BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Notice of Incentive Mechanism Workshop ______________________________/	Undocketed Filed: March 23, 2017

CITIZENS' POST WORKSHOP COMMENTS

The Citizens of the State of Florida, through the Office of Public Counsel (OPC), hereby files their comments related to the Incentive Mechanism Staff Workshop. At the workshop held February 9, 2017, Staff presented a power point presentation which put forth a "strawman" for discussion purposes in the review of incentives for Florida Electric Utilities (IOUs). At the close of the workshop, Staff requested that any comments on review of the current IOUs incentives and the strawman suggestions be filed by March 23, 2017.

Citizens retained Dr. David Dismukes to consult on the drafting of comment on the strawman and the current IOU incentives.[1] Attached are OPC's comments regarding the strawman and review of the current incentives. In addition to the current wholesale power sale incentives, OPC discusses the elements of the modified Asset Optimization Mechanism included in the FPL settlement, Tampa Electric Company's Petition for Approval of Energy Transaction Optimization Mechanism and the Generation Performance Incentive Factor (GPIF). OPC notes that these comments are preliminary, and subject to change, based on a full vetting process and additional information becoming available. OPC reserves our right including those of OPC

[1] Dr. David Dismukes has filed testimony on these issues in the consolidated FPL rate case (Dockets Nos. 160021-EI, 160061-EI, 1600062-EI, and 160088-EI) and In Re: Review of the Appropriate Application of Incentives to Wholesale Power Sales by Investor-Owned Electric Utilities (Docket No. 991779-EI).

consultant(s) to change positions regarding the incentive mechanisms if and when additional information becomes or is made available.

s/Patricia A. Christensen
Patricia A. Christensen
Associate Public Counsel

Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, Florida 32399-1400
(850) 488-9330

Attorney for the Citizens
of the State of Florida

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and foregoing Citizens' Post Workshop Comments has been furnished by electronic mail on this 23rd day of March, 2017, to the following:

Matthew R. Bernier Duke Energy Florida. 106 East College Ave, Suite 800 Tallahassee, FL 32301-7740 matthew.bernier@duke-energy.com	Suzanne Brownless/Tom Ballinger/Phillip Ellis Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, FL 32399-0850 sbrownle@psc.state.fl.us tballinger@psc.state.fl.us pellis@psc.state.fl.us
Jon C. Moyle, Jr. Florida Industrial Power Users Group 118 North Gadsden Street Tallahassee, FL 32301 jmoyle@moylelaw.com	Russell Badders Beggs & Lane Law Firm P.O. Box 12950 Pensacola, FL 32591-2950 rab@beggslane.com
	s/Patricia A. Christensen Patricia A. Christensen Associate Public Counsel

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Notice of Incentive Mechanism Workshop ______________________________/	Undocketed Filed: March 23, 2017

Comments of the Office of Public Counsel
Strawman Revisions to the Commission's Incentive Framework

The Office of Public Counsel ("OPC") would like to thank the Florida Public Service Commission ("FPSC" or "Commission") for the opportunity to present comments on Staff's revisions to the Commission's wholesale incentive mechanism.

The OPC was created by the Florida Legislature in 1974 to provide legal representation for Floridians in proceedings before the Commissions. The OPC is dedicated to the principle that the rate-setting function of the Commission is best performed when ratepayers who are ultimately responsible for paying utility rates are represented on a basis comparable to those advocating on behalf of the utility companies operating in Florida. In addressing the review of current and strawman suggestions to consider changes to incentive mechanisms, OPC has engaged Dr. David Dismukes to consult in the drafting of these comments submitted by OPC. OPC notes that these comments are preliminary and limited to responding to the strawman without a full vetting process through discovery. OPC reserves our right including those of OPC consultant(s) to change positions regarding the incentive mechanisms if and when additional information becomes or is made available or to the extent there is a change in law affecting the Commission's authority or role related to incentive mechanisms.

I. Introduction

On February 9, 2017, Staff held an informal workshop to review the Commission's wholesale incentives mechanisms for electric utilities, and to explore potential avenues of improving these mechanisms. Interested parties representing a diverse set of interests participated in the workshop, including, among others, all four of the State's investor-owned electric utilities, the Florida Industrial Power Users Group ("FIPUG"), and the OPC. Discussions at Staff's workshop were spirited, and informative.

Staff began the informal workshop with a "strawman" presentation it had prepared to initiate a dialog among parties. This presentation reviewed three major incentive mechanisms the Commission has at its disposal for regulated electric utilities, including what Staff referred to as the Commission's Wholesale Sales Incentive Mechanism, the Generation Performance Incentive Factor ("GPIF"), and the more recent Asset Optimization Mechanism negotiated as part of recent settlements for Florida Power and Light ("FPL"). Staff also identified the following four characteristics Staff desired in potential incentive mechanisms:

(1) Place Ratepayers First;
(2) Prevent Conflicting Incentives;
(3) Approach Markets Neutrally;
(4) Set Clear Expectations.

With regards to Staff's desire for incentive mechanisms to "place ratepayers first," Staff expressed a desire that (1) reliability be preserved, thus all assets should be used to meet ratepayers' needs first, (2) incentives should maximize net gains for ratepayers' benefits, and (3) incentives should not encourage risky activities that might ultimately result in financial losses. Likewise, with regards to preventing conflicting incentives, Staff expressed a desire that poor performance in one area, such as generator operational performance, subject to incentives should not be rewarded in another area, such as wholesale market transactions, subject to a different incentive. Additionally, Staff stated its belief that incentives should not provide incentives for activities already receiving incentives, nor should they encourage excess assets or reward regulatory requirements. Finally, Staff stated that it desired incentive mechanisms be based on fixed and clearly defined thresholds and targets with limited adjustments, and which include incentivized transactions that are clearly defined.

