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March 6, 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. 20250032-EI

Dear Mr. Teitzman:

Attached for electronic filing are Florida Power & Light Company's responses to Staff's First Data Request (Nos. 1-23).

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

Sincerely,

s/ Maria Jose Moncada
Maria Jose Moncada

Attachments
cc: Counsel for Parties of Record (w/ attachment)

:22728201

CERTIFICATE OF SERVICE
DOCKET 20250001-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic delivery on this 6th day of March 2025 to the following:

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QUESTION:
The following question is regarding the Utility's Generation Performance Incentive Factor (GPIF) performance:

Please describe what actions, if any, the Utility takes to ensure unit availability and/or heat rate improvement goals above typical industry practices as a result of the potential rewards or penalties associated with the GPIF.

RESPONSE:
The purpose of GPIF is to provide a monetary incentive for the efficient operation of base load generating units. As outlined in the GPIF implementation manual, GPIF units provide 80% of FPL's base load net generation. The program aligns customer and shareholder value. If GPIF targets are exceeded, customers receive fuel savings and shareholders are financially rewarded. If targets are not achieved, shareholders are financially penalized. The program has operated effectively to incent utilities to strive for the efficient operation of base load units and specifics are below.

FPL has worked aggressively to ensure unit availability and heat rate improvements above typical industry practices. For example:

FPL has implemented real-time operational monitoring technologies at PGD's Fleet Control Center for the fossil fleet, which detect issues before failure, allowing for timely and cost-effective corrective actions to maintain high reliability and fuel efficiency.

FPL has developed advanced analytical tools that provide the fossil fleet operators with increased awareness and daily feedback on startup timing, system response accuracy, and other critical parameters that may affect equipment performance. Services like overhaul work planning, execution, engineering, and technical services continue to be centralized around equipment fleet teams.

FPL has standardized operational processes and procedures for sharing and replication across the generating fleet.

FPL has implemented multiple actions including optimizing overhaul cycle intervals. By applying condition-based maintenance principles, FPL balances spending effectively while maintaining excellent reliability and fuel efficiency. This involves focusing on equipment conditions and adhering to calendar or cycle-based maintenance schedules. This is achieved through collaboration between FPL's centralized engineering experts and equipment manufacturers.

Also, FPL employs Six Sigma quality tools to drive continuous improvements across the fleet.

QUESTION:

The following question is regarding the Utility's Generation Performance Incentive Factor (GPIF) performance:

Please identify what operations and maintenance (O&M) expenses above typical industry practices are associated with achieving the unit availability and/or heat rate improvement goals associated with the GPIF. If the Utility does not engage in additional O&M expenses associated with the GPIF, please state so.

a. How are O&M expenses associated with GPIF tracked and/or estimated?

b. How are O&M expenses associated with GPIF recovered?

c. Please complete the table below providing information on the Utility's GPIF associated O&M costs for the period 2013 through 2024.

Year	GPIF Associated O&M Costs
2013	
2014	
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	
2024	

RESPONSE:

a. FPL implements the actions described in its response to Data Request No. 1 for all of its units, not just units that fall under the GPIF program.

b. Any O&M expenses associated with GPIF units are recovered along with the Company's O&M expenses through base rates.

c. See answer to subpart (a).

QUESTION:

The following question is regarding the Utility's Generation Performance Incentive Factor (GPIF) performance:

Please complete the table below providing information on the Utility's potential GPIF rewards or penalties for the period 2013 through 2024. Provide the jurisdictional maximum allowed incentive based on a 25 basis point cap, the incentive cap based on 50 percent of maximum projected fuel savings, and the maximum reward and penalty, respectively.

Year	25 Basis Point Jurisdictional Calculation ($000)	50% Maximum Fuel Savings ($000)	Maximum Reward ($000)	Maximum (Penalty) ($000)
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				

RESPONSE:

Year	25 Basis Point Jurisdictional Calculation ($000)	50% Maximum Fuel Savings ($000)	Maximum Reward ($000)	Maximum (Penalty) ($000)
2013	$ 50,967	$ 36,969	$ 36,969	$ (36,969)
2014	$ 52,044	$ 55,350	$ 52,044	$ (52,044)
2015	$ 56,491	$ 57,953	$ 56,491	$ (56,491)
2016	$ 60,288	$ 38,875	$ 38,875	$ (38,875)
2017	$ 65,800	$ 29,771	$ 29,771	$ (29,771)
2018	$ 60,329	$ 22,824	$ 22,824	$ (22,824)
2019	$ 65,782	$ 23,819	$ 23,819	$ (23,819)
2020	$ 72,645	$ 18,900	$ 18,900	$ (18,900)
2021	$ 82,735	$ 20,514	$ 20,514	$ (20,514)
2022	$ 102,385	$ 25,909	$ 25,909	$ (25,909)
2023	$ 116,051	$ 45,946	$ 45,946	$ (45,946)
2024	$ 124,005	$ 30,785	$ 30,785	$ (30,785)

QUESTION:

The following question is regarding the Utility's Generation Performance Incentive Factor (GPIF) performance:

Please complete the table below providing information on the Utility's actual GPIF rewards or penalties for the period 2013 through 2024. Provide the actual fuel savings or losses, amount of shareholder incentive or penalty, and the net ratepayer savings or losses resulting from the GPIF.

Year	Actual Fuel Savings/(Losses) ($000)	Shareholder Incentive/(Penalty) ($000)	Net Ratepayer Savings/(Losses) ($000)
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			

RESPONSE:

Year	Actual Fuel Savings/(Losses) ($000)	Shareholder Incentive/(Penalty) ($000)	Net Ratepayer Savings/(Losses) ($000)
2013	$ 23,628	$ 11,815	$ 11,814
2014	$ 49,588	$ 23,303	$ 26,285
2015	$ 64,959	$ 31,658	$ 33,301
2016	$ 19,320	$ 9,656	$ 9,664
2017	$ 11,717	$ 5,858	$ 5,859
2018	$ 17,152	$ 8,577	$ 8,575
2019	$ 16,250	$ 8,126	$ 8,125
2020	$ 12,781	$ 6,391	$ 6,390
2021	$ 16,308	$ 8,152	$ 8,156
2022	$ 21,773	$ 10,818	$ 10,954
2023	$ 22,292	$ 11,146	$ 11,146
2024	See Note 1	See Note 1	See Note 1

Values may not add up due to rounding.

