases from Duke Energy Florida
9 ("DEF"), the Florida Municipal Power Agency ("FMPA"),
10 Florida Power & Light ("FPL"), Macquarie, the Orlando
11 Utilities Commission ("OUC"), Seminole Electric
12 Cooperative ("SEC"), and the company's 18 MW, long-term,
13 firm purchase from Pasco County's waste-to-energy ("WTE")
14 facility approved by the Commission in 2024. A few of the
15 forward purchases applicable to 2025 have come to an end,
16 but all are summarized below.

17
18 Tampa Electric's current contract with DEF is an extension
19 of its previous contract to purchase non-firm energy. The
20 previous contract was set to conclude at the end of
21 November 2024. The parties have extended the contract
22 through several amendments, and the contract now
23 continues through December 2025. The extension has no
24 must-take obligation, providing Tampa Electric with the
25 flexibility to schedule the energy when beneficial to

1 customers. In addition, the extension is for non-firm
2 energy only, no firm capacity. The maximum capacity for
3 this purchase is 515 MW, and for 2025, the purchases
4 associated with this agreement have provided over \$3.8
5 million in savings to customers through the end of June.
6 These savings flow through the company's asset
7 optimization mechanism and benefit customers in
8 accordance with the methodology approved by the
9 Commission in Order No. PSC-2025-0038-FOF-EI-, issued on
10 February 3, 2025, in Docket No. 20240026-EI.

11
12 The following purchases supported the company's plan to
13 lower exposure to natural gas risk during its forecasted
14 winter peak or in the event Tampa Electric experiences
15 unusually cold weather. The company's plan to minimize
16 its natural gas risk is addressed in the direct testimony
17 of witness John Heisey.

- 18 • A 75 MW firm peaking call option from FMPA was executed
19 November 2024 for the period December 2024 through
20 February 2025.
- 21 • A 150 MW firm peaking call option from OUC was executed
22 in December 2024 for the period January through
23 February 2025.
- 24 • A 200 MW firm peaking call option from SEC was executed
25 in November 2024 for the period December 2024 through

February 2025.

- A 300 MW call option from FPL was executed in December 2024 for mid-December 2024 through mid-February 2025. This contract was contingent upon the availability of Manatee Unit 1 and Unit 2 and provided access to volumes of oil-based energy. The exact period of the agreement was December 13, 2024, through February 17, 2025.

Tampa Electric's forward purchases described below are for the summertime loads. These purchases, which are predominantly economic, are as follows:

- A 75 MW, non-firm, must-take energy purchase from Macquarie that was executed May 2025 for the month of June 2025. The total savings to customers are \$29,970, which flows through the company's optimization mechanism and benefit customers as previously noted.
- Various non-firm, must-take energy purchases from FPL executed February and March 2025 for certain months over the period March through October 2025. The purchase amounts are March (250 MW), April (200 MW), May (300 MW), June (350 MW), July (150 MW), and October (150 MW). These purchases are all economic with the exception of the 150 MW in July, which is for reliability. The projected total customer savings for the economic purchases are \$6.6 million, which flow

1 through the company's optimization mechanism and
2 benefit customers as previously noted.

3
4 **Q.** Does Tampa Electric anticipate entering into new
5 wholesale power purchases for 2025 and beyond?

6
7 **A.** Yes. In addition to the previously mentioned 18 MW
8 purchase from Pasco County's WTE facility, which was
9 approved by the Commission in Consummating Order No.
10 PSC-2024-0064-PAA-EI issued March 12, 2024, and began
11 January 2025, Tampa Electric has another long-term
12 purchase that began this year. That contract is for the
13 purchase of 16 MW from the Hillsborough County
14 ("Hillsborough") WTE Facility. The contract has a 10-
15 year term, is a firm must-take, and continues through
16 February 2035. The Hillsborough agreement provides
17 approximately \$3 million in savings to customers on a net
18 present value basis. The Commission approved the contract
19 for full cost recovery in Order No. PSC-2025-0210-PAA-EI,
20 issued June 17, 2025, and finalized in Consummating Order
21 PSC-2025-0263-CO-EI released July 9, 2025, which made the
22 effective start date August 1, 2025. The pricing for
23 this purchase is an all-energy rate in \$/MWh. There is
24 no capacity charge. At present, Tampa Electric has no
25 other forward purchases for 2025 and beyond. However,

1 the company constantly searches for purchase
2 opportunities that benefit customers. As other purchase
3 opportunities materialize, the company evaluates each
4 product to determine the viability of making it part of
5 the supply portfolio Tampa Electric uses to serve
6 customers.

7
8 The company projects approximately 3.2 percent of the
9 company's expected needs for 2026 will be met using
10 purchased power. However, similar to the current year,
11 the company will search for forward purchase
12 opportunities that benefit customers, which could result
13 in capacity costs being incurred. Tampa Electric has
14 included \$11.5 million in its 2026 Capacity Cost Recovery
15 Clause forecast for potential purchased power
16 opportunities.

17
18 **Q.** How does Tampa Electric mitigate the risk of disruptions
19 to its purchased power supplies during major weather-
20 related events, such as hurricanes?

21
22 **A.** During hurricane season, Tampa Electric continues to use
23 a purchased power risk management strategy to minimize
24 potential power supply disruptions. The strategy includes
25 monitoring storm activity, evaluating the impact of

1 storms on existing forward purchases and the rest of the
2 wholesale power market, and communicating with suppliers
3 about their storm preparations and potential impacts to
4 existing transactions. The purchased power risk
5 management strategy also includes purchasing additional
6 power on the forward market, if appropriate, for
7 reliability and economics, evaluating transmission
8 availability and the geographic location of electric
9 resources, reviewing sellers' fuel sources and dual-fuel
10 capabilities, and focusing on fuel-diversified purchases.
11 Absent the threat of a hurricane, and for all other months
12 of the year, the company evaluates economic combinations
13 of short- and long-term purchase opportunities in the
14 marketplace.

15
16 **Q.** Please describe Tampa Electric's wholesale energy sales
17 for 2025 and 2026.

18
19 **A.** Tampa Electric entered into various non-separated (e.g.,
20 next-hour and next-day sales) wholesale sales in 2025,
21 and the company anticipates making additional non-
22 separated sales during the balance of 2025 and 2026. The
23 gains from these sales are shared between Tampa Electric
24 and its customers through the company's asset
25 optimization mechanism.

1 Q. Please summarize your direct testimony.

2
3 A. Tampa Electric constantly monitors and assesses the
4 wholesale power market to identify purchase and sales
5 opportunities that benefit the company's customers. By
6 taking advantage of these opportunities, Tampa Electric
7 reduces costs to and improves service reliability for
8 customers. The company's energy supply strategy includes
9 self-generation and physical short-term (e.g., intra-
10 hour, hourly, next-day, weekly) and longer term (e.g.,
11 monthly, seasonal) power purchases. The company also
12 makes wholesale power sales that benefit customers when
13 excess power is available on Tampa Electric's system and
14 market conditions allow. Tampa Electric's approach to the
15 wholesale power market provides customers with reliable
16 supply at the lowest possible cost.

17
18 Q. Does this conclude your direct testimony?

19
20 A. Yes.



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October 14, 2025

VIA ELECTRONIC FILING

Mr. Adam J. Teitzman
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Fuel and Purchased Power Cost Recovery Clause with Generating
Performance Incentive Factor
FPSC Docket No. 20250001-EI

Dear Mr. Teitzman:

Tampa Electric Company ("Tampa Electric") hereby submits this errata sheet to update the Direct Testimony of Benjamin F. Smith II filed by Tampa Electric in this docket on September, 4 2025. See DN 09106-2025. Tampa Electric is filing this letter and attachments as a courtesy to the Florida Public Service Commission and the parties, and to promote efficiency in this docket.

	Page and Line Reference	Change
Direct Testimony of Benjamin F. Smith II	Page 7, Line 18	Replace "75 MW" with "100 MW"
	Page 8, Line 21	Replace "350 MW" with "375 MW"

Also enclosed for filing as "Attachment 1" to this letter is a strikethrough version of pages 7 and 8 of the Direct Testimony of Benjamin F. Smith II. Enclosed as "Attachment 2" to this letter is a "clean" version pages 7 and 8 of the Direct Testimony of Benjamin F. Smith II.

Thank you for your assistance in connection with this matter.

Sincerely,

A handwritten signature in blue ink that reads "Malcolm N. Means". The signature is written in a cursive style with a large initial 'M'.

Malcolm N. Means

MNM/bml
Attachments

cc: All Parties of Record (w/attachments)

Attachment 1

1 customers. In addition, the extension is for non-firm
2 energy only, no firm capacity. The maximum capacity for
3 this purchase is 515 MW, and for 2025, the purchases
4 associated with this agreement have provided over \$3.8
5 million in savings to customers through the end of June.
6 These savings flow through the company's asset
7 optimization mechanism and benefit customers in
8 accordance with the methodology approved by the
9 Commission in Order No. PSC-2025-0038-FOF-EI-, issued on
10 February 3, 2025, in Docket No. 20240026-EI.