Pursuant to its desired characteristics for future incentive mechanisms, Staff laid out a strawman outlining four possible changes to the Commission's established framework of incentives for jurisdictional electric utilities. These changes included: (1) the expansion of activities qualifying for incentives under the Commission's orders; (2) the elimination of existing thresholds for non-incentivized wholesale transactions; (3) a decrease in the utility portion and increase in ratepayer sharing percentages from the existing 80-20 ratio to a 95-5 ratio; and (4) the elimination of the GPIF.

To the extent that it is a serious proposal rather than a more likely discussion inspiring catalyst, the strawman appears to be putting the proverbial "cart before the horse." Although Staff in developing its strawman appears to have put much thought into the characteristics and objectives of an optimal incentive regime, and the objectives it should achieve, the strawman does not first address in exactly what ways the Commission's existing policies are deficient. While recognizing that Staff's suggestions are only a strawman proposition, we note that several essential analyses have yet to be undertaken or completed. Importantly, the posited revisions to the Commission's incentive mechanisms could trigger both social and economic impacts, neither of which has been analyzed or assessed.

Furthermore, Staff's understandably limited presentation includes statements that have no empirical or tangible analysis to support them. For example, in framing the strawman, Staff asserts that an optimal incentive mechanism should not encourage activities that might result in financial losses. Likewise, Staff asserts that an optimal incentive mechanism should not "encourage excess assets," which OPC interprets as meaning encouraging excess capacity and over-capitalization. OPC agrees that the Commission's incentive policies should not encourage risk-seeking behavior on the part of the utilities, or encourage over-development of utility systems. However, the strawman does not first address whether the Commission's current state-wide incentive policies (Wholesale Sales Incentive Mechanism and GPIF) encourage risky investments on the part of utilities, or encourage the development of excess capacity.

Indeed, these gaps are representative of another possible shortcoming with the strawman. Staff's presentation did not identify in what manners it believes the Commission's existing policies are deficient. The strawman appears to assume as a given -- and with no supporting analysis -- that the Commission's existing statewide policies are seriously flawed and in need of major reforms. Yet, the Commission's policies, with the exception of FPL's potentially flawed Asset Optimization Mechanism,[1] have been in effect for decades and have operated with little serious controversy. OPC respectfully posits that the suggestions included within the strawman are premature without necessary evidentiary support to justify their implementation.

In the alternative, OPC recommends the Commission retain its existing wholesale sales incentive mechanism without modifications, allowing the Asset Optimization Mechanism in place for FPL to lapse at the end of the term of the existing settlement agreement. OPC additionally recommends the Commission improve the operations of the GPIF by removing the existing allowance for adjustments of historic operation metrics under the GPIF rules. Furthermore, the Commission should examine the potential to change the manner in which the Commission

[1] OPC acknowledges that FPL's Asset Optimization Mechanism was included as part of a negotiated comprehensive, global settlement to which OPC was a signatory.

determines individual generator operation performance targets under the GPIF to incorporate a process that places generator performance against that of like-situated facilities elsewhere in Florida and across the country.

II. Incentive Program Historic Overview

(a) Wholesale Sales Incentive Mechanism

The Commission's original off-system sales incentive policies date back several decades to the time of the energy crisis of the early 1980s. During this time period, energy costs were high, and there were emerging questions about generator availability, generator efficiency, and the various primary fuels used to generate electricity. This was the period in which Florida began adopting policies encouraging both demand- and supply-side efficiencies, as well as fuel diversity. Previously, off-system sales revenues were credited to base rates and were not part of the fuel adjustment clause proceedings.

In 1984, the Commission established an incentive program to encourage electric IOUs to participate more actively in what was known as the Florida Energy Broker Network ("broker network").[2] Under the broker system, utility generators would "trade" excess generation on a cost basis, where the "gains" on sale would be determined as the relative differences of the cost of generation being displaced by the broker sales. The Commission eventually decided to allow utilities to share in the gains on sales made into the broker network. The incentives were structured such that utilities and their shareholders would receive 20 percent of all gains made on these relatively limited, off-system "opportunity sales," whereas ratepayers would receive, as credits through their fuel charge, the remaining 80 percent of those gains.[3]

[2] In re: Fuel Adjustment Recovery Clauses of Electric Utilities – Treatment of Gain on Economy Sales, Order No. 12923, issued January 24, 1984, in Docket No. 830001-EU-B.
[3] In re: Fuel Adjustment Recovery Clauses of Electric Utilities – Treatment of Gain on Economy Sales, Order No. 12923, issued January 24, 1984, in Docket No. 830001-EU-B.