Note 1: values not available at the time response was due. They will be available at the time of the 2024 GPIF True-up filing on March 14.

QUESTION:

The following question is regarding wholesale energy transactions. Please answer the question with regards to wholesale energy purchases (as reported on Schedule A-7), economy energy purchases (as reported on Schedule A-9), and wholesale energy sales (as reported on Schedule A-6).

Describe how net gains are calculated with each type of wholesale energy transaction.

RESPONSE:

Wholesale Energy Sales as reported on Schedule A-6

FPL utilizes two applications to determine marginal pricing for sales. Marginal pricing for transactions greater than one hour in duration is developed utilizing GenTrader software. Marginal pricing for transactions occurring in the next hour is developed utilizing a program called Economy A which is part of FPL's EMS system. GenTrader and Economy A are unit commitment programs that provide optimal system dispatch output data based on numerous inputs including fuel prices, generating unit factors and load parameters.

The net gain is calculated by subtracting fuel costs, FPL transmission costs, third-party transmission costs and Variable O&M from the gross revenues of the economy sale.

Please note St. Lucie Reliability Sales, as shown on Schedule A-6, are not included in the net gain calculation.

Economy Energy Purchases as reported on Schedule A-9

The marginal costs associated with economy energy purchases are calculated through the same applications and methodology described in the net gain calculations for wholesale energy sales.

The net savings on Economy Energy Purchases are calculated by subtracting the cost of the power if it were generated by the cost of purchased power and transmission costs, if applicable.

Wholesale Energy Purchases as reported on Schedule A-7

Typically, wholesale energy purchases as reported on Schedule A-7 are not included in the total Asset Optimization calculation, as they are purchases entered into to serve FPL's native load. However, if there is an opportunity to optimize FPL's system through a wholesale energy purchase, the net savings calculation will be calculated with the same applications and methodology as the economy energy purchases as reported on Schedule A-9.

QUESTION:

The following question is regarding wholesale energy transactions. Please answer the question with regards to wholesale energy purchases (as reported on Schedule A-7), economy energy purchases (as reported on Schedule A-9), and wholesale energy sales (as reported on Schedule A-6).

Describe how net gains are shared between ratepayers and shareholders with each type of wholesale energy transaction. As part of your response, describe how and where recovery of associated costs and benefits of the transaction occurs.

RESPONSE:

FPL calculates its total net gains as the sum of all approved asset optimization activities pursuant to Order Nos. PSC-13-0023-S-EI, PSC-2016-0560-AS-EI and PSC-2021-0446-S-EI. The sharing mechanism is then calculated pursuant to Order No. PSC-2021-0446-S-EI, where three annual savings thresholds are set to allow for (1) FPL's customers to receive 100% of the incentive mechanism gain up to $42.5 million; (2) FPL's customers to receive 40% and FPL to receive 60% of incremental mechanism gains between $42.5 million and $100 million; and (3) FPL and its customers to each receive 50% of incremental mechanism gains in excess of $100 million. The thresholds listed apply to all asset optimization activities, not only wholesale energy transactions.

Pursuant to Order No. PSC-13-0023-S-EI, annually, as part of the fuel cost recovery clause, FPL files final true-up schedules showing its total gains, monthly detail on wholesale power and monthly detail on additional asset optimization activities, as well as incremental costs associated with the asset optimization program. Additionally, FPL files a schedule providing details of the sharing mechanism calculation for that year.

Customer benefits, shareholder benefits, marginal costs and variable O&M associated with the transaction are initially included as part of the Fuel Cost Recovery Clause filing in FPL's Fuel and Purchased Power Costs Recovery projection for the subsequent year, on the E-Schedules. On a monthly basis both benefits and costs are actualized and tracked through FPL's A-Schedules. Transmission costs and power options premiums are recovered through the Capacity Clause.

QUESTION:

The following questions is regarding wholesale energy transactions. Please answer the question with regards to wholesale energy purchases (as reported on Schedule A-7), economy energy purchases (as reported on Schedule A-9), and wholesale energy sales (as reported on Schedule A-6).

Describe whether there is the risk of net losses with each type of wholesale energy transaction. As part of your response, describe if a net loss could occur with any particular type wholesale energy transaction, and if so, how would it be recovered.

a. **If net losses have occurred associated with any wholesale energy transactions within the 2013 through 2024 period, describe the circumstances resulting in the net losses for each relevant transaction or group of transactions.**

b. **If net losses have occurred associated with any wholesale energy transactions within the 2013 through 2024 period, identify the annual amount of losses for each type of wholesale energy transaction.**

RESPONSE:

The asset optimization activities approved in Order Nos. PSC-13-0023-S-EI, PSC-2016-0560-AS-EI and PSC-2021-0446-S-EI all have associated risks, including market risk, credit risk and operational risk. FPL recognizes these types of risks introduce the possibility of monetary losses and has put safeguards in place to address them.

The execution of asset optimization activities are strictly governed by Risk Management Policies and Procedures, which are filed with this Commission annually, and are ultimately overseen by FPL's Exposure Management Committee (EMC). Market risk limits, such as tenor, open positions, among others, have been set to help mitigate risk. FPL manages credit risk through appropriate creditworthiness reviews, monitoring and the inclusion of contractual risk mitigation terms and conditions whenever possible. Operational risk due to weather uncertainty, changes in forecasts and plant availability are addressed through the retention of a portion of gas transportation or storage capacity to cover forecast errors. FPL utilizes forecasted and historical data to further determine if system conditions allow for the execution of asset optimization activities. Typically, given the uncertainty of weather and unit availability, FPL executes transactions that are short-term in nature. Finally, contractual provisions, such as the ability to "call-back" capacity releases, are used to help mitigate certain risks as much as possible while maintaining the value of the transaction(s).