11
12 The following purchases supported the company's plan to
13 lower exposure to natural gas risk during its forecasted
14 winter peak or in the event Tampa Electric experiences
15 unusually cold weather. The company's plan to minimize
16 its natural gas risk is addressed in the direct testimony
17 of witness John Heisey.

- 18 • A ~~10075~~ MW firm peaking call option from FMPA was
19 executed November 2024 for the period December 2024
20 through February 2025.
- 21 • A 150 MW firm peaking call option from OUC was executed
22 in December 2024 for the period January through
23 February 2025.
- 24 • A 200 MW firm peaking call option from SEC was executed
25 in November 2024 for the period December 2024 through

February 2025.

- A 300 MW call option from FPL was executed in December 2024 for mid-December 2024 through mid-February 2025. This contract was contingent upon the availability of Manatee Unit 1 and Unit 2 and provided access to volumes of oil-based energy. The exact period of the agreement was December 13, 2024, through February 17, 2025.

Tampa Electric's forward purchases described below are for the summertime loads. These purchases, which are predominantly economic, are as follows:

- A 75 MW, non-firm, must-take energy purchase from Macquarie that was executed May 2025 for the month of June 2025. The total savings to customers are \$29,970, which flows through the company's optimization mechanism and benefit customers as previously noted.
- Various non-firm, must-take energy purchases from FPL executed February and March 2025 for certain months over the period March through October 2025. The purchase amounts are March (250 MW), April (200 MW), May (300 MW), June (375~~350~~ MW), July (150 MW), and October (150 MW). These purchases are all economic with the exception of the 150 MW in July, which is for reliability. The projected total customer savings for the economic purchases are \$6.6 million, which flow

Attachment 2

1 customers. In addition, the extension is for non-firm
2 energy only, no firm capacity. The maximum capacity for
3 this purchase is 515 MW, and for 2025, the purchases
4 associated with this agreement have provided over \$3.8
5 million in savings to customers through the end of June.
6 These savings flow through the company's asset
7 optimization mechanism and benefit customers in
8 accordance with the methodology approved by the
9 Commission in Order No. PSC-2025-0038-FOF-EI-, issued on
10 February 3, 2025, in Docket No. 20240026-EI.

11
12 The following purchases supported the company's plan to
13 lower exposure to natural gas risk during its forecasted
14 winter peak or in the event Tampa Electric experiences
15 unusually cold weather. The company's plan to minimize
16 its natural gas risk is addressed in the direct testimony
17 of witness John Heisey.

- 18 • A 100 MW firm peaking call option from FMPA was executed
19 November 2024 for the period December 2024 through
20 February 2025.
- 21 • A 150 MW firm peaking call option from OUC was executed
22 in December 2024 for the period January through
23 February 2025.
- 24 • A 200 MW firm peaking call option from SEC was executed
25 in November 2024 for the period December 2024 through

February 2025.

- A 300 MW call option from FPL was executed in December 2024 for mid-December 2024 through mid-February 2025. This contract was contingent upon the availability of Manatee Unit 1 and Unit 2 and provided access to volumes of oil-based energy. The exact period of the agreement was December 13, 2024, through February 17, 2025.

Tampa Electric's forward purchases described below are for the summertime loads. These purchases, which are predominantly economic, are as follows:

- A 75 MW, non-firm, must-take energy purchase from Macquarie that was executed May 2025 for the month of June 2025. The total savings to customers are \$29,970, which flows through the company's optimization mechanism and benefit customers as previously noted.
- Various non-firm, must-take energy purchases from FPL executed February and March 2025 for certain months over the period March through October 2025. The purchase amounts are March (250 MW), April (200 MW), May (300 MW), June (375 MW), July (150 MW), and October (150 MW). These purchases are all economic with the exception of the 150 MW in July, which is for reliability. The projected total customer savings for the economic purchases are \$6.6 million, which flow

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

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20250001-EI
IN RE: FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

2024 ASSET OPTIMIZATION MECHANISM

TESTIMONY AND EXHIBIT

JOHN C. HEISEY

FILED: April 2, 2025

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 30 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

1 capacity in bilateral and organized markets. I joined
2 Tampa Electric in September 2016 as the Manager of Gas
3 and Power Trading. I have held the position of Director,
4 Origination and Trading since August 2021. In this role,
5 I am responsible for directing all activities associated
6 with the procurement and delivery of energy commodities
7 for Tampa Electric's generation fleet. Such activities
8 include the trading, optimization, strategy, planning,
9 origination, compliance and regulatory oversight of
10 natural gas, power, coal, oil, byproducts, and wholesale
11 renewable energy credits (RECs). I am also responsible
12 for all aspects of the Asset Optimization Mechanism.

13
14 **Q.** Please state the purpose of your testimony.

15
16 **A.** The purpose of my testimony is to present, for the
17 Commission's review, the 2024 results of Tampa Electric's
18 activities under the Asset Optimization Mechanism, as
19 originally authorized by FPSC Order No. PSC-2017-0456-S-
20 EI, issued in Docket No. 20160160-EI on November 27, 2017
21 and most recently extended by the Commission in Order No.
22 PSC-2025-0038-FOF-EI, issued February 3, 2025 in Docket
23 No. 20240026-EI.

24
25 **Q.** Do you wish to sponsor an exhibit in support of your

1 testimony?

2
3 **A.** Yes. Exhibit No. JCH-1, entitled Asset Optimization
4 Mechanism Results, was prepared under my direction and
5 supervision. My exhibit shows the gains for each type of
6 activity included in the Asset Optimization Mechanism and
7 the sharing of gains between customers and the company.

8
9 **Q.** Please provide an overview of the Asset Optimization
10 Mechanism.

11
12 **A.** The Asset Optimization Mechanism is designed to create
13 additional value for Tampa Electric's customers while
14 also providing an incentive to the company if certain
15 customer-value thresholds are achieved. The Asset
16 Optimization Mechanism includes gains from wholesale
17 power sales and savings from wholesale power purchases,
18 as well as gains from other forms of asset optimization.

19
20 Under the Asset Optimization Mechanism, gains on eligible
21 activities up to \$4.5 million are retained by customers.
22 Gains between \$4.5 million and \$8 million are split, with
23 60 percent of gains allocated to the company's
24 shareholders and 40 percent allocated to customers. Gains
25 above \$8 million are also split, with 50 percent of gains

1 allocated to shareholders and 50 percent of gains
2 allocated to customers.

3
4 Q. What activities are eligible for inclusion under the
5 current Asset Optimization Mechanism?

6
7 A. Gains on the company's wholesale sales, short-term
8 wholesale purchases, and optimization activities are
9 eligible for the program. Optimization activities
10 include: (1) gas storage utilization; (2) delivered gas
11 sales using existing transport; (3) delivered solid fuel
12 and/or transportation; (4) production area (upstream)
13 sales; and (5) asset management agreement activities.

14
15 **Asset Optimization Mechanism Transactions**

16 Q. Please provide the details of Tampa Electric's short-term
17 wholesale power sales under the Asset Optimization
18 Mechanism for 2024.

19
20 A. Asset Optimization Mechanism gains from wholesale power
21 sales were \$4,641,268 or 40 percent of total optimization
22 gains for 2024. The monthly detail is shown in my exhibit
23 on schedule "Wholesale Power Sales-Table 3."

24
25 Q. Please provide the details of Tampa Electric's short-term

1 wholesale power purchases under the Optimization
2 Mechanism for 2024.

3
4 **A.** Asset Optimization Mechanism gains from wholesale power
5 purchases were \$5,906,317 or 52 percent of total
6 optimization gains for 2024. The monthly detail can be
7 found in my exhibit on schedule "Wholesale Power
8 Purchases-Table 4."

9
10 **Q.** Please describe Tampa Electric's asset optimization
11 activities and the gains from those transactions under
12 the Asset Optimization Mechanism for 2024.

13
14 **A.** Asset Optimization Mechanism gains from asset
15 optimization activities were \$894,167 or 8 percent of
16 total optimization gains for 2024. The gains from asset
17 optimization activities are shown in my exhibit on
18 schedule "Asset Optimization Detail-Table 5."

19
20 A description of Tampa Electric's 2024 asset optimization
21 activities is provided below.

- 22 • Delivered gas sales using existing transport - sell
23 gas to Florida customers, using Tampa Electric's
24 existing gas transportation capacity during periods
25 when it is not needed to serve Tampa Electric's

1 native electric load;

- 2 • Asset Management Agreement ("AMA") - outsource
3 optimization functions to a third party through
4 assignment of power, transportation and/or storage
5 rights in exchange for a premium to be paid to Tampa
6 Electric. Regarding transportation, revenue from the
7 release of natural gas pipeline capacity is not
8 subject to sharing under the Asset Optimization
9 Mechanism consistent with FPSC Order No. PSC-2021-
10 0423-S-EI.