At the time, incentives were thought to be needed for a variety of reasons. First, off-system sales, as a general matter, arose very infrequently. Wholesale markets, as we know them today, did not exist. To the extent that a wholesale "market" could be said to exist, this market was limited to longer-term, multi-year transactions between utilities, and not short term commodity transactions which occur frequently in today's wholesale electricity market. Thus, creating an incentive to encourage utilities to participate in what was becoming a platform for short-term sales transactions seemed important. Second, utilities at that time did not dedicate considerable dispatch and operational resources to facilitate these kinds of short-term transactions, so an incentive was determined to be important to encourage utilities to make the appropriate investments and incur certain costs which were needed to participate in the emerging broker system. Lastly the early 1980s reflected a period of higher wholesale prices, and an incentive was deemed appropriate to facilitate greater supply-side efficiencies that would benefit both utilities and ratepayers.[4]

In 1999, the Commission decided to revisit its off-system sales incentive policies given the dramatic changes that were arising in the industry during this time period. Specifically, the Energy Policy Act of 1992 included provisions that began the process of opening wholesale markets to competition. In the mid-1990s, the FERC promulgated rules (Order Nos. 888[5] and 889[6]) defining the framework in which wholesale competition would be conducted. This was the same time period in which independent power producers ("IPPs"), or "merchant power providers," started to construct for-profit generation facilities, including several in Florida. For most utilities,

[4] In re: Fuel Adjustment Recovery Clauses of Electric Utilities – Treatment of Gain on Economy Sales, Order No. 12923, issued January 24, 1984, in Docket No. 830001-EU-B.
[5] Order No. 888. U.S. Federal Energy Regulatory Commission. Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Docket No. RM95-8-000 and Recovery of Stranded Costs by Public Utilities and Transmitting Assets, Docket No. RM94-7-001, issued April 24, 1996. 75 FERC 61,080.
[6] Order No. 889. U.S. Federal Energy Regulatory Commission. Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct. Docket No. RM95-9-000, issued April 24, 1996. 75 FERC 61,078.

transactions in wholesale markets became an important part of their overall operations. In fact, many Florida utilities during this time period independently shifted their off-system sales activities away from the cost-based broker system and towards the market-priced competitive wholesale market with greater potentials for off-system sales gains. These changes convinced the Commission that it needed to revisit its incentive policies.

The Commission made several changes to its incentive policies during this time period. The first change was to clarify that any off-system sales incentives would apply to all non-separated,[7] non-emergency wholesale transactions and not just those on the broker system.[8] The second change was that, while the Commission maintained the 80 percent/20 percent sharing ratio between ratepayers and shareholders, respectively, the Commission set a sharing threshold for each jurisdictional investor-owned utility ("IOU") based on a three-year moving average of gains in wholesale markets. The Commission adopted this policy explicitly as a ratepayer protection to ensure that utilities were not granted incentive rewards for activities that would have presumably been undertaken in the absence of the incentive mechanism.[9] Thus, 100 percent of any gains from off-system sales below this threshold level would accrue to ratepayers.

(b) Generation Performance Incentive Factor ("GPIF")

In 1980, the Commission instituted the Generation Performance Incentive Factor ("GPIF") as a financial incentive and penalty framework that would encourage the investor-owned electric utilities to "operate their generating units as efficiently as possible and minimize fuel costs borne

[7] Non-separated wholesale energy sales are either non-firm or less than one year in duration. The assets used to make such sales are not separated from the utility's retail rate base.

[8] The Commission clarified this policy since it found that it was being applied inconsistently across utilities. FPL, FPC (Duke Energy Florida), and TECO, for instance, applied the incentive to broker system sales only whereas Gulf Power applied the incentive to all off-system energy sales.

[9] <u>In Re: Review of the Appropriate Application of Incentives To Wholesale Power Sales by Investor-Owned Electric Utilities</u>, Order No. PSC-00-1744-PAA-EI, issued September 26, 2000 in Docket No. 991779-EI, at pp 10-11.

by their customers."[10] Under the GPIF, the Commission sets individual annual performance targets for each IOU base load unit. These performance targets are based upon each unit's historic equivalent availability factor ("EAF") and average heat rate. These metrics were chosen by the Commission because increased availability and thermal efficiencies lead directly to utility fuel costs, and thus reduced costs to ratepayers through lower fuel clause charges.

(c) FPL Asset Optimization Mechanism

In 2013, a single paragraph was included in the incentive mechanism program for FPL as part of a larger, global settlement agreement reached among several parties in that company's rate case.[11] This settlement changed the operations of the incentive mechanism for FPL significantly and expanded the types of transactions upon which FPL could receive financial incentives. The new, modified, incentive program (hereafter referred to as the "Asset Optimization Mechanism") was defined for a four-year period, and included at least five different types of transactions, originating from several utility assets, not just power generation. These transactions, and their supporting assets, included:

1) Gas storage utilization: Release contracted natural gas storage or sell stored natural gas.

2) Delivered city-gate gas sales using existing transport: Sales of natural gas to Florida customers combined with FPL's existing gas transportation capacity.

3) Production (upstream) area sales: Sales of natural gas in the production areas combined with FPL's existing gas transportation capacity.

4) Release of natural gas pipeline capacity and electric transmission capacity: Sales of idle natural gas transportation and/or electric transmission capacity.

[10] In re: Investigation of Fuel Cost Recovery Clause Application to Investor-owned Electric Utilities, Order No. 9558, issued September 19, 1980, in Docket No. 800400-CI, p 1.
[11] In re: Petition for Increase in Rates by Florida Power & Light Company, Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 120015-EI, at pp. 13-15.