FPL has not experienced a net loss in any asset optimization category. However, to the extent that monetary losses were incurred in any individual transactions or overall, in any category, FPL's customers would experience less total benefits from the asset optimization measures than they otherwise would have, and FPL's ability to reach the threshold(s) and potentially share in the overall benefits would be impaired.

QUESTION:

The following question is regarding wholesale energy transactions. Please answer the question with regards to wholesale energy purchases (as reported on Schedule A-7), economy energy purchases (as reported on Schedule A-9), and wholesale energy sales (as reported on Schedule A-6).

Describe what incremental costs are associated with wholesale energy transactions, (staffing, software, hardware, subscriptions/memberships, data purchasing, etc.) excluding variable O&M. As part of your response, provide an estimate of how many incremental personnel work on wholesale energy transactions.

RESPONSE:

Incremental O&M costs incurred to manage the incentive mechanism are broadly categorized as either personnel or software and hardware expenses as shown on Schedule A2. The personnel expenses include employee payroll and payroll related costs such as benefits, taxes, and overheads. They also include employee related expenses such as subscriptions, education and training, and technology. Software and hardware expenses support the trading and risk management systems used to record and execute both power and gas related optimization transactions.

Incremental personnel and systems/hardware expenses support all of the activities included in the incentive mechanism. While these costs cannot be assigned to individual transactions, one and one-half additional personnel have been added to support the power related strategies included in the incentive mechanism. The total incremental O&M costs for incentive mechanism transactions, including wholesale energy transactions, are spread across all program activities and included on Schedule A2. Costs for existing operational employees working on optimization activities are recovered through FPL's base rates.

QUESTION:

The following question is regarding wholesale energy transactions. Please answer the question with regards to wholesale energy purchases (as reported on Schedule A-7), economy energy purchases (as reported on Schedule A-9), and wholesale energy sales (as reported on Schedule A-6).

Describe how incremental costs are tracked by the Utility, or if not, why not. As part of your response, describe if these costs can be allocated to a single type of wholesale energy transaction or spread across multiple categories.

RESPONSE:

Incremental O&M costs incurred to manage the incentive mechanism are included in Power, Gas, and Systems Cost Centers. The costs accumulated in these Cost Centers roll up to Business Area AO4. Expenses summarized in AO4 are included as incremental O&M costs recovered through the Fuel Clause. These costs can be further separated into either personnel or software/hardware costs.

Incremental personnel and systems/hardware expenses support all of the activities included in the incentive mechanism. These costs cannot be assigned to specific activities. Instead, total incremental O&M costs are spread across all incentive mechanism activities.

QUESTION:

The following question is regarding wholesale energy transactions. Please answer the question with regards to wholesale energy purchases (as reported on Schedule A-7), economy energy purchases (as reported on Schedule A-9), and wholesale energy sales (as reported on Schedule A-6).

Describe where incremental costs for each type of wholesale energy transactions are recovered in base rates or cost recovery clauses.

RESPONSE:

Incremental O&M costs incurred to manage the incentive mechanism support all of the activities included in the program. These expenses are included on Schedule A2 and recovered through the Fuel Clause. Costs for existing operational employees working on optimization activities are recovered through FPL's base rates.

QUESTION:

The following question is regarding wholesale energy transactions. Please answer the question with regards to wholesale energy purchases (as reported on Schedule A-7), economy energy purchases (as reported on Schedule A-9), and wholesale energy sales (as reported on Schedule A-6).

Please complete the table below providing information on the Utility's actual incremental costs for wholesale energy transactions for the period 2013 through 2024. Provide the annual cost for variable O&M associated with whole energy sales, the incremental staffing, software/hardware, and all other costs associated with wholesale energy transactions.

Year	Wholesale Sale Variable O&M Costs	Incremental Staffing Costs	Incremental Software/Hardware Costs	All Other Incremental Costs
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				

RESPONSE:

Year	Wholesale Sale Variable O&M Costs	Incremental Staffing Costs[1]	Incremental Software/ Hardware Costs(1)	All Other Incremental Costs
2013	$2,160,452	$263,407	$0	$0
2014	$2,304,384	$406,314	$54,114	$0
2015	$2,563,924	$407,058	$66,492	$0
2016	$2,671,992	$428,815	$55,490	$0
2017	$1,275,624	$425,123	$278,801	$0
2018	$1,611,119	$458,689	$57,762	$0
2019	$1,754,273	$474,309	$58,755	$0
2020	$1,827,307	$480,859	$31,467	$0
2021	$2,103,997	$495,972	$0	$0
2022	$1,311,977	$527,488	$0	$0
2023	$1,603,947	$517,530	$0	$0
2024	$1,253,117	$864,547	$0	$0

(1) Incremental costs are spread across both energy and fuel optimization activities. Costs are not separately associated with wholesale energy transactions.

QUESTION:

The following question is regarding wholesale energy transactions. Please answer the question with regards to wholesale energy purchases (as reported on Schedule A-7), economy energy purchases (as reported on Schedule A-9), and wholesale energy sales (as reported on Schedule A-6).

Please complete the table below providing information on the Utility's actual wholesale energy purchases, exclusive of economy energy purchases reported on Schedule A7, for the period 2013 through 2024. Provide the annual amount of wholesale purchases (in megawatt-hours and dollars), the total cost if generated, net fuel savings, avoided variable O&M costs, and total net gains.

Year	Wholesale Purchases (MWh)	Wholesale Purchases ($000)	Total Cost If Generated ($000)	Fuel Savings ($000)	Variable O&M Costs ($000)	Net Gains ($000)
2013						
2014						
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						

RESPONSE:

Please see the table included on page 2 of this Answer.