11
12 **Q.** Please summarize the activities and results of the Asset
13 Optimization Mechanism for 2024.

14
15 **A.** Tampa Electric participated in the following Asset
16 Optimization Mechanism activities in 2024: wholesale
17 power purchases and sales, delivered gas sales, and a
18 natural gas storage AMA. The total asset optimization
19 gains for 2024 were \$11,441,752 which exceeded the
20 \$4,500,000 threshold by \$6,941,752 as shown in my exhibit
21 on schedule "Total Gains Threshold Schedule-Table 1."
22 Customer benefits were \$7,620,876 and company benefits
23 were \$3,820,876 in 2024 as shown in my exhibit on schedule
24 "Total Gains Sharing Schedule-Table 2."

1 **Q.** Did Tampa Electric incur incremental Asset Optimization
2 Mechanism costs during 2024?

3
4 **A.** Yes, Tampa Electric incurred incremental Asset
5 Optimization Mechanism personnel costs to manage these
6 activities. However, the company agreed that it would not
7 seek recovery of these costs through the Asset
8 Optimization Mechanism if it were approved and therefore
9 has not separately tracked the costs.

10
11 **Q.** Overall, were Tampa Electric's activities under the Asset
12 Optimization Mechanism successful in 2024?

13
14 **A.** Yes, Tampa Electric produced customer gains of
15 \$7,620,876. The company continues to focus on
16 improvements in processes, reporting, and optimization
17 strategies.

18
19 Temperatures in Tampa were moderate most of the year.
20 Tampa Electric's gains across four optimization products
21 were consistent from month to month. There were two
22 exceptions; 1) a cold weather event in January, which
23 provided some incremental power and gas sales
24 opportunities, and 2) an unusually warm and dry May,
25 allowing us to utilize a favorable economic power purchase

1 for customer savings. There was record precipitation in
2 August through October which minimized optimization gains
3 during that period. Delivered gas sales and natural gas
4 storage AMA gains provided the balance of the gains for
5 2024.

6
7 **Q.** Does this conclude your testimony?

8
9 **A.** Yes, it does.



**BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION**

**DOCKET NO. 20250001-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 2026 THROUGH DECEMBER 2026

**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 30 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

1 Tampa Electric in September 2016 as the Manager of Gas
2 and Power Trading. I have held the position of Director,
3 Origination and Trading since August 2021. In this role,
4 I am responsible for directing all activities associated
5 with the procurement and delivery of energy commodities
6 for Tampa Electric's generation fleet. Such activities
7 include the trading, optimization, strategy, planning,
8 origination, compliance and regulatory oversight of
9 natural gas, power, coal, oil, byproducts, and wholesale
10 renewable energy credits (RECs). I am also responsible
11 for all aspects of the Asset Optimization Mechanism.
12

13 **Q.** What is the purpose of your testimony?
14

15 **A.** The purpose of my testimony is to sponsor and describe
16 Exhibit No. JCH-2, entitled Tampa Electric Company's Fuel
17 Procurement and Wholesale Power Purchases Risk Management
18 Plan 2026.
19

20 **Q.** Was this exhibit prepared by you or under your direction
21 and supervision?
22

23 **A.** Yes, it was.
24

25 **Q.** Please describe your exhibit.

1 **A.** My Exhibit No. JCH-2 provides Tampa Electric's overall
2 plan for mitigating risk in the company's procurement of
3 fuel and purchased power during 2026.
4

5 **Q.** Is hedging activity included in Tampa Electric's Risk
6 Management Plan for 2026?
7

8 **A.** No. Tampa Electric currently has no active natural gas
9 hedges.
10

11 **Q.** Does this conclude your testimony?
12

13 **A.** Yes, it does.
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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20250001-EI
FUEL & PURCHASED POWER COST RECOVERY
AND
CAPACITY COST RECOVERY

PROJECTIONS
JANUARY 2026 THROUGH DECEMBER 2026

TESTIMONY
OF
JOHN C. HEISEY

FILED: SEPTEMBER 4, 2025

TAMPA ELECTRIC COMPANY
DOCKET NO. 20250001-EI
FILED: 09/04/2025

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 3600 Midtown Drive, Tampa, Florida 33607. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Senior Director, Origination and Trading.

Q. Have you previously filed testimony in Docket No. 20250001-EI?

A. Yes, I submitted direct testimony on April 2, 2025, and July 25, 2025.

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

1 position.

2
3 **A.** I am responsible for directing all activities associated
4 with the procurement and delivery of energy commodities
5 for Tampa Electric's generation fleet. Such activities
6 include the trading, optimization, strategy, planning,
7 origination, compliance and regulatory oversight of
8 natural gas, power, coal, oil, byproducts, and wholesale
9 renewable energy credits ("RECs"). I am also responsible
10 for all aspects of the Asset Optimization Mechanism.

11
12 **Q.** What is the purpose of your testimony?

13
14 **A.** The purpose of my testimony is to discuss Tampa Electric's
15 fuel mix, fuel price forecasts, potential impacts to fuel
16 prices, and the company's fuel procurement strategies.

17
18 **Fuel Mix and Procurement Strategies**

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

20
21 **A.** Tampa Electric's generation portfolio includes natural
22 gas, solar, coal, and, as a backup fuel, oil powered
23 units. Big Bend Unit 1 combined cycle operates on natural
24 gas, and Big Bend Unit 4 can operate on coal or natural
25 gas. Currently, the company is operating Big Bend Unit 4

1 on natural gas or coal. Polk Unit 1 simple cycle and Unit
2 2 combined cycle use natural gas as a primary fuel and
3 oil as a secondary fuel; and Bayside Station combined
4 cycle units and the company's collection of peakers (i.e.,
5 aero-derivative combustion turbines) all utilize natural
6 gas. South Tampa Resilience Project MacDill Units 1 and
7 2 operate on natural gas. Since oil serves as a backup
8 fuel, oil consumption is primarily for testing, resulting
9 in it being a negligible percentage of system generation.
10 Based on the 2025 actual-estimate projections, the
11 company expects 2025 total system generation, excluding
12 purchased power, to be 87 percent natural gas, 12 percent
13 solar, and 1 percent coal.

14
15 Likewise, in 2026, natural gas-fired and solar generation
16 are expected to be 83 percent and 15 percent of total
17 generation, respectively, with coal-fired generation
18 making up 2 percent of total generation.

19
20 **Q.** Please describe Tampa Electric's fuel supply procurement
21 strategy.

22
23 **A.** Tampa Electric emphasizes flexibility and options in its
24 fuel procurement strategy for all its fuel needs. The
25 company strives to maintain many creditworthy and viable

1 suppliers. Similarly, the company endeavors to maintain
2 multiple delivery path options. Tampa Electric
3 diversifies the locations from which it sources its fuel
4 supply. Having a greater number of fuel supply and
5 delivery options provides increased reliability and
6 flexibility to pursue lower cost options for Tampa
7 Electric customers.

8 9 **Natural Gas Supply Strategy**

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

13
14 **A.** Tampa Electric uses a portfolio approach to natural gas
15 procurement. This approach consists of a blend of pre-
16 arranged base, intermediate, and swing natural gas supply
17 contracts complemented with shorter term spot and
18 seasonal purchases. The contracts have various time
19 lengths to help secure needed supply at competitive prices
20 while maintaining the flexibility to adapt to any changing
21 fuel needs. Tampa Electric utilizes an online auction
22 process to procure annual and seasonal gas supply
23 requirements for the portfolio. The objective of the
24 auction is to increase competition and lower natural gas
25 expense for the benefit of Tampa Electric customers. Tampa

1 Electric purchases its physical natural gas supply from
2 creditworthy counterparties, enhancing the liquidity and
3 diversification of its natural gas supply portfolio.
4 Tampa Electric targets natural gas supply that is reliable
5 and resistant to the impacts of extreme weather. The
6 natural gas prices are based on monthly and daily price
7 indices, further increasing price diversification.

8
9 Tampa Electric diversifies its pipeline transportation
10 assets, including receipt points. The company also uses
11 pipeline and storage services to enhance access to natural
12 gas supply during hurricanes, extreme weather, or other
13 events that constrain supply. Such actions improve the
14 reliability and cost-effectiveness of the physical
15 delivery of natural gas to the company's power plants.
16 Furthermore, Tampa Electric strives daily to obtain
17 reliable supplies of natural gas at favorable prices to
18 mitigate costs for its customers.

19
20 **Q.** Please describe Tampa Electric's diversified natural gas
21 transportation agreements.