5) Asset Management Agreement: Outsourcing of optimization functions to a third party through assignment of transportation and/or storage rights in exchange for a premium paid to FPL.[12]

The FPL asset management incentive is unique since prior to its adoption, the Commission only recognized gains on off-system sales for incentives, not gains from off-system purchases.[13] In addition, the new FPL Asset Optimization Mechanism program utilized thresholds and sharing percentages that were modified from the Commission's prior incentive program. For instance, the new FPL asset management incentive set a $46 million threshold.[14] This $46 million threshold was based upon two components that included: (1) a $36 million "customer savings threshold," purportedly based on FPL's 2013 projections for wholesale economy energy sales gains and wholesale economy energy purchases savings, and (2) an incremental $10 million threshold amount that represented the additional gains FPL anticipated from its other assets.[15] Any gains on sales below this $46 million threshold were credited to ratepayers as a reduction to fuel costs recovered through the Fuel and Purchased Power Cost Recovery Clause ("fuel clause").

Any gains on off-system sales above $46 million were shared between FPL and ratepayers such that:

- FPL retained 60 percent and ratepayers received 40 percent of gains between $46 million and $100 million;
- FPL retained 50 percent and ratepayers received 50 percent of the gains above $100 million.

---

[12] In re: Petition for Increase in Rates by Florida Power & Light Company, Order No. PSC-13-0023-S-EI, in Docket No. 120015-EI, issued January 14, 2013, Attachment A, in Docket No. 120015-EI, at pp.13-1422-23.
[13] In re: Petition for Increase in Rates by Florida Power and Light Company, Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 120015-EI, pp. 4-6.
[14] In this context, "gains" shall refer to the sum of the following: 1) the difference between incremental revenue and incremental cost of wholesale economy energy sales and eligible asset optimization transactions; and 2) the difference between the transaction price for FPL's wholesale economy energy purchases and its incremental costs if FPL had met that retail load with its own resources.
[15] In re: Petition for Increase in Rates by Florida Power & Light Company, Docket No. 120015-EI, Direct Testimony of FPL witness Sam A. Forrest (October 12, 2012), pp. 5-6.

Moreover, the Asset Optimization Mechanism also allowed the Company to recover, through the fuel clause, any incremental operations and maintenance ("O&M") costs incurred in facilitating off-system sales or purchases. These O&M costs include the incremental personnel, software and associated hardware costs incurred by the Company not included in its 2013 test year. The modified incentive program also allowed FPL to recover all variable power plant O&M costs (non-fuel O&M expenses and costs for capital replacement parts that vary as a function of a power plant's output) that are incurred by the Company to generate additional output in order to make wholesale economy energy sales. At the time, the Company estimated that any variable power plant O&M costs for generation above 514,000 megawatt-hours ("MWh") would be eligible for cost recovery under these provisions.[16]

FPL's Asset Optimization Mechanism was renewed as part of the global settlement in its last rate case (Docket Number 160021-EI). The Commission, however, made the following modifications to the incentive mechanism that included:

- The sharing threshold for FPL was reduced from $46 million to $40 million,
- Unlike its 2013 test year, FPL did not estimate the amount of wholesale economy energy sales in its 2016 test year filing. Therefore, the 514,000 MWh threshold on economy sales authorized by Order No. PSC-13-0023-S-EI was removed.
- Instead, FPL netted the amount of wholesale economy sales and purchases each year to determine the impact of variable power plant operation and maintenance expenses at a rate of $.065/MWH. If sales were greater than purchases, then FPL would recover the net amount from customers at $.065/MWH. If purchases were greater than sales, customers would receive a credit for the net variable power plant operation and maintenance expenses saved at the same rate.
- With these modifications, the pilot Incentive Mechanism was extended to December 31, 2020.

[16] In re: Petition for Increase in Rates by Florida Power & Light Company, Docket No. 120015-EI, Direct Testimony of FPL witness Sam A. Forrest (October 12, 2012), p. 21.

On January 23, 2013, Tampa Electric Company ("TECO") filed a petition for expedited approval of its own Asset Optimization Mechanism in Docket Number 130024-EI.[17] In its petition, TECO referenced the settlement agreement determination that included, in part, the creation of FPL's Asset Optimization Mechanism in late 2012, specifically noting that its proposal was "very similar."[18] TECO's proposal would have allowed the company to include for incentives any gains on short-term wholesale sales and purchases, and six other forms of asset optimization the company undertook.[19] Separate from its proposal to expand eligible incentive activities, TECO's proposal also lowered ratepayers' sharing percentage of gains.[20]

On May 30, 2013, TECO filed a motion to hold the issue of approval of its Asset Optimization Mechanism in abeyance,[21] withdrawing its proposal entirely later that year. However, on June 30, 2016, TECO filed a new petition with the Commission for an Asset Optimization Mechanism (this time referred to as the Energy Transaction Optimization Mechanism).[22] TECO's new requested incentive mechanism is virtually identical to its early request, with the exception of updated thresholds based on actual economy sales and purchases for the prior four years, and a provision preventing cost recovery for incremental costs to implement

---

[17] In Re: Tampa Electric Company's Petition for Expedited Approval of Asset Optimization Incentive Mechanism, Docket No. 130024-EI, Tampa Electric Company's Petition for Expedited Approval of Asset Optimization Incentive Mechanism.

[18] In Re: Tampa Electric Company's Petition for Expedited Approval of Asset Optimization Incentive Mechanism, Docket No. 130024-EI, Tampa Electric Company's Petition for Expedited Approval of Asset Optimization Incentive Mechanism, p. 2.