Year	Wholesale Purchases (MWh)	Wholesale Purchases ($000)	Total Cost if Generated ($000)[1]	Fuel Savings ($000)	Variable O&M Costs ($000)[3]	Net Gains ($000)[4]
2013	5,105,913	$178,944	N/A	N/A	N/A	N/A
2014	5,443,638	$203,951	$279	$230[2]	N/A	$230
2015	5,651,975	$198,338	N/A	N/A	N/A	N/A
2016	3,176,255	$91,394	N/A	N/A	N/A	N/A
2017	2,955,375	$91,685	N/A	N/A	N/A	N/A
2018	1,442,554	$30,925	N/A	N/A	N/A	N/A
2019	1,636,731	$31,697	N/A	N/A	N/A	N/A
2020	1,528,008	$28,306	N/A	N/A	N/A	N/A
2021	1,468,790	$34,911	N/A	N/A	N/A	N/A
2022	6,300,081	$328,122	N/A	N/A	N/A	N/A
2023	3,819,238	$120,560	N/A	N/A	N/A	N/A
2024	3,111,028	$96,205	N/A	N/A	N/A	N/A

(1) Total Cost if Generated was calculated for the 2014 Seminole Electric transaction of 8400 MWh.

(2) Fuel Savings only applies to the 2014 Seminole Electric transaction.

(3) Variable O&M Costs are not typically calculated for A7 transactions.

(4) Net Gains (purchase amount - cost if generated) are not typically calculated for A7 transactions.

QUESTION:

The following question is regarding wholesale energy transactions. Please answer the question with regards to wholesale energy purchases (as reported on Schedule A-7), economy energy purchases (as reported on Schedule A-9), and wholesale energy sales (as reported on Schedule A-6).

Please complete the table below providing information on the Utility's actual wholesale energy economy purchases reported on Schedule A9, for the period 2013 through 2024. Provide the annual amount of wholesale purchases (in megawatt-hours and dollars), the total cost if generated, net fuel savings, avoided variable O&M costs, and total net gains.

Year	Wholesale Purchases (MWh)	Wholesale Purchases ($000)	Total Cost If Generated ($000)	Fuel Savings ($000)	Variable O&M Costs ($000)	Net Gains ($000)
2013						
2014						
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						

RESPONSE:

Please see the table on page 2 of this Answer.

Year	Wholesale Purchases (MWh)	Wholesale Purchases ($000)	Total Cost If Generated ($000)	Fuel Savings ($000)[2]	Variable O&M Costs ($000)[3]	Net Gains ($000)
2013	147,977	$6,778	$9,984	$3,206	N/A	$3,206
2014	413,070	$20,444	$30,742	$10,298	N/A	$10,528
2015	523,866	$22,232	$31,810	$9,578	N/A	$9,578
2016	1,943,480	$70,536	$96,029	$25,494	N/A	$25,494
2017	621,439	$25,118	$32,939	$7,821	$404	$7,821
2018	232,638	$10,646	$18,590	$7,943	$151	$7,943
2019	551,187	$25,535	$40,450	$14,914	$358	$14,914
2020	258,262	$9,726	$12,466	$2,741	$168	$2,741
2021	394,542	$19,450	$22,078	$2,628	$256	$2,628
2022	257,979	$43,855	$60,783	$16,928	$124	$16,928
2023	159,923	$9,433	$18,008	$8,669	$77	$8,669
2024[1]	117,408	$7,090	$13,471	$6,381	$56	$6,381

(1) Information for 2024 is preliminary.
(2) Fuel Saving for 2014 includes savings from Seminole Electric transaction.
(3) Variable O&M Costs for wholesale purchases were not included in the Asset Optimization Program during the 2013-2016 period.

QUESTION:
The following question is regarding wholesale energy transactions. Please answer the question with regards to wholesale energy purchases (as reported on Schedule A-7), economy energy purchases (as reported on Schedule A-9), and wholesale energy sales (as reported on Schedule A-6).

Please complete the table below providing information on the Utility's actual wholesale energy sales, for the period 2013 through 2024. Provide the annual total of wholesale sales (in megawatt-hours and dollars), associated fuel costs, variable O&M costs, and net gains.

Year	Wholesale Sales (MWh)	Wholesale Sales ($000)	Total Fuel Cost ($000)	Variable O&M Costs ($000)	Wholesale Sale Net Gains ($000)
2013					
2014					
2015					
2016					
2017					
2018					
2019					
2020					
2021					
2022					
2023					
2024					

RESPONSE:
Please see the table included on page 2 of this Answer.

Year	Wholesale Sales (MWh)	Wholesale Sales ($000)	Total Fuel Cost ($000)	Variable O&M Costs ($000)	Wholesale Sale Net Gains ($000)[2]
2013	1,944,763	$68,401	$50,765	$2,160	$11,153
2014	2,494,290	$128,785	$77,852	$2,304	$43,476
2015	2,391,991	$84,187	$52,401	$2,564	$23,398
2016	2,478,700	$72,250	$44,338	$2,672	$18,695
2017	1,962,498	$67,716	$44,242	$1,276	$17,278
2018	2,478,644	$97,081	$56,331	$1,611	$32,463
2019	2,698,881	$85,404	$52,211	$1,754	$23,922
2020	2,811,241	$75,134	$43,036	$1,827	$25,419
2021	3,236,919	$133,882	$83,651	$2,104	$40,121
2022	2,733,252	$186,568	$108,804	$1,312	$66,581
2023	3,341,557	$165,137	$89,013	$1,604	$63,045
2024[1]	2,985,567	$132,592	$68,873	$1,253	$50,410

(1) Information for 2024 is preliminary.
(2) The Wholesale Sale Net Gains include power option premiums.

QUESTION:

The following question is regarding wholesale energy transactions. Please answer the question with regards to wholesale energy purchases (as reported on Schedule A-7), economy energy purchases (as reported on Schedule A-9), and wholesale energy sales (as reported on Schedule A-6).

Please complete the table below providing information on the Utility's actual wholesale energy sales incentives, for the period 2013 through 2024. Provide the annual net gains, the three year rolling average of wholesale sales, the amount of shareholder incentives received for wholesale sales, and the net ratepayer savings. For those years under which the Utility utilized an Asset Optimization Mechanism, exclude the shareholder incentives and net ratepayer savings values.

Year	Wholesale Sale Net Gains ($000)	Three Year Rolling Average Threshold ($000)	Shareholder Incentive ($000)	Net Ratepayer Savings ($000)
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				

RESPONSE:

Please see the table included on Page 2 of this Answer.