22
23 **A.** Tampa Electric currently receives natural gas directly
24 via the Florida Gas Transmission ("FGT") and Gulfstream
25 Natural Gas System, LLC ("Gulfstream") pipelines. The

1 ability to deliver natural gas from these two pipelines
2 to both Bayside Power Station, which is composed of two
3 large natural gas combined-cycle units and four aero-
4 derivative combustion turbines, and Big Bend Station,
5 which is comprised of one combined cycle unit, one steam
6 generating unit, and one aero-derivative combustion
7 turbine, increases the fuel delivery reliability for
8 these stations. Polk Station receives natural gas from
9 FGT only to support natural gas consumption in Polk Units
10 1 and 2. Although the Gulfstream pipeline does not deliver
11 to Polk Station, the station does have the benefit of on-
12 site secondary fuel.

13
14 **Q.** Are there any significant changes to Tampa Electric's
15 expected natural gas usage?

16
17 **A.** No. Tampa Electric's natural gas usage is expected to
18 decrease by four percent in 2026 when compared to 2025;
19 due to an increase in solar and coal generation.

20
21 **Q.** What actions does Tampa Electric take to enhance the
22 reliability of its natural gas supply?

23
24 **A.** Tampa Electric maintains natural gas storage capacity
25 with Bay Gas Storage near Mobile, Alabama to provide

1 operational flexibility and reliability of natural gas
2 supply. The company reserves 2,000,000 MMBtu of long-term
3 storage capacity at this location. The company used this
4 storage during Storm Uri in February 2021, Storm Elliott
5 in December 2022, and the Gulf Coast blizzard in 2025 to
6 replace interrupted supply and to mitigate costs for our
7 customers.

8
9 In addition to storage, Tampa Electric maintains
10 diversified natural gas supply receipt points in FGT Zones
11 1, 2, and 3. Diverse receipt points reduce the company's
12 vulnerability to hurricane impacts and provide access to
13 potentially lower priced gas supply.

14
15 Tampa Electric also reserves capacity on the Southeast
16 Supply Header ("SESH"), Gulf South pipeline ("Gulf
17 South"), Transco's Mobile Bay Lateral ("Transco"), and
18 Trunkline Gas Company LLC ("Trunkline"). SESH, Gulf
19 South, Transco, and Trunkline are upstream pipelines that
20 connect the receipt points of FGT, Gulfstream, and other
21 Mobile Bay area pipelines with natural gas supply in the
22 mid-continent, northeast, and Permian basin. Mid-
23 continent, northeast, and Permian basin natural gas
24 production, specifically shale production, has grown and
25 continues to increase. Thus, SESH, Gulf South, Transco,

1 and Trunkline capacity give Tampa Electric access to
2 secure, lower priced onshore gas supply for a portion of
3 its portfolio. Tampa Electric continuously evaluates its
4 gas transportation portfolio based on changing market
5 conditions to ensure access to reliable natural gas
6 supply. All receipt points in the portfolio are reviewed
7 annually to ensure access to reliable supply basins.

8
9 **Q.** Has Tampa Electric acquired additional natural gas
10 transportation for 2025 and 2026 due to greater use of
11 natural gas?

12
13 **A.** Yes. Tampa Electric acquired additional mid-term capacity
14 on Gulfstream in late 2024. In addition, the company
15 executed power purchases for December 2024 through
16 February 2025 as a lower cost solution compared to
17 acquiring additional short-term pipeline capacity. These
18 power purchases are mentioned in the Direct Testimony of
19 Benjamin F. Smith, II. Tampa Electric continuously
20 monitors market conditions and opportunities to improve
21 portfolio reliability.

22
23 **Coal Supply Strategy**

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

1 **A.** As with its natural gas strategy, Tampa Electric uses a
2 portfolio approach to coal procurement. Big Bend Unit 4
3 is designed to burn high-sulfur Illinois Basin coal, is
4 fully scrubbed for sulfur dioxide and nitrogen oxides,
5 and has been upgraded to operate on natural gas. The plant
6 has varying operational and environmental restrictions
7 and requires solid fuel with custom quality
8 characteristics such as ash content, fusion temperature,
9 sulfur content, heat content, and chlorine content.

10
11 Coal is not a homogenous product. The fuel's chemistry
12 and contents vary based on many factors, including
13 geography. The variability of the product dictates that
14 Tampa Electric selects its fuel based on multiple
15 parameters. Those parameters include unique coal quality
16 characteristics, price, availability, deliverability, and
17 creditworthiness of the supplier.

18
19 Tampa Electric monitors the market to obtain the most
20 favorable prices from sources that meet the needs of the
21 generation stations. The use of daily and weekly
22 publications, independent research analyses from industry
23 experts, discussions with suppliers, and coal
24 solicitations aid the company in monitoring the coal
25 market. This market intelligence also helps shape the

1 company's coal procurement strategy to reflect short- and
2 long-term market conditions. Tampa Electric's strategy
3 provides a stable supply of reliable fuel sources. In
4 addition, this strategy provides the company with the
5 flexibility to take advantage of favorable spot market
6 opportunities and address operational needs.

7
8 **Q.** Please summarize how Tampa Electric will manage its solid
9 fuel supply contracts through 2026.

10
11 **A.** Tampa Electric will supply Big Bend Station with solid
12 fuel through a combination of existing inventory, short-
13 term contracts, and, as necessary, spot purchases in
14 support of the most economic commitment and dispatch for
15 the generation fleet. Short-term and spot purchases allow
16 the company to adjust supply to reflect changing coal
17 quality and quantity needs, operational changes, and
18 pricing opportunities. Currently, the company is
19 operating Big Bend Unit 4 on either natural gas or coal.

20
21 **Coal Transportation**

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

24
25 **A.** Tampa Electric can receive coal at its Big Bend Station

1 via waterborne or rail delivery. Once delivered to Big
2 Bend Station, solid fuel is consumed onsite. As a result
3 of declining solid fuel burns over the last few years,
4 Tampa Electric now purchases delivered coal, where
5 waterborne coal supply and transportation are arranged by
6 the supplier. Procuring delivered waterborne coal
7 continues to provide customers with competitive coal
8 prices through a simplified process. Commodity and
9 transportation of coal by rail is still being arranged
10 separately, as necessary.

11
12 **Q.** Why does the company maintain multiple coal
13 transportation options in its portfolio?

14
15 **A.** Bimodal solid fuel transportation to Big Bend Station
16 affords the company and its customers various benefits.
17 Those benefits include 1) access to more potential coal
18 suppliers, which results in a more competitively priced,
19 and diverse, delivered coal portfolio; 2) the opportunity
20 to switch to either water or rail in the event of a
21 transportation breakdown or interruption on the other
22 mode; and 3) competition among transporters for future
23 solid fuel transportation contracts. The benefits of
24 bimodal solid fuel transportation were apparent in 2022
25 as coal deliveries by rail were not reliable due to labor

1 shortages in the rail industry.

2

3 **Q.** Will Tampa Electric continue to receive coal deliveries
4 via rail in 2025 and 2026?

5

6 **A.** No. Tampa Electric does not expect to receive coal for
7 use at Big Bend Station through the Big Bend rail facility
8 during 2025 and 2026.

9

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

12

13 **A.** Tampa Electric expects to utilize the majority of its
14 solid fuel supply in 2026 from its existing inventory.
15 Any incremental solid fuel requirements will be procured
16 through short-term waterborne deliveries to the company's
17 unloading facilities at Big Bend Station. These
18 deliveries come via the Mississippi River System. The
19 ultimate supply source is dependent upon quality,
20 operational needs, and lowest overall delivered cost.

21

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

24

25 **A.** Yes. Big Bend Unit 4 is projected to burn coal and gas in

1 2026. Although coal consumption has decreased relative to
2 previous years, the expected coal burn in 2026 will be
3 slightly higher than 2025.
4

5 **Q.** Has Tampa Electric reasonably managed its fuel
6 procurement practices for the benefit of its retail
7 customers?
8

9 **A.** Yes. Tampa Electric diligently manages its mix of long-
10 term, intermediate, and short-term purchases of fuel in
11 a manner designed to reduce overall fuel costs while
12 maintaining electric service reliability. The company's
13 fuel activities and transactions are reviewed and audited
14 on a recurring basis by the Commission. In addition, the
15 company monitors its rights under contracts with fuel
16 suppliers to detect and prevent any breach of those
17 rights. Tampa Electric continually strives to improve its
18 knowledge of fuel markets and take advantage of
19 opportunities to minimize the costs of fuel.
20

21 **Q.** Are there any other pertinent aspects of how Tampa
22 Electric manages its fuel supply portfolio?
23

24 **A.** Yes. Tampa Electric has been operating under an Asset
25 Optimization Mechanism since January 1, 2018. The

Commission extended the Asset Optimization Mechanism in Order No. PSC-2025-0038-FOF-EI, issued February 3, 2025 in Docket No. 20240026-EI. This Asset 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, participation in the Southeast Energy Exchange Market ("SEEM"), resale of unutilized fuel supply, an asset management agreement for natural gas storage, utilization of natural gas storage, and transportation assets.