[19] In Re: Tampa Electric Company's Petition for Expedited Approval of Asset Optimization Incentive Mechanism, Docket No. 130024-EI, Tampa Electric Company's Petition for Expedited Approval of Asset Optimization Incentive Mechanism, pp. 3-4.

[20] In Re: Tampa Electric Company's Petition for Expedited Approval of Asset Optimization Incentive Mechanism, Docket No. 130024-EI, Tampa Electric Company's Petition for Expedited Approval of Asset Optimization Incentive Mechanism, p. 5.

[21] In Re: Tampa Electric Company's Petition for Expedited Approval of Asset Optimization Incentive Mechanism, Docket No. 130024-EI, Order Granting Tampa Electric Company's Motion to Hold Petition in Abeyance, Order No. PSC-13-0295-PCO-EI.

[22] In Re: Tampa Electric Company's Petition for Approval of Energy Transaction Optimization Mechanism, Docket No. 16-0160-EI, Tampa Electric Company's Petition for Approval of Energy Transaction Mechanism.

the mechanism.[23] On December 20, 2016, TECO filed a motion to defer consideration of its proposal, noting that Staff had indicated a desire to conduct the generic workshop preceding these comments. As such, TECO requested its mechanism be considered in light of any revisions made subsequent to the outcomes of the current generic workshop.[24]

III. Strawman

The first element of the Commission staff's strawman framework is to expand qualifying activities to include the sale and purchase of short-term, non-emergency generation and transmission services as well as fuel activities, including transportation and acquisition. In short, it would appear that the Staff's strawman would expand qualifying activities to include transactions that are currently only allowed incentive treatment for FPL pursuant to its rate case settlement agreements. These transactions, and their supporting activities, are comparable to those associated with the current FPL Asset Optimization Mechanism and include gas storage utilization, in-state natural gas sales, production area natural gas sales, pipeline capacity release and power transmission capacity sales, and other asset management activities.

OPC recognizes that the list of eligible activities included in the strawman is the same as the one currently included in the FPL Asset Optimization Mechanism. However, the fact that these activities are part of the FPL incentive mechanism should not make them relevant for other IOUs given the unique nature in which both of FPL's prior Asset Optimization Mechanisms have been approved. It should be recognized that both plans were approved as part of negotiated settlement agreements in prior rate cases, and, as such, there is no precedent from the Commission that on a stand-alone basis the Asset Optimization Mechanism is in the public interest. Settlements, by their

---

[23] In Re: Tampa Electric Company's Petition for Approval of Energy Transaction Optimization Mechanism, Docket No. 16-0160-EI, Tampa Electric Company's Petition for Approval of Energy Transaction Mechanism, ¶9.
[24] In Re: Tampa Electric Company's Petition for Approval of Energy Transaction Optimization Mechanism, Docket No. 16-0160-EI, Letter from James D. Beasley dated December 20, 2016.

very nature, include individual provisions that lead to individual party benefits that may not necessarily be favorable to other parties or to parties as a whole (i.e. the public interest).

Furthermore, OPC believes that expanding the set of eligible activities, in a fashion contained in the strawman, will compromise the stated policy goal of prioritizing ratepayers' interests over the utilities' interests for a number of reasons that include incentivizing utilities to over-capitalize, subsidizing forays into competitive markets, and disrupting established risk-reward relationships for construction of generation units.

(a) The strawman would increase utility over-capitalization incentives

OPC is concerned that the strawman, much like FPL's Asset Optimization Mechanism, would create incentives for utility over-capitalization since it would expand the scope of the utilities' market from just serving their jurisdictional retail loads to one that could allow utilities to leverage overwhelmingly ratepayer-supported resources to compete for disproportionate shareholder benefit in a broader set of energy markets. The expansion of this market scope would likely create incentives, particularly at the margin, for utilities to secure greater levels of wholesale power and natural gas capacity than they otherwise would. This additional capacity would provide additional resources to expand the utilities' ability to earn incentive returns. The greater the capacity, the greater the leverage a utility would have to make power and natural gas off-system sales.

In fact, the reported benefits associated with FPL's modified incentive program for the 2009-2011 period were considerably lower than those reported in the prior three years. For instance, FPL reported wholesale energy sales gains of $20.0 million and wholesale energy purchase savings of $182.7 million, or a combined $202.8 million during the 2009-2011 time period.[25] The average annual combined wholesale gains and purchase savings level for the time period 2009-2011 was reported as $67.6 million, a level that is nearly twice as much as the Company's actual combined gains/savings performance under the modified incentive program (2013-2015) of $36.1 million. Thus, it is difficult to argue that the strawman, which would be comparable in nature to the prior and current FPL Asset Optimization Mechanism, would result in any meaningful improvement to the financial performance of any IOU's off-system sales and purchase activities. In fact, the prior FPL experience suggests that FPL's ratepayers were likely better off under the 2009-2011 incentive regime[26] since, during that time period, they received over $202.8 million in off-system activities, whereas under the modified incentive program, ratepayers have received only $102.2 million. FPL claimed that this reduction in off-system gains is due to a weakening market providing less opportunities to engage in wholesale sales;[27] however, the fact remains that ratepayers have received less economic gains under the FPL Asset Optimization Mechanism then prior to the mechanism's implementation.