Year	Wholesale Sale Net Gains ($000)	Three Year Rolling Average Threshold ($000)	Shareholder Incentive ($000)	Net Ratepayer Savings ($000)(1)
2013	$11,153	N/A	$0	$0
2014	$43,475	N/A	$0	$0
2015	$23,397	N/A	$0	$0
2016	$18,695	$26,008	$0	$0
2017	$17,277	$28,522	$0	$0
2018	$32,462	$19,790	$0	$0
2019	$23,922	$22,811	$0	$0
2020	$25,419	$24,554	$0	$0
2021	$40,120	$27,268	$0	$0
2022	$66,580	$29,820	$0	$0
2023	$63,044	$44,040	$0	$0
2024	$50,409	$56,581	$0	$0

(1) FPL utilized an Asset Optimization Mechanism during the entire period requested.

QUESTION:

The following question is regarding activities using ratepayer-supported assets to produce net gains, such as those activities included within the various Asset Optimization Mechanisms.

Provide a list of activities in which the Utility has attempted to produce net gains using ratepayer supported assets. These activities may include: release of electric transmission capacity, release of natural gas pipeline or storage capacity, sales of fuel by type and location, financial instruments associated with fuel, sales of renewable energy credits, sale of emissions credits, or other similar activities.

For each activity identified above, please provide the following information:

a. **Describe the activity and how the net gains are calculated.**

b. **Describe whether there is the risk of net losses with the activity. As part of your response, describe if a net loss could occur with the activity, and if so, how would it be recovered.**

   i. **If net losses have occurred associated with the activity within the 2013 through 2024 period, describe the circumstances resulting in the net losses.**

   ii. **If net losses have occurred associated with the activity within the 2013 through 2024 period, identify the annual amount of losses**

c. **Describe whether the activity was engaged in prior to the adoption of the Utility's Asset Optimization Mechanism. If so, provide the following information:**

   i. **When did the Utility begin engaging in this activity?**

   ii. **How were net gains allocated between ratepayers and shareholders?**

   iii. **Where would cost recovery for these benefits occur (such as base rates or a cost recovery clause)?**

RESPONSE:

a.

Gains on Economy Sales

Please see response to Data Request No. 5

Savings from Economy Purchases

Please see response to Data Request No. 5

Power Option Premiums
FPL assesses its electric capacity needs using demand forecasts, unit availability, and weather conditions. When excess capacity is available, FPL may reserve a portion for third parties for a short duration. These capacity reserves support in-state utilities during unplanned outages or unexpected load increases.

The gain for capacity reserves is the premium paid to reserve the capacity. As the capacity is provided as a busbar product, pricing is subject to FPL's cost-based tariff.

Back-to-Back Power Sales
At times FPL may buy power from one entity and sell to another entity for gain. The gain from a Back-to-Back Power sale is the difference between the cost of the purchased power and the sales price.

Delivered City-Gate Sales
At times, FPL will make natural gas sales in the Market Area when its natural gas transportation capacity is not needed for its own requirements. The opportunity for these types of sales is more limited during summer months due to FPL's high utilization of its firm gas transportation and the necessity to retain a portion of its gas transportation to cover forecast errors. If FPL can execute this type of sale, the gain will benefit customers by reducing overall fuel expenses.

For all Market Area sales, FPL takes into consideration its projected fuel burns, known pipeline scheduled maintenance, weather conditions and Market Area demand at the time. Additionally, FPL clarifies with all counterparties that delivered Market Area sales are executed on a secondary firm basis, meaning FPL reserves the right to curtail such transactions if certain market conditions arise, such as an allocation. FPL will not jeopardize its own reliability to serve Market Area sales.

The gain from a delivered city-gate natural gas sale using existing transport is calculated by subtracting the cost of natural gas that is purchased for the sale and the variable transportation costs to the delivery point on the relevant pipeline from the revenue received for the sale.

Production Area Sales
Production Area sales are made using FPL's existing upstream gas transportation capacity during periods when it is not needed to serve FPL's native load. When there is a sufficient price difference between two different locations, an arbitrage opportunity exists to either (a) buy gas at the lower cost location and transport and sell the gas at the more expensive location for a gain, net of transport, or (b) sell FPL's existing procurement gas at a higher price at the more expensive location and buy gas at the lower cost location.

The gain from a Production Area natural gas sale is calculated by subtracting the cost of natural gas that is purchased for the sale and the variable transportation costs to the delivery point on the relevant pipeline from the revenue received for the sale.

Capacity Release of Firm Transport

FPL carefully evaluates its capacity needs based on fuel consumption forecasts, available firm capacity, unit availability and weather conditions. FPL may release a small portion of its gas transportation capacity for a short duration when it is not needed for its own requirements. Capacity releases are typically done through posting on a pipeline's electronic bulletin board (EBB) which is open for bidding to all pipeline-approved shippers. It is important to note that all capacity releases are "re-callable," meaning FPL retains the right to call back the capacity for its own requirements.

The gain from a capacity release of idle natural gas transport is the revenue received for the sale.

Natural Gas Option Premiums

FPL's natural gas procurement strategy utilizes a mixture of term, month-ahead and daily gas purchases. Given the size of FPL's natural gas portfolio, procurement must be spread across these three categories to ensure that reliable supply, in sufficient quantities to match demand, is delivered each day. When determining the appropriate amount of volume to purchase within each category, FPL considers numerous factors, including projected consumption, seasonality, market liquidity, and operation constraints. There is a certain amount of price risk inherent in FPL's procurement strategy because of the unpredictable relationship among term, monthly and daily settlement prices. FPL cannot eliminate the risk but has been able to monetize a portion of the risk for the benefit of customers by selling put options to suppliers. The purchasers of the put options have the right to deliver a set volume to FPL at a predetermined index price and in exchange for this right, FPL receives an option premium. These transactions do not increase FPL's price risk, while FPL customers receive an additional benefit from the proceeds of selling the put options, which are credited against fuel expense. FPL would not be able to capture this benefit through its normal procurement process.

The gain from Natural Gas Options are the premiums received for the transaction.