Projected 2026 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 Global, the Energy Information Administration ("EIA"), and other energy market information sources. Future prices for energy commodities as traded on NYMEX, averaged over five consecutive business days ending August 22, 2025, 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

1 expected transportation costs and location differences.

2
3 Coal commodity and transportation prices are projected
4 using contracted prices and information from industry
5 recognized consultants, published indices, such as
6 Coaldesk, LLC and the EIA. Also, the price projections
7 are specific to the quality and mined location of coal
8 utilized by Tampa Electric's Big Bend Unit 4. Final as-
9 burned prices are derived using expected commodity prices
10 and associated transportation costs.

11
12 **Q.** How do the 2026 projected fuel prices compare to the fuel
13 prices projected for 2025 in the company's fuel and
14 purchased power cost recovery filing filed on September
15 5, 2024?

16
17 **A.** Natural prices are expected to increase in 2026. Even
18 though the outlook has additional production coming
19 online, the expectation is that demand from a new wave of
20 LNG export projects will counter that increase. The 2026
21 projected coal prices are similar to those in 2025.

22
23 The commodity price for natural gas during 2026 is
24 projected to be higher (\$3.82 per MMBtu) than the 2025
25 price (\$3.59 per MMBtu) projected in the company's 2025

1 fuel and purchased power cost recovery fuel filing
2 approved by Order No. PSC-2024-0481-FOF-EI on November
3 22, 2024. The 2026 delivered coal price projection is the
4 same as (\$91.33 per ton) the price projected for 2025
5 (\$91.33 per ton) during preparation of the 2025 fuel
6 clause factors.

7
8 **Q.** Does this conclude your direct testimony?

9
10 **A.** Yes.
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1 (Whereupon, prefiled direct testimony of Ivan
2 K. Urlaub was inserted.)

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1 **BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

2 **SOUTHERN ALLIANCE FOR CLEAN ENERGY**

3 **TESTIMONY OF IVAN K. URLAUB**

4 **DOCKET NO. 20250001-EI**

5 **SEPTEMBER 16, 2025**

6

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

8 A. My name is Ivan K. Urlaub. My business address is 104 Juniper Ct, Carrboro, North Carolina, 27510. I
9 am Principal and founder of Urlaub Strategies LLC, a strategy consulting firm. In a consulting capacity, I
10 currently serve as Director, Energy and Infrastructure for New Energy Economics.

11 **Q. Have you previously testified before this Commission?**

12 A. No.

13 **Q. On whose behalf are you testifying in this docket?**

14 A. New Energy Economics was asked by Southern Alliance for Clean Energy to present testimony in this
15 proceeding. I am testifying on behalf of Southern Alliance for Clean Energy.

16 **Q. Please discuss your relevant experience, professional expertise, and educational background.**

17 A. I founded Urlaub Strategies LLC in 2022, where I collaborate with non-profit and private clients on
18 market research and analysis, resource economics and planning, utility tariff and program design, data
19 centers and other large loads, carbon, and business strategies where they intersect with state, federal,
20 and global energy policy and regulation.

21

22 Recently I have provided written comments and expert testimony in integrated resource planning
23 proceedings involving multiple investor owned utilities in Kansas, Missouri, North Carolina, and Georgia. I
24 have contributed to New Energy Economics publication on economic risks presented by natural gas fuel

use for electric generation and economic solutions to mitigate such risks. Prior to founding Urlaub Strategies LLC, I served in a full-time capacity in various roles including Policy Director and Executive Director for the North Carolina Sustainable Energy Association from 2005-2020.

As an Energy Security Fellow with Securing America's Future Energy in 2021, I focused on the impacts of geopolitics and global energy market dynamics on domestic energy markets, infrastructure, and resource planning.

Prior to 2005, I was a NNEMS Fellow with the U.S. Environmental Protection Agency, an Environmental Scientist with PCCI Inc. where I conducted compliance review of worst-case scenario emergency response plans of U.S. domestic oil pipeline operators and U.S. military installations. Prior to that I worked in various capacities including Junior Water Resource Economist for Development Alternatives Inc. on resolution of water resource conflicts in Jordan, Lebanon, West Bank and Gaza, Egypt, and Morocco including leading and supporting teams and projects focused in financial and tariff solutions in country. I hold a Bachelor of Arts degree from George Washington University in both Political Science and Environmental Studies. I hold both a Master of Public Policy and a Master of Environmental Management degrees from Duke University. I also hold an Energy Resilience Certificate from the George Washington University School of Engineering and Applied Science.

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

A. Yes, I am sponsoring the following exhibits:

- Exhibit IKU-1 – Florida Power & Light Energy by Source from 2025 Ten-Year Site Plan
- Exhibit IKU-2 - Duke Energy Florida Energy by Source from 2025 Ten-Year Site Plan
- Exhibit IKU-3 - Natural Gas Use in South Atlantic Power Sector
- Exhibit IKU-4 - Fuel Cost for Natural Gas Power Plants (Electric Utilities only)

- 1 • Exhibit IKU-5 - Premium Paid by Floridians for Natural Gas
- 2 • Exhibit IKU-6 - Acute Spikes in Natural Gas Prices
- 3 • Exhibit IKU-7 - the Florida gas pipeline network and relevant upstream supply
- 4 • Exhibit IKU-8 - Venture Global Gator Express Flow Plot (Receipt)
- 5 • Exhibit IKU-9 - Midcontinent Express Flows Shift to Support Plaquemines Feedgas
- 6 • Exhibit IKU-10 - Florida Gas Transmission Flow Plot (Receipt)
- 7 • Exhibit IKU-11 - Gulfstream, Sabal Trail, and Destin Flow Plots (Receipts)

8 **Q. What is the purpose of your testimony?**

9 A. This docket is concerned with fuel costs over the period 2024 through 2026, which is a relative
10 snapshot view of costs and potential cost savings, precluding robust identification of fuel risks and risk
11 mitigating solutions that could yield greater annual and multi-year cost avoidance than identified in the
12 current docket, primarily through resource diversification.

13

14 The purpose of my testimony is to show that this docket could identify and realize greater fuel cost
15 savings and avoided future costs to the benefit of ratepayers by a) identifying and quantifying the natural
16 gas fuel price and volatility risks utility ratepayers are increasingly exposed to, b) identifying and
17 quantifying the opportunities for greater cost savings to the benefit of ratepayers if these natural gas fuel
18 price and volatility risks are mitigated, and c) recommendations that could be adopted by the
19 Commission to enable more robust fuel cost savings to be quantified and realized.

20

21 **Q. Are Florida ratepayers uniquely exposed to natural gas price volatility?**

22 A. Yes. As a whole, Florida utilities are more dependent on natural gas for generation than ratepayers in
23 other southeast states, Florida's pipeline delivery premiums above Henry Hub pricing are higher, and
24 Florida is served by some of the same pipelines that will face growing competition from international
25 natural gas export markets.

1 Q. Would Florida ratepayers benefit from improved long-term fuel cost management?

2 A. Yes, the evidence in this docket shows that fuel costs are a significant and volatile share of ratepayer
3 bills. But a one-year lookback or projection is inadequate for strategically reducing exposure to fuel costs.

4

5 Q. Does the 10-Year Site Plan process provide an adequate process to develop sound long-term fuel
6 cost management policies?

7 A. As currently provided, no. The Commission accepts filed plans, but there is no resource planning
8 docket in which evidence and expert testimony can be used to develop sound policies that apply to all
9 jurisdictional electric utilities.

10

11 Q. Is the fuel docket the right place to address this issue?

12 A. On a going-forward basis, with adequate notice, yes. Florida is not merely unique in the southeast in
13 its exposure to fuel cost volatility: it is also unique in that the Commission holds a single fuel cost docket
14 providing an opportunity for evidence-based policy development applicable to all jurisdictional electric
15 utilities. Indeed, the concept of just and reasonable rates would appear to include thoughtful
16 development by the Commission of fuel cost management policy to implement in the fuel cost docket.
17 Extending the “look forward” in the fuel docket to match the 10-year site plan would be an
18 administratively efficient way to use an already-existing docket to incrementally develop evidence-based,
19 improved fuel management policies.

20

21 Current natural gas fuel risks ratepayers are exposed to

22 Q. What is the anticipated energy generation portfolio in the Ten-Year Site Plans of FP&L and DEF?

A. Per the Florida PSC’s requirements, both Florida Power & Light (FPL) and Duke Energy Florida (DEF or Duke) have produced Ten-Year Site Plans in 2025.¹

According to FPL’s 2025 Ten-Year Site Plan, FPL plans to add 17,433 MW of solar generation to “generate reliable energy using no fuel, which mitigates the commodity price risk to customers, enhances fuel diversity and helps secure Florida’s energy independence.” Significant storage additions are planned to store solar generation for dispatch as “a key resource that improves system reliability and resource adequacy by addressing the evening peak cost-effectively.”²

FPL notes it already has 469 MW of large-scale, grid-connected battery storage installed on its system, including 460 MW across three installations that are charged by solar facilities. FPL plans include more than doubling this storage output in 2025 with an additional 521.5 MW, before adding a further 3,431 MW of storage from 2026 through 2029. In total, FPL aims to add 7,603 MW nameplate battery storage by 2034 for a total installed capacity of 8,072 MW.