(b) The strawman would be inconsistent with the stated guiding principle for market neutrality

In addition to the overcapitalization incentive, the strawman would encourage the utilities to compete in competitive power and gas markets with energy capacity assets that are funded by their retail ratepayers. This feature directly conflicts with the stated policy goal of designing an

[25] FPL Schedules A6 and A9 filed in Docket Nos. 100001-EI (January 2010), 110001-EI (January 2011), and 120001-EI (January 2012). See, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor; Docket No. 100001-EI, Document No. 00491-10, dated January 19, 2010, Schedule A6 and A9, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor; Docket No. 110001-EI, Document No. 00473-11, dated January 19, 2011, Schedule A6 and A9; In re: Fuel and purchased power cost recovery clause with generating performance incentive factor, Docket No. 120001-EI, Document No. 00391-12, dated January 20, 2012, Schedule A6 and A9.
[26] The Commission's current off-system sales incentive that exist for the other three IOUs as set forth by Order No. PSC-00-1744-PAA-EI, issued September 26, 2000, in Docket No. 991779-EI.
[27] In Re: Petition for Increase in Rates by Florida Power & Light Company, Docket No. 160021-EI, Rebuttal Testimony of Sam A. Forrest, 7:1-4.

incentive mechanism that approaches "markets neutrally." The strawman would allow utilities to effectively securitize a wide range of energy capacity under regulated retail rates and then use that capacity, strategically, when market opportunities arise. Other competitive wholesale energy market participants are not afforded similar benefits.

Each of the State's utilities currently makes a number of investments in power generation and transmission facilities in order to serve that utility's individual load. In doing so, utilities make a number of longer-term natural gas commodity, transportation, and storage investments. Expanding the scope of eligible activities effectively expands the scope of the utilities' market activities from just serving jurisdictional retail load, to one that allows the use of ratepayer-supported resources to compete in broader energy markets. This creates incentives to secure greater levels of wholesale power and natural gas capacity than is required for a utility's own operations since the additional capacity provides the utility with additional resources needed for expanded opportunities to earn incentive returns.

(c) The strawman would not appropriately balance market risks between ratepayers and the utility.

In addition, the strawman turns prior regulatory risk-reward relationships on their head. Consider that the Commission originally approved fuel cost recovery clauses proceedings on the simple premise of dollar-for-dollar cost recovery of eligible fuel costs, fuel-related costs, and purchased power costs.[28] For over 40 years, utilities have been reimbursed on a dollar-for-dollar basis for the billions of dollars that flow through the fuel clause each year. Thus, to provide a shareholder incentive on the savings from a wholesale economy energy purchase as well as

[28] In re: General Investigation of Fuel Adjustment Clauses of Electric Companies, Order No. 6357, Docket No. 74680-CI, issued November 26, 1974. In re: General Investigation of Fuel Adjustment Clauses of Electric Companies, Order No. 7653, Docket No. 74680-CI (CR), issued February 22, 1977.

reimbursing the utility for the cost of the purchased power would violate this longstanding bedrock principle of only dollar for dollar recovery and skews the risk-reward relationship.

When a utility chooses to buy economy energy at a price less than what it would cost to generate an equivalent amount of energy with its next available resource, this dynamic creates benefits for both of the utilities' power plant operational efficiencies, utilities and ratepayers. For the selling utility, this wholesale transaction allows the less expensive generation unit to provide electricity to the grid instead of being offline. This unit operates more efficiently for a longer service life with fewer startups and shutdowns. As this unit consumes more fuel, the selling utility may negotiate a more favorable delivered fuel prices which creates a virtuous cycle for this unit. The buying utility conserves the fuel and reduces the corresponding emissions from the more expensive unit that otherwise would have operated in the absence of the wholesale transaction. Although offline, this unit is available to serve retail load at a later time should the need exist. Overall, this scenario is a win-win for both utilities, their ratepayers, and the public interest – retail load is served; more efficient resources are dispatched ahead of less efficient resources; less fuel is consumed; and fewer pollutants emitted. Importantly, these incentives are inherent in market operations, meaning that the strawman's suggestion to expand qualifying activities to include gains on economic purchases would be merely incentivizing activities already in the utility's best interest.

The strawman's inclusion of gains on economic purchases would be inconsistent with the goal of prioritizing ratepayer interests and would be contrary to past Commission precedent and the regulatory policies of just about every state that regulates a vertically-integrated utility. Consider that, with the exception of FPL, the other three Florida IOUs currently allocate 100 percent of the savings from wholesale energy purchases (i.e., compared with the cost to generate the equivalent amount of energy) to their ratepayers. This component of the strawman appears to run counter to the *quid pro quo* associated with the development of the Commission's fuel and purchased power cost recovery policies.

When the Commission adopted its fuel and purchased power cost recovery mechanisms, it did so in order to insulate utilities from the risk of large, volatile, and often uncontrollable commodity prices.[29] In return, utilities are expected to secure the optimum least-cost, reliable resources on the behalf of their ratepayers, regardless of whether those resources are self-generated or come from the market. The strawman upsets the balance between ratepayers' assumption of commodity pricing risk, and undermines the utilities' obligation to ensure they purchase or utilize the most cost-effective resources available. The utilities are not only insulated from commodity pricing risk, but would receive an incentive for engaging in activities that they should be doing as part of its obligation to serve and doing as part of its *quid pro quo* for having a fuel and purchased power recovery mechanism.

Rate regulation in markets dominated by natural monopolies is intended to be a proxy for competition in those markets. Firms in competitive markets tend to produce at their lowest cost in order to improve market share and secure their profits. If a competitive firm has a choice between internalizing a particular function or outsourcing that function to another firm, theory and practice suggests that competitive firms will chose the least cost option. The firm needs no additional incentive to choose a lower cost provider of a service outside the normal rate of return it earns in the market.