Natural Gas Storage

FPL primarily utilizes its natural gas storage capacity to ensure the reliability of supply and to help manage the daily consumption "swings," due to weather and unit availability changes. However, given the dynamic nature of the natural gas market and occasional pricing imbalances, FPL is also able to optimize idle storage capacity, when available. FPL typically executes these types of transactions when full gas storage volumes are not required. The revenue that is generated from gas storage optimization activities directly benefits customers by reducing overall fuel expenses.

FPL's optimization strategy for gas storage is focused on capturing price differences in the forward curve. Natural gas prices are volatile and highly seasonal, with prices exhibiting contango and backwardation at different points in time. Contango describes a market where spot prices are lower than future prices. Backwardation describes a market where spot prices are higher than future prices. The market conditions present the opportunity for storage optimization, if the following conditions exist for FPL:

(1) The price spread between the lowest price and the highest price on the forward curve is sufficient to cover fuel and variable costs associated with utilizing storage capacity.

(2) FPL is confident that it will not require the volume of storage being optimized for the term of the transaction. However, in case of an emergency, all physical gas in the storage can be withdrawn to supply FPL's power plant needs.

(3) Sufficient liquidity is present in the market to ensure that FPL can execute both sides of the transaction to lock in the gain.

Gains from storage optimization can be derived from different types of transactions; however, FPL typically executes transactions that capture value from price differences in the forward curve. Under these types of transactions, FPL locks in both sides of each transaction (purchase and sale) to capture the gain. For example, if spot prices are lower than future prices, FPL could purchase natural gas, store the gas, and sell the gas later. The purchase and sale are executed at the same time. The gain for this transaction is calculated by subtracting the cost of the gas and any injection/variable transportation costs from the revenue received from the sale.

Gas Asset Management Agreements (AMA)
FPL uses AMAs to provide incremental value for FPL's customers. Third parties pay FPL for the right to manage FPL's gas transportation capacity (typically upstream capacity) while still delivering gas supply to FPL at the equivalent price at which FPL would have received by utilizing the transport on its own. Under these arrangements, FPL's customers receive 100% of the savings of the upstream receipt point gas under the transportation contract. In addition, FPL customers receive the benefit of the AMA fee. FPL can structure each AMA to deliver value to its customers while maintaining the reliability of its natural gas supply.

As previously stated, under an AMA, FPL releases transportation capacity to a replacement shipper on a temporary, recallable basis. In exchange, the replacement shipper pays FPL a fee during the term of the agreement.

The gain on an AMA is the fee that is paid to FPL by the replacement shipper.

Delivered Natural Gas Savings
FPL may swap transportation capacity on one pipeline for transportation on another pipeline that will provide better economics for the same period.

The gain from Delivered Natural Gas Savings is the price differential of the swap.

Operational Balancing Agreement (OBA)
To provide more efficient operations at different gas delivery points FPL may enter into a balancing agreement with a third-party to manage any differences between scheduled quantities and actual deliveries at the agreed upon point.

The gain for an OBA is the fee provided for the balancing agreement.

Renewable Energy Credit (REC) Sales
A REC represents proof that one megawatt-hour of electricity was generated from a renewable energy resource. As a renewable energy provider, FPL generates power from its solar assets creating RECs for its personal consumption and, if available, for sale to third parties. FPL sells its RECs in the spot and forward markets. FPL engages in forward market sales to take advantage of current prices with future delivery obligations.

The gain from REC sales is the revenue received. For spot REC sales this occurs in the same year of the sale. For forward REC sales, revenue is only recognized at the time of future delivery of the RECs that were sold.

Coal Sales
Jacksonville Electric Authority (JEA) requested to buy coal inventory from St. Johns River Power Plant (SJRPP) to address a fuel emergency at their adjacent Northside Plant. The SJRPP facility had enough inventory to accommodate the request. However, neither owner, JEA or FPL, had the right to exclusively use any SJRPP asset, the coal stockpile being the asset in this case. FPL and JEA ultimately executed an agreement in response to their request to purchase a small amount of coal for the Northside Plant. FPL was able to negotiate a transaction fee as part of the agreement.

The gain from this transaction was the revenue received for the transaction fee.

NOx and Emission Sales
In September 2016, the Environmental Protection Agency (EPA) published the final Cross-State Air Pollution Rule (CSAPR) Update, which removed Florida from CSAPR and created two new trading groups for states remaining in CSAPR.

The rule update allowed the conversion of banked allowances to be sold in the market for a gain as they were not needed for compliance.

The gain from the transaction was the revenue received for the sale.

b. Please see response to Data Request No. 7

c. FPL engaged in economy power sales and economy power purchases prior to the adoption of its Asset Optimization Mechanism. Prior to the adoption of the current Asset Optimization mechanism there were two incentive mechanisms applicable to economy sales 1) Order No. 12923, issued January 24, 1984, established an incentive mechanism that calculated gains as the result of a "split-the-savings" methodology which would allow economy energy sales profits to be divided between customers and shareholders on a 80%-20% basis, respectively and 2) Order No. PSC-00-1744-PAA-EI, issued September 26, 2000, established a three year moving average threshold, allowing for FPL to split all gains greater than the threshold, through an 80%-20% split between customers and shareholders, respectively. All other activities were performed after the adoption of FPL's Asset Optimization Mechanism.

QUESTION:

The following question is regarding activities using ratepayer-supported assets to produce net gains, such as those activities included within the various Asset Optimization Mechanisms.

Describe how incremental costs are tracked by the Utility, or if not, why not. As part of your response, describe if these costs can be allocated to a single type of activity or spread across multiple categories.

RESPONSE:

Incremental O&M costs incurred to manage the incentive mechanism are included in Power, Gas, and Systems Cost Centers. The costs accumulated in these Cost Centers then roll up to Business Area AO4. Expenses summarized in AO4 are included as incremental O&M costs. These costs can be further separated into either personnel or software/hardware costs.

Incremental personnel and systems/hardware expenses support all of the activities included in the incentive mechanism. These costs cannot be assigned to specific activities. Instead, total incremental O&M costs are spread across all incentive mechanism activities.

QUESTION:

The following question is regarding activities using ratepayer-supported assets to produce net gains, such as those activities included within the various Asset Optimization Mechanisms.

Describe where incremental costs for each type of activity are recovered in base rates or cost recovery clauses.