Lastly, FPL is planning to add 475 MW of combustion turbine gas capacity in 2032 to address longer term load growth. Exhibit IKU-1 – Florida Power & Light Energy by Source from 2025 Ten-Year Site Plan shows an increase in combined nuclear and solar generation from 28% in 2023 to a projected 53% by 2034, and a commensurate reduction in natural gas generation.³

Over the next three years DEF is planning to add 900 MW of DEF-owned solar, the first 300 MW of which was recently approved by the Commission, and a total of 4,400 MW over the ten-year planning horizon,

¹ Florida Public Service Commission. Electric Utility Ten-Year Site Plan: Information and Data Requirements. Form PSC/ENG 043-E (11/97).

² Florida Power & Light. 2025 Ten-Year Site Plan. At page 5.

³ Florida Power & Light. 2025 Ten-Year Site Plan. At page 6.

1 including approximately 1,038 MW that will be paired with storage.⁴ Battery Energy Storage plans include
 2 six small projects ranging between 2.4 MW and 17.2 MW of maximum power output.

3
 4 Duke notes in discussion of its projected energy sources that “although DEF’s fuel mix continues to rely
 5 on an increasing amount of natural gas to meet its generation needs, DEF continues to maintain alternate
 6 fuel supplies including long term operation of some coal fired facilities, adequate supplies of oil for dual
 7 fuel back up and increasing amounts of renewable generation particularly from solar generation.”⁵

8
 9 While DEF’s plan is to moderately increase solar energy generation and add a small amount of battery
 10 storage over the next 3 to 5 years, Exhibit IKU-2 – Duke Energy Florida Energy by Source from 2025 Ten-
 11 Year Site Plan shows that DEF’s plan is to reduce natural gas generation from its currently very high 80%
 12 of total energy generation down to 70% by 2034. Continuing this concentrated dependence on natural
 13 gas exposes DEF customers to intensifying natural gas fuel price and supply risks. There are risks that are
 14 not clearly discernable when reviewing a forecast limited to only the next year.

15
 16 **Q. How does the energy mix and related fuel use differ between FPL and DEF’s Ten-Year Site Plans?**

17 A. FPL is proactively managing the fuel costs that are the subject of this docket by adding resources that
 18 drive dependence on gas below fifty percent.⁶ As FPL notes in its Ten-Year Site Plan “New cost-effective
 19 solar will also provide fuel diversity and energy independence by reducing the amount of natural gas FPL
 20 will use to generate electricity compared to the present day and adding battery storage will provide cost-
 21 effective capacity to help maintain system reliability. This diversity will also help to act as a hedge against
 22 swings in natural gas price volatility, providing additional savings to FPL customers during these periods.”⁷

⁴ Duke Energy Florida, LLC. 2025 Ten-Year Site Plan. At pages 3-59 to 3-66.

⁵ Duke Energy Florida, LLC. 2025 Ten-Year Site Plan. At pages 2-27 to 2-30.

⁶ Florida Power & Light. 2025 Ten-Year Site Plan. At page 12

⁷ Florida Power & Light. 2025 Ten-Year Site Plan. At page 6.

1 By contrast DEF's planned addition of 200 MW natural gas combined cycle capacity in 2025 and 940 MW
2 of natural gas peaking capacity by 2034 maintains a high ratepayer exposure to gas price volatility far into
3 the future.⁸

4
5 **Q. Are there methodological and policy differences that underpin these contrasting fuel cost**
6 **management strategies?**

7 A. Yes. FPL assesses reliability using a stochastic loss of load probability (LOLP) analysis.⁹ This approach
8 helps FPL map out a plan to meet systemwide reliability requirements while strategically reducing
9 volatile fuel costs.

10
11 DEF, however, relies on an Effective Load Carrying Capability Study (ELCC) that isolates the reliability
12 contribution of certain resources. Under DEF's analysis, the firm reliability contribution of solar to its
13 system diminishes as its modest solar capacity additions are made.¹⁰

14
15 These seemingly unrelated methodological differences will likely lead to materially different ratepayer
16 outcomes in the annual fuel dockets, as I explore further in my testimony below.

17
18 **Q. You said there were methodological and policy differences, but you only mentioned the**
19 **methodological differences.**

20 A. Yes. It appears to me that, as a matter of policy, ratepayers would benefit from requiring utility
21 companies to manage fuel cost risk more like what FPL is doing, but in this regard, the Commission has
22 not fully developed an approach that applies to all regulated electric utilities. The lack of a policy on this

⁸ Duke Energy Florida, LLC. 2025 Ten-Year Site Plan. At pages 3-2.

⁹ Duke Energy Florida, LLC. 2025 Ten-Year Site Plan. At pages 3-2.

¹⁰ Duke Energy Florida, LLC. 2025 Ten-Year Site Plan. At pages 3-2.

1 issue is essentially leading to differing levels of fuel cost management for ratepayers in different service
2 territories.

3

4 **Q. What is the current state of natural gas fuel use for power generation in Florida and the Southeast?**

5 A. Natural gas use for power generation has grown rapidly across the Southeast since the early 2000s,

6 driven by the retirement of coal plants and a reduction in overall gas prices following the introduction of

7 fracking. Consumption follows a seasonal pattern, with demand peaking during the summer months.

8 Within the region, Florida consistently stands out: in most years over the past two decades, its natural gas

9 use has exceeded that of Georgia, North Carolina, South Carolina, and Virginia combined, as shown in

10 Exhibit IKU-3 - Natural Gas Use in South Atlantic Power Sector. While other states have seen steady

11 growth, their consumption remains modest compared to Florida's, underscoring the state's outsized

12 dependence on natural gas for electricity generation.

13

14 **Q. How much are Floridians paying for natural gas power generation compared to the Southeast**
15 **regional average?**

16 A. Exhibit IKU-4 - Fuel Cost for Natural Gas Power Plants (Electric Utilities only) compares the cost of

17 natural gas delivered to electric utility power plants in Florida and the broader Southeast with the

18 national benchmark price at Henry Hub from 2019 through 2025.¹¹ It shows that the Henry Hub spot

19 price (green dashed line) is consistently the lowest series, while both Florida and the Southeast average

20 sit above it, reflecting transportation charges, regional basis differences, and delivery constraints. The

21 graph is based solely on electric utility data and does not include independent power producers, due to

22 limited availability of consistent reporting.

¹¹ Form EIA-857: Monthly Report of Natural Gas Purchases and Deliveries to Consumers. EIA, July 2025, [Online](#) September 8, 2025.

Florida's delivered costs are often higher than the Southeast average, especially during periods of market stress such as 2021 through 2023. The most dramatic divergence occurred in 2022, when Florida's delivered gas price exceeded \$12/MMBtu, compared with about \$8/MMBtu at Henry Hub. Even as national prices eased beginning in 2023, Florida's costs remained more volatile, while the Southeast average showed somewhat lower and steadier levels.

These results highlight how Florida's heavy reliance on natural gas for power generation makes it more directly exposed to higher and more volatile delivered fuel costs. The persistent gap between Henry Hub and delivered prices underscores Florida's structural disadvantage: its geographic location and dependence on pipelines increase the cost of serving its market with natural gas. When fuel costs surge, as they did in 2021–2022, these added costs flow directly onto customer bills, amplifying the financial burden on Florida consumers compared to the regional average.

Exhibit IKU-5 - Premium Paid by Floridians for Natural Gas shows that both Florida and the Southeast have consistently paid premiums above Henry Hub prices, often ranging from 20% to 60%, with several periods of extreme spikes.¹² Florida's premiums generally move in line with the Southeast average, but they more often sit at the higher end of the range, potentially underscoring the state's exposure to pipeline constraints and local energy market conditions. The most dramatic surges occurred between 2021 and 2023, when premiums exceeded 100%, meaning Florida power plants were paying more than double the Henry Hub benchmark. This volatility illustrates the risks of Florida's heavy reliance on natural gas: consumers are particularly vulnerable when national natural gas prices rise or when delivery bottlenecks amplify regional costs. By contrast, while other Southeast states also face premiums, their more balanced generation mix lessens their overall exposure to these high and unpredictable fuel costs.

¹² Form EIA-923 Power Plant Operations Report. EIA, June 2025, [Online](#) September 8, 2025; and Henry Hub Natural Gas Spot Price. EIA & Thomson Reuters, [Online](#) September 8, 2025.