---

[29] In re: General Investigation of Fuel Adjustment Clauses of Electric Companies, Order No. 6357, issued November 26, 1974, in Docket No. 74680-CI. In re: General Investigation of Fuel Adjustment Clauses of Electric Companies, Order No. 7653, issued February 22, 1977, in Docket No. 74680-CI (CR).

The same should be true for a utility if regulation is emulating competition. Utilities should need no additional incentive to provide least-cost service outside of their allowed rate of return. To do otherwise suggests either (a) the utility is not afforded a reasonable allowed rate of return or (b) regulation is not emulating competition and free markets. In fact, the Commission, in its 2010 Annual Ten Year Site Plan review noted that electric utilities "(...) <u>must</u> continue to explore <u>all available measures</u> to ensure the most efficient means of producing and delivering reliable and affordable power to their customers."[30] Finally, the utilities have interpreted this efficiency requirement as requiring cost-effectiveness.

(d) The strawman would eliminate existing thresholds that apply discipline to utility operations.

The proposed strawman additionally suggests eliminating the incentive thresholds that have been utilized by the Commission since the late 1990s to ensure that utility financial incentives are actions that are over and beyond what should be expected of prudent utility actions. The strawman suggests this on the basis that the existing incentive mechanisms unfairly punish utilities for market conditions that are outside of their control. OPC disagrees with the strawman since: (1) the proposal suggestions would be inconsistent with the principle of prioritizing ratepayer interests; (2) the suggestions would eliminate a disciplining factor associated with the existing mechanism that can help to reduce utility incentives for over-capitalization by ensuring that they do not make extra profits by simply having spare capacity in place when a market opportunity arises; and (3) exposing utilities to some form of market risk is consistent with an appropriately designed incentive mechanism by requiring utilities to bear at least some market risk for utilizing "spare" capacity for market gains.

---

[30] FPSC *Review of 2010 Ten-Year Site Plans for Florida's Electric Utilities*, at p 2, emphasis added.

The strawman would also ignore the important ratepayer protections that the Commission's existing thresholds incorporate into the wholesale incentive mechanism. In Order No. PSC-00-1744-PAA-EI, the Commission established the current three-year moving average used to benchmark an appropriate level of sales eligible for incentives through the Commission's wholesale incentive mechanism.[31] In adopting this threshold, the Commission was explicit in its desire to limit eligible sales to only those occurring due to the presence of the mechanism, and not those that would be occurring in the absence of the mechanism.[32]

> In establishing an appropriate incentive structure, we believe that the incentive should not be designed to encourage behavior that is already occurring. Therefore, the incentive should be based on some type of threshold that represents the level of sales that would be expected to occur in the absence of an incentive. This threshold should be determined using past data on the gains on non-separated wholesale sales eligible for the incentive. As OPC witness Dismukes testified, any incentive provided for gains below this threshold will create the potential for a free rider effect, rewarding utilities for behavior which is taking place for reasons other than the incentive.[33]

In addition, the Commission's existing thresholds strongly weaken a utility's incentive to overcapitalize. It accomplishes this by benchmarking utility eligible sales to historic averages, specifically a three-year moving average. A utility that possesses a dearth of spare generation capacity will not be able to utilize such capacity to what amounts to ratepayer-financed merchant generators seeking wholesale sales opportunities since continued levels of off-system sales will be incorporated into the utility's three-year moving average threshold. Thus, the Commission's

[31] In re: Review of the appropriate application of incentives to wholesale power sales by investor-owned electric utilities. Docket No. 991779-EI, Order No. PSC-00-1744-PAA-EI, issued September 26, 2000.
[32] In re: Review of the appropriate application of incentives to wholesale power sales by investor-owned electric utilities. Docket No. 991779-EI, Order No. PSC-00-1744-PAA-EI, issued September 26, 2000, pp. 10-11.
[33] In re: Review of the appropriate application of incentives to wholesale power sales by investor-owned electric utilities. Docket No. 991779-EI, Order No. PSC-00-1744-PAA-EI, issued September 26, 2000, pp. 9-10-11.

existing thresholds incentivize wholesale market transactions, while dis-incentivizing overcapitalization.

Finally, in suggesting removing the existing incentive mechanism, the strawman appears to assume that the existing mechanism does not appropriately balance market risks between a utility's ratepayers and its shareholders. The strawman would eliminate the three-year moving average for non-separated wholesale energy sales before a utility's shareholders receive 20 percent of the gains on sales above this threshold. Underlying this suggestion is the flawed notion that the current wholesale sharing incentive treats utilities unfairly for operational conditions outside of its control, such as the weather. However, this concern was directly addressed by the Commission in its Order No. PSC-00-1744-PAA-EI, and is the reason the existing thresholds are based on a three-year moving average rather than an administratively set amount.[34] As previously noted by the Commission, the use of a moving average reduces the impact of anomalies in wholesale market opportunities in any year. Any remaining variations can be reasonably expected to average out over the long-term.

> The evidence indicates that the yearly gains on these sales may be erratic due to changes in capacity, or other factors beyond a seller's control, such as the needs of buyers. We agree with OPC witness Dismukes that it is appropriate to use a moving average to determine the threshold to reduce the impact of anomalies in individual years. We find that a three year moving average is appropriate (...).[35]

---

[34] In re: Review of the appropriate application of incentives to wholesale power sales by investor-owned electric utilities, Docket No. 991779-EI, Order No. PSC-00-1744-PAA-EI, issued September 26, 2000, p. 11.