RESPONSE:

Incremental O&M costs incurred to manage the incentive mechanism support all of the activities included in the program. These expenses are included on the A2 and recovered through the Fuel and Purchased Power Cost Recovery Clause.

QUESTION:

The following question is regarding activities using ratepayer-supported assets to produce net gains, such as those activities included within the various Asset Optimization Mechanisms.

Please complete the table below providing information on the Utility's actual incremental costs for asset optimization activities. Provide the annual cost for incremental staffing, software/hardware, and all other costs associated with wholesale energy transactions.

Year	Incremental Staffing Costs	Incremental Software/Hardware Costs	All Other Incremental Costs	Total Incremental Costs
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				

RESPONSE:

Please see the table on page 2 of this Answer.

Year	Incremental Staffing Costs	Incremental Software/ Hardware Costs	All Other Incremental Costs	Total Incremental Costs(1)
2013	$263,407	$0	$0	$263,407
2014	$406,314	$54,114	$0	$460,428
2015	$407,058	$66,492	$0	$473,550
2016	$428,815	$55,490	$0	$484,305
2017	$425,123	$278,801	$0	$703,924
2018	$458,689	$57,762	$0	$516,451
2019	$474,309	$58,755	$0	$533,064
2020	$480,859	$31,467	$0	$512,326
2021	$495,972	$0	$0	$495,972
2022	$527,488	$0	$0	$527,488
2023	$517,530	$0	$0	$517,530
2024	$864,547	$0	$0	$864,547

(1) Incremental costs are spread across both energy and fuel optimization activities. Costs are not separately associated with wholesale energy transactions.

QUESTION:

The following question is regarding activities using ratepayer-supported assets to produce net gains, such as those activities included within the various Asset Optimization Mechanisms.

Please complete the table below providing information on the Utility's actual asset optimization activities, for the period 2013 through 2024. Provide the annual savings by activity and total activity savings.

Year	Activity n Savings ($000)	Activity n+1 Savings ($000)	. . .	Total Activity Savings ($000)
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				

RESPONSE:

Please see the table included as Attachment No. 1.

Year	Wholesale Sales Gains ($000)	Wholesale Purchases Savings ($000)	Power Option Premiums ($000)	Natural Gas Delivered City-Gate Sales ($000)	Natural Gas Production Areas Sales ($000)	Natural Gas Capacity Release Firm Transport ($000)	Natural Gas Option Premiums ($000)	Natural Gas Storage Optimization ($000)	Natural Gas AMA Gains ($000)	OBA Service Gains ($000)	Deliverd Natural Gas Savings ($000)	Electric Transmission Capacity Release Firm Transmission ($000)	Coal Sales Gains ($000)	NOX Emissions Sales ($000)	Back to Back Power Sale ($000)	Solar REC Sales ($000)	Total Savings / Gains ($000)
2013	$10,682	$3,206	$471	$909	$2,650	$679	$3,163	$159	$1,570	$0	$0	$1,077	$0	$0	$0	$0	$24,564
2014	$43,437	$10,528	$38	$744	$964	$1,007	$5,896	$1,030	$2,302	$0	$0	$1,660	$20	$0	$0	$0	$67,627
2015	$23,197	$9,578	$201	$1,260	$472	$856	$6,964	$725	$1,545	$0	$0	$2,086	$0	$0	$0	$0	$46,884
2016	$17,090	$25,494	$1,605	$2,553	$466	$264	$6,731	$1,083	$816	$0	$1,977	$4,100	$0	$657	$0	$0	$62,836
2017	$14,911	$7,821	$2,367	$3,538	$603	$3,218	$8,945	$861	$1,478	$0	$0	$0	$0	$119	$0	$0	$43,862
2018	$29,168	$7,943	$3,295	$5,753	$959	$1,871	$8,121	$3,308	$1,987	$0	$0	$0	$0	$0	$0	$0	$62,404
2019	$22,201	$14,914	$1,722	$2,871	$764	$2,188	$7,503	$721	$2,365	$0	$0	$0	$0	$1	$0	$0	$55,249
2020	$23,960	$2,741	$1,460	$1,919	$800	$2,839	$7,548	$1,679	$3,161	$28	$0	$0	$0	$0	$0	$0	$46,135
2021	$36,551	$2,628	$3,569	$1,719	$539	$3,614	$7,784	$2,393	$4,247	$48	$0	$0	$0	$0	$0	$0	$63,093
2022	$61,647	$16,928	$4,934	$2,601	$2,268	$5,063	$10,021	$1,546	$4,890	$48	$0	$0	$0	$0	$216	$20,020	$130,180
2023	$60,111	$8,669	$2,933	$2,010	$300	$6,189	$16,962	$916	$9,063	$48	$0	$0	$0	$0	$0	$16,006	$123,207
2024 (*)	$50,410	$6,381	$0	$3,794	$1,113	$5,635	$21,366	$2,870	$13,480	$48	$0	$0	$0	$0	$0	$19,951	$125,048

(*) Information for 2024 is preliminary.

QUESTION:

The following question is regarding activities using ratepayer-supported assets to produce net gains, such as those activities included within the various Asset Optimization Mechanisms.

Please complete the table below providing information on the Utility's actual asset optimization activities outside of an Asset Optimization Mechanism, for the period 2013 through 2024. Provide the annual total activity savings, incremental costs, amount of shareholder incentives, and net ratepayer savings. For those years under which the Utility utilized an Asset Optimization Mechanism, exclude the shareholder incentives and net ratepayer savings values.

Year	Total Activity Savings ($000)	Incremental Costs ($000)	Shareholder Incentive ($000)	Net Ratepayer Savings ($000)
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				

RESPONSE:

Year	Total Activity Savings[1]	Incremental Costs	Shareholder Incentive	Net Ratepayer Savings[2]
2013	$5,662,923.60	$0.00		
2014	$8,954,591.23	$0.00		
2015	$6,893,272.21	$495,548.81		
2016	$10,908,568.87	$1,538,127.81		
2017	$6,639,509.17	$2,319,864.72		
2018	$6,624,240.46	$2,667,129.96		
2019	$10,187,237.24	$2,496,478.72		
2020	$7,815,518.07	$686,835.94		
2021	$10,244,738.72	$999,315.68		
2022	$10,926,044.17	$5,475,173.75		
2023	$14,382,850.61	$4,757,584.00		
2024	$14,609,108.37	$3,238,784.06		

1. Savings made up of Fuel Oil Tank Leases, Third-Party Biodiesel Sales and Transmission Credits to the Capacity Clause associated with Economy Power Sales.
2. FPL utilized an Asset Optimization Mechanism during the entire period requested.