1 **Q. How is the risk of natural gas price volatility changing?**

2 A. Florida's heavy reliance on natural gas leaves the State especially vulnerable to price volatility and
 3 supply disruptions. For consumers, the fuel cost risks are amplified during price spikes. Exhibit IKU-6 -
 4 Acute Spikes in Natural Gas Prices tracks the frequency of acute price spikes in the Henry Hub natural gas
 5 market, defined as trading days where prices increased by more than 10% compared to the previous
 6 day.¹³

7

8 From 2003 through the mid-2010s, such spikes were relatively rare, averaging only a handful of days per
 9 year. Beginning around 2019, however, the number of spikes rose sharply, and by 2022–2024 exceeded
 10 15 to 25 trading days annually. The chart distinguishes between all months and the summer season,
 11 showing that while volatility is most visible during periods of high demand, it is now a year-round
 12 phenomenon. This sharp increase in volatility shows how significantly natural gas markets have grown
 13 more volatile in recent years. For Florida, where natural gas dominates electricity generation, each price
 14 spike translates into heightened cost uncertainty and increased risk for consumers. By contrast, regions or
 15 portfolios with a more diversified resource mix are less exposed to sudden daily swings in fuel costs.

16

17 The graph (Exhibit IKU-6) therefore highlights the danger of over-reliance on natural gas. Florida's
 18 dependence leaves customers particularly vulnerable to unpredictable fuel price shocks, while a
 19 diversified portfolio—including renewables, storage, and demand-side management—would help buffer
 20 customers from volatility and deliver greater long-term price stability.

¹³ Henry Hub Natural Gas Spot Price. EIA & Thomson Reuters, [Online](#) September 8, 2025.

1 **Q. Are there any other recent dynamics in the economics of natural gas for power generation that**
 2 **further increase overall cost risk for ratepayers?**

3 A. Yes, there are two additional dynamics, including 1) rising regional natural gas demand for power
 4 generation, and 2) increased competition between Florida power plants and LNG export facilities for
 5 upstream gas supply that has historically served Florida's electricity sector.

6

7 **Rising regional natural gas demand for power generation**

8 Rising regional demand for natural gas power generation capacity and fuel may add upward price
 9 pressure on downstream gas deliveries statewide. While the U.S. achieved record domestic natural gas
 10 production in 2024, electric power generation accounted for about 40% of domestic gas consumption¹⁴
 11 and the Southeast power sector's demand for natural gas is expected to continue to rise. For the period
 12 2025 through 2030, the Southeast region has over 10,000 MW of planned natural gas power plant
 13 capacity additions in some stage of planning, approval, or partially complete construction.¹⁵ Even if only a
 14 portion of those planned new natural gas power plants come online, supply of gas in the region will
 15 tighten. Florida is dependent on upstream gas supply from other states that also supply the Southeast
 16 region.

¹⁴ U.S. Energy Information Administration. Short-Term Energy Outlook: Natural Gas. September 9, 2025. [Online](#) on September 15, 2025.

¹⁵ U.S. Energy Information Administration. Preliminary Monthly Electric Generator Inventory. July 2025 Report. August 25, 2025. [Online](#) on September 15, 2025.

1 **Increased competition between Florida power plants and LNG export facility for Florida’s upstream gas**
 2 **supply**

3 Additional upward price pressure is possible as the U.S. is already the largest global LNG exporter and is
 4 working to increase total LNG export capacity about 53% from 2024 through 2026, primarily along the
 5 Gulf Coast.¹⁶

6

7 As shown on the map in Exhibit IKU-7 - the Florida gas pipeline network and relevant upstream supply,
 8 Florida is partially dependent upon gas flow from the Midcontinent Express pipeline (MEP) shown as blue
 9 to the Southeast Supply Header (SESH) shown as purple for delivery to the Florida Gas Transmission (FGT)
 10 shown as pink.¹⁷ Florida additionally sources natural gas from pipelines including Transco, Gulf South, and
 11 Columbia Gulf (not depicted on the map).

12

13 On December 24, 2024, the Plaquemines LNG facility located in Louisiana shipped its first cargo and it
 14 recently reached its full LNG nominal production capacity. As shown in Exhibit IKU-8 - Venture Global
 15 Gator Express Flow Plot (Receipt),¹⁸ the new Plaquemines LNG facility is now pulling 2.5 Bcf/d of feedgas.
 16 Feedgas is delivered through Venture Global’s Gator Express lateral, sourced from the Tennessee Gas
 17 Pipeline (TGP), Texas Eastern Transmission (TETCO), and Columbia Gulf.

18

19 As Plaquemines LNG began pulling more gas from upstream systems including Midcontinent Express
 20 Pipeline (MEP), it created overlap with existing natural gas pipeline demand. Exhibit IKU-9 - Midcontinent

¹⁶ U.S. Energy Information Administration. The United States remains the world’s largest liquefied natural gas exporter in 2024. March 27, 2025. [Online](#) on September 15, 2025.

¹⁷ East Daley Natural Gas Market Data. Showing Florida and the State’s upstream natural gas pipeline system network. Online on September 15, 2025.

¹⁸ East Daley. Plaquemines Insights: July 17, 2025. Posted by Kritika Gaikwad; U.S. Energy Information Administration. The eighth U.S. liquefied natural gas export terminal, Plaquemines LNG, ships first cargo. January 13, 2025. [Online](#) on September 15, 2025.

Express Flows Shift to Support Plaquemines Feedgas shows MEP started shifting gas deliveries to TGP while deliveries to Transco declined.¹⁹

Florida has seasonal gas demand driven by use in natural gas power plants to serve summer cooling loads. With MEP, TGP, and Columbia South capacity now redirecting gas volumes to rising LNG feedgas while MEP's pipeline capacity remains fixed, Florida's gas system has less flexibility to meet Florida's needs during peak periods. Exhibit IKU-10 - Florida Gas Transmission Flow Plot (Receipt) shows that gas receipts are highest during the summer peak demand months, significantly sourced by Transco.²⁰

Assuming electricity demand growth will occur, this overlapping natural gas pipeline demand means DEF and FPL gas plants are increasingly competing with LNG exports for upstream natural gas supply. This competition is likely to lead to increased prices and volatility for Florida gas power plants. Exhibit IKU-11 - Gulfstream, Sabal Trail, and Destin Flow Plots (Receipts) shows that the other three lines that deliver gas to DEF and FP&L for power generation depend on upstream supply from SESH, Transco, and MEP, respectively.²¹

Cost saving opportunities if natural gas fuel risks are mitigated

Q. How are these risks impacting Florida utilities and their ratepaying customers?

A. The above findings are reinforced by filings by FPL and DEF in this docket. The Mohamed testimony for FPL that shows on page 6 that in 2024 FPL's final gas consumption (742,392,223 MMBtu) was 6% higher than estimated (703,079,884 MMBtu), so that even though the final unit cost (\$3.8937/MMBtu) was 5% lower than FPL's estimated unit cost (\$4.1178/MMBtu), the variance between FPL's estimated and final

¹⁹ East Daley. Plaquemines Insights: July 17, 2025. Posted by Kritika Gaikwad.

²⁰ East Daley. Plaquemines Insights: July 17, 2025. Posted by Kritika Gaikwad.

²¹ East Daley. Plaquemines Insights: July 17, 2025. Posted by Kritika Gaikwad.

total cost for gas was less than 1% (estimated was \$2.895 billion, actual was \$2.891 billion).²² That means that FPL's increased use of gas offset the benefits to customers of lower than expected gas prices. It stands to reason that if FPL increases its use of solar and storage, it can decrease its overall use of gas generation to the benefit of customers.

The Dean testimony for DEF shows a variance of 56,958,753 MWh for gas, meaning Duke increased its use of gas for generation, which blunts the savings for customers seen in a lower than estimated price for gas: Dean calculated total gas cost would have been \$106,308,685 lower than estimated if Duke had used the same amount of gas generation it estimated; instead customers only saw a total reduction in gas fuel cost of \$40,349,622.²³

Q. What potential streams of cost savings or avoidance could DEF and FPL pursue?

A. A more balanced resource mix—including renewable energy and other alternatives—would help shield customers from the financial impacts of natural gas price fluctuations. Both the premium being paid by Floridians for natural gas and the frequency and size of natural gas price spikes are likely to increase in the mid-term.

Resource diversification

FPL has analyzed and evidenced that it can maintain reliability while significantly diversifying its resource mix with solar and battery energy storage capacity additions in both the three year period covered by this docket and the ten-year site plan horizon. The Commission's approval of DEF's first phase SoBRA

²² Testimony of Amin Mohamed filed by Florida Power & Light Company in Docket No. 2025001-EI on April 2, 2025.

²³ Testimony of Gary Dean with exhibits filed by Duke Energy Florida in Docket No. 20250001-EI on April 2, 2025.