[35] In re: Review of the appropriate application of incentives to wholesale power sales by investor-owned electric utilities, Docket No. 991779-EI, Order No. PSC-00-1744-PAA-EI, issued September 26, 2000, p. 1110.

(e) The strawman would incorrectly modify existing incentive sharing percentages.

The strawman suggests a significant modification in the current incentive mechanism's sharing percentages between utility shareholders and ratepayers. The strawman posits allocating 95 percent of the gains on sale from eligible assets to ratepayers with the balance accruing to ratepayers. This potentially represents a significant decrease from the 80 percent ratepayer, 20 percent utility that is currently in place; remembering that the margin sharing under the current incentive mechanism does not kick in until a minimum level of incentive savings have been reached. In fact, elimination of the minimum threshold would appear to be the *quid pro quo* for the suggested sharing percentages proposal.

As the Commission found in Order No. PSC-00-1744-PAA-EI, there is no "magic number" for an appropriate incentive level.[36] However, it appears the strawman suggestion is driven by a suggestion to increase eligible activities allowed under the Commission's incentive policy and to remove the Commission's existing threshold levels. Since the OPC recommends that these suggestions should either not be adopted or otherwise allowed to lapse upon termination of the current FPL settlement, OPC holds that there is little reason to adjust the Commission's sharing ratios.

IV. Modification of the Generating Performance Incentive Factor

The strawman, if adopted, would eliminate the GPIF based upon the presumption that the mechanism leads to a number of conflicting incentives. The first argument is that utilities already have appropriate incentives to maintain efficient generation and that it is unnecessary to maintain the GPIF-based incentive along-side an incentive for off-system sales, or in this case, along-side

[36] In re: Review of the appropriate application of incentives to wholesale power sales by investor-owned electric utilities, Docket No. 991779-EI, Order No. PSC-00-1744-PAA-EI, issued September 26, 2000, p. 9.

the strawman's suggested asset management incentives. The second argument is that current GPIF penalties could be offset by gains on off-system sales (included as part of its suggested asset management plan) thereby undermining the GPIF's effectiveness. In other words, the GPIF will "negatively" incent utilities to increase electricity sales.

First, OPC notes that, if the Commission were to be forced to choose between two competing incentives, it should maintain the GPIF and eliminate the other components of any suggested asset management plan. Utilities have control over generation availability rates and thermal efficiencies, not gains on market sales or market purchases. Granted, the GPIF could benefit from some design improvements, particularly as they relate to the mechanism's transparency and benchmarking provisions. For instance, it would be more useful to benchmark Florida IOU performance to each other, or some form of industry best practices, rather than the utility's own specific historical averages. Further, the Staff could examine the possibility of removing or limiting the application of confusing generator "adjustments" to actual achieved operating statistics. Such adjustments would be far more productive, and place incentives on performance trends that utilities can influence such as their generator availability and thermal efficiencies.

OPC's witness testified before the Commission in the hearing for Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI, regarding the efficacy of a single, transparent, yet effective, efficiency measure to base an incentive return upon.

> The broad goal for an electric utility should be one that encourages it to maximize its capacity utilization and its thermal efficiencies. Capacity utilizations are usually measured by capacity utilization rates. Thermal efficiencies are typically measured by unit and/or system-average heat rates, defined as the thermal inputs utilized to generate one kilowatt-hour ("kWh) of electricity. In fact, the Commission already has an incentive that is tied to both measures in the Generation Performance Incentive Factor ("GPIF"). The

> Commission originally adopted this measure in order to tie incentives to known and measureable performance that is within a utility's operational control. Measures such as market gains on sales are means to greater efficiency and while this is an important statistic for ratemaking purposes, it is not, in and off itself, an efficiency measure. The Commission may find that the use of one single, transparent, yet effective efficiency measure upon which to base an incentive return is more meaningful and effective than a compilation of other factors that have several complicated market and ratemaking implications.[37]

To the extent that the strawman suggests that increased efficiency and availability of GPIF participating units may "negatively" incent utilities to increase wholesale electricity sales, this suggestion does not appear to be supported. The strawman does not provide any specific examples or empirical evidence that the GPIF as currently implemented has resulted in "negative outcomes" and thus necessitating the elimination of the GPIF. Table 1 presents historic Net Energy for Load ("NEL") for three of the four investor-owned utilities. Table 1 shows that the utilities have experienced minimal NEL growth over the past 10 years, with Gulf Power actually experiencing a decline in system NEL over the past 10 years. Both Duke and FPL have seen average NEL growth over the 10 year period that was slightly above and below 1.0 percent, respectively.

[37] In re: Investigation of Fuel Cost Recovery Clause Application to Investor-owned Electric Utilities, Order No. 9558, issued September 19, 1980, in Docket No. 800400-CI, as referenced at the hearing before the Florida Public Service Commission in Docket No. 160021-EI, Petition for Rate Increase by Florida Power & Light Company. Docket No. 160061-EI, Petition for Approval of 2016-2018 Storm Hardening Plan by Florida Power & Light Company. Docket No. 160062-EI, 2016 Depreciation and Dismantlement Study by Florida Power & Light Company. Docket No. 160088-EI, Petition for Limited Proceeding to Modify and Continue Incentive Mechanism by Florida Power & Light Company. August 