QUESTION:
The following question is regarding the Utility's Asset Optimization Mechanisms.

For each Order approving an Asset Optimization Mechanism, provide the following information:

a. Please describe how the Utility's threshold levels were determined. If they were partially based on historic savings, please identify what categories of savings and for what time period.

b. Describe how the Utility's current sharing percentages by threshold were determined.

RESPONSE:
a.

Docket 120015-EI, Order No. PSC-13-0023-S-EI, Issued January 14, 2013:

As part of its 2013 Projection Filing in Docket No. 120001-EI, filed on August 31, 2012, FPL projected gains on wholesale sales of $4,238,116 and savings on wholesale purchases of $30,907,083 for 2013. These projections for 2013 were reflective of current market conditions, as well as the continued change in FPL's generation fleet. The sum of gains from projected wholesale sales and projected savings from wholesale purchases determined the "Customer Savings Threshold" of $36 million. The "Additional Customer Savings" threshold of $10 million was added to include potential savings from asset optimization measures included in the incentive proposal. The net threshold level of $46 million was a "stretch" goal. The actual levels of benefits that can be achieved are driven by numerous factors, including random events that significantly impact market conditions. FPL must be ready to capitalize on all opportunities that exist, regardless of what was projected for each optimization measure. The remaining threshold levels were determined as part of the proposed stipulation and settlement process.

Docket 160088-EI, Order No. PSC-16-0560-AS-EI, Issued December 15, 2016:

The threshold levels established in 2012 were modified in 2016 to reflect FPL's actual gains from 2013-2015 as well as the expiration of the Unit Power Sales ("UPS") contract with Southern Company. When the sharing threshold was set in 2012, it reflected FPL's ability to realize gains from optimizing the UPS contract with Southern Company and associated electric transmission access rights. The $46 million threshold proved to be reasonable, as FPL averaged $46.4 million in gains over the three years from 2013-2015. However, the UPS contract expired at the end of 2015 and was not replaced because the offered renewal terms were not economically attractive for FPL and its customers. Of the $46.4 million in average annual gains from 2013-2015, $10.5 million had been UPS-related. Because FPL no longer had the opportunity to realize UPS-related gains in the future, it was appropriate to

reduce the sharing threshold to reflect the loss of that opportunity. Subtracting the $10.5 million average UPS gain from the sharing threshold of $46 million would result in an adjusted threshold of $35.5 million, which FPL proposed to round up to $36 million. The initial threshold level was set at $40 million as part of the proposed stipulation and settlement process. The remaining threshold levels were continued from the Pilot Incentive Mechanism authorized in by Order PSC-13-0023-S-EI.

Docket 20210015-EI, Order No. PSC-2021-0446-S-EI, Issued December 2, 2021:

The threshold levels established in 2016 were modified in 2021. As with other parameters in the settlement, the $42.5 million initial sharing threshold was established through negotiations with the signatories to the agreement. With any settlement, there are gives and takes and the threshold value was established as part of the broader set of negotiations. The remaining threshold levels were continued from the Pilot Incentive Mechanism authorized in by Order PSC-13-0023-S-EI.

b. FPL's sharing percentages by threshold were developed as part of an overall settlement that was approved by the Commission in Docket 120015-EI, Order No. PSC-13-0023-S-EI, Issued January 14, 2013. The sharing percentages have remained consistent since that time, though, as explained above, the thresholds were slightly modified.

QUESTION:
The following question is regarding the Utility's Asset Optimization Mechanisms.

Please complete the table below providing information on the Utility's actual Asset Optimization Mechanism activities savings and costs, for the period 2013 through 2024. Provide the annual total wholesale sale savings, wholesale purchase savings, asset optimization activity savings, incremental costs, net total asset optimization activity savings, the amount of shareholder incentives, and net ratepayer savings.

Year	Wholesale Purchase Savings ($000)	Wholesale Sale Savings ($000)	Asset Optimization Savings ($000)	Incremental Costs ($000)	Total AOM Savings ($000)	Shareholder Incentive ($000)	Net Ratepayer Savings ($000)
2013							
2014							
2015							
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
2024							

RESPONSE:
Please see the table included as Attachment No. 1.

Year	Wholesale Purchase Savings ($000)	Wholesale Sale Savings ($000)	Asset Optimization Savings ($000)	Incremental Costs ($000)[2]	Total AOM Savings ($000)	Shareholder Incentive ($000)	Net Ratepayer Savings ($000)
2013	$3,206	$11,153	$10,205	$263	$24,564	$0	$24,564
2014	$10,528	$43,476	$13,623	$460	$67,627	$12,976	$54,651
2015	$9,578	$23,398	$13,909	$474	$46,884	$531	$46,354
2016	$25,494	$18,695	$18,647	$484	$62,836	$10,101	$52,734
2017	$7,821	$17,278	$18,763	$704	$43,862	$2,317	$41,545
2018	$7,943	$32,463	$21,998	$516	$62,404	$13,443	$48,962
2019	$14,914	$23,922	$16,413	$533	$55,249	$9,150	$46,100
2020	$2,741	$25,419	$17,975	$512	$46,135	$3,681	$42,454
2021	$2,628	$40,121	$20,344	$496	$63,093	$13,856	$49,237
2022	$16,928	$66,581	$46,671	$527	$130,180	$49,590	$80,590
2023	$8,669	$63,045	$51,494	$518	$123,207	$46,104	$77,104
2024[1]	$6,381	$52,837	$68,257	$865	$125,048	$47,021	$78,027

(1) Information for 2024 is preliminary.

(2) Incremental costs are not included in the Total AOM Savings value.