1 application that is part of DEF's three-year solar expansion specifically states Duke's small but important
2 resource diversification will also result in fuel savings.²⁴

4 **Capacity release**

5 If DEF or FPL do not use or need all the Firm Transportation (FT) the utilities contracted for, the
6 companies can get money back for the FT on capacity release. DEF and FPL have long-term firm
7 transportation contracts on multiple interstate pipeline projects, and the monthly fixed cost of these
8 contracts can be partially recovered through the capacity release market if the need for gas for electricity
9 generation drops as the utilities diversify their portfolios. Currently, the firm transportation costs are
10 passed on to ratepayers.

12 **Q. What is your position on Issue 8 regarding the appropriate projected total fuel and purchased power
13 cost recovery amounts for the one year period of 2026?**

14 A. I recommend approval of projected total fuel cost recovery amounts for the one year period of 2026
15 contingent on the following requirements: that DEF develop and submit in this docket a fuel
16 diversification plan and that FPL affirm to continue its current fuel diversification strategy.

18 **Recommendations to Commission for enabling greater natural gas cost savings**

19 **Q. What do you recommend the Commission do to improve natural gas fuel cost savings and identify
20 and realize any other natural gas-related savings to the benefit of Florida electric ratepayers?**

21 A. The following recommendations would provide the Commission with a comprehensive, more wholly
22 accurate and still current view of natural gas fuel and capital costs associated with maintaining reliable
23 but more affordable electric service. These recommendations, if adopted, are likely to lead utilities and

²⁴ Florida Public Service Commission. News Release: Florida PSC Approves First Phase of Duke's Solar Expansion. [Online](#) on Sep 6, 2025.

the Commission to identify and then realize greater cost savings and other avoided costs to the benefit of Florida's ratepaying customers.

1. Continue this docket with a scope that is of valuable use to developing a cost-effective 10-year site plan

Issue 31 asks 'should this docket be closed?' My recommendation is no. Instead, the Commission should change the scope and requirements of the processes involved in this docket to still attain current purposes, but improve visibility to additional potential multi-year cost savings and better ensure accurate fuel price forecast assumptions. When there were only a few supply side resource options in the late 1990's to early 2000's and before LNG export became the second largest use of domestic natural gas consumption,²⁵ it made sense to look one year back and one year forward to ensure proper and accurate accounting and cost recovery. For this docket to be relevant going forward, more complete and robust analysis of actual and potential avoided costs can be done by expanding the time horizon both further back – possibly five years – and look forward ten years.

2. Expand TYSP requirements to include the expanded information from this docket

Again, this docket would be of significantly greater use and value in identifying potential cost savings and then developing site plans to realize those costs savings on a cyclical basis if this docket presented and vetted the utilities' multi-year fuel cost planning inputs to then be updated and used by utilities in development of the ten-year site plans. Require using updated natural gas fuel price forecasting methodology that incorporates additional natural gas fuel price risks, including but likely not limited to:

²⁵ U.S. Energy Information Administration. The United States remains the world's largest liquefied natural gas exporter in 2024. March 27, 2025. [Online](#) on September 15, 2025.

- 1 • The impact of increasing domestic demand for natural gas for electric power generation across
- 2 the Southeast region on natural gas fuel price, fuel supply, and natural gas capital costs;
- 3 • Increasing fuel price volatility related to acute weather and sometimes chronic geopolitical and
- 4 international trade dynamics that can result in the pass through of additional hundreds of
- 5 millions or billions in unplanned fuel costs to ratepayers;
- 6 • Utility fuel procurement competition with expanding LNG exports utilizing the same pipeline
- 7 systems.

8

9 **Q. Is there anything else you would like to say in conclusion of your testimony?**

10 A. Including the information described above in both an expanded scope of this proceeding going forward

11 and incorporation of same information into the utility TYSP information and data requirements going

12 forward should improve the accuracy and completeness of cost inputs that incorporate fuel supply and

13 cost risks, quantification of those risks, and if they remain high or intensify further, produce additional

14 resource diversification results in TYSP's that will protect ratepayers from those fuel cost risks by

15 mitigating them at the planning stage before multi-year capital and fuel cost commitments are made that

16 must then be recovered from ratepayers.

17

18 Specifically, future inputs and outcomes of this docket and the utilities' ten-year site plans should have

19 more robust risk mitigation and cost avoidance while maintaining reliability as fuel and resource

20 diversification including hybrid resources is able to increasingly avoid higher fuel and capital costs,

21 reducing utility and thereby ratepayer risk of paying for continued high or intensifying fuel price and

22 supply volatility. The end product should be a more economic and efficient process resulting in a more

23 resilient system that better insulates Florida ratepayers from the risks currently faced from the currently

24 high and increasingly inflexible reliance on domestically produced natural gas for power generation.

- 1 **Q. Does this conclude your testimony?**
- 2 **A. Yes.**

1 CHAIRMAN LA ROSA: Let's move, then, to
2 exhibits maybe.

3 MR. SANDY: As for exhibits, staff has crafted
4 a stipulated Comprehensive Exhibit List, which
5 includes all the prefiled exhibits attached to the
6 witnesses' testimony in this case, and a number of
7 staff exhibits. The list has been provided to all
8 the parties and Commissioners and staff and the
9 court reporter.

10 The list is marked as the first hearing
11 exhibit on the Comprehensive Exhibit List, and all
12 the other exhibits should be marked as set forth in
13 the Comprehensive Exhibit List.

14 CHAIRMAN LA ROSA: All right. Well, then, the
15 exhibits are so marked.

16 (Whereupon, Exhibit Nos. 1-31 & 43-76 were
17 marked for identification.)

18 MR. SANDY: We would request that the
19 Comprehensive Exhibit List, or CEL, marked as
20 Exhibit No. 1, and entered into the record.

21 CHAIRMAN LA ROSA: Exhibit 1 is entered.

22 (Whereupon, Exhibit No. 1 was received into
23 evidence.)

24 MR. SANDY: And we would ask that the
25 remaining exhibits, which would be Exhibits 2

1 through 76, as set forth on the CEL, are also
2 entered into the record at this time, Mr. Chair.

3 CHAIRMAN LA ROSA: Parties have had an
4 opportunity to review that? Any concerns?

5 Seeing no objections, 2 through 76 is entered.

6 (Whereupon, Exhibit Nos. 2-31 & 43-76 were
7 marked for identification.)

8 MR. SANDY: We have some issue stipulations
9 that we can address now. These are Type 2 issue
10 stipulations. There are no objections to any of
11 the issue stipulations, as I said a moment ago, as
12 set forth in the Prehearing Order, therefore, you
13 may decide on those issue stipulations at this
14 time.

15 CHAIRMAN LA ROSA: Okay. Commissioners, are
16 there questions?

17 Seeing none, open for a motion.

18 COMMISSIONER PASSIDOMO SMITH: Mr. Chair, I
19 move approval of the proposed Type 2 stipulations
20 as shown on pages 19 through 39 of the Prehearing
21 Order.

22 COMMISSIONER GRAHAM: Second.

23 CHAIRMAN LA ROSA: All right. Well, hearing a
24 motion, and hearing a second.

25 All those in favor signify by saying yay.

1 (Chorus of yays.)

2 CHAIRMAN LA ROSA: Yay.

3 Opposed no?

4 (No response.)

5 CHAIRMAN LA ROSA: Show that the motion
6 passes.

7 Are there any other matters that need to be
8 addressed in the 01 docket?

9 MR. SANDY: I am happy to say that there are
10 not, Mr. Chair.

11 CHAIRMAN LA ROSA: Perfect.

12 Parties, anything?

13 All right. Made it easy. Seeing no
14 additional matters, then, before us, we can go
15 ahead and call this meeting adjourned.

16 Thank you to all the parties.

17 (Proceedings concluded.)

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1 CERTIFICATE OF REPORTER

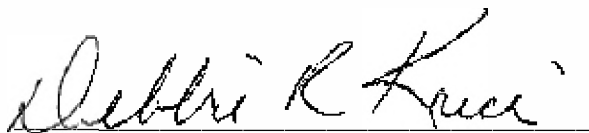
2 STATE OF FLORIDA)
3 COUNTY OF LEON)
45 I, DEBRA KRICK, Court Reporter, do hereby
6 certify that the foregoing proceeding was heard at the
7 time and place herein stated.8 IT IS FURTHER CERTIFIED that I
9 stenographically reported the said proceedings; that the
10 same has been transcribed under my direct supervision;
11 and that this transcript constitutes a true
12 transcription of my notes of said proceedings.13 I FURTHER CERTIFY that I am not a relative,
14 employee, attorney or counsel of any of the parties, nor
15 am I a relative or employee of any of the parties'
16 attorney or counsel connected with the action, nor am I
17 financially interested in the action.18 DATED this 12th day of November, 2025.
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DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH575054
EXPIRES AUGUST 13, 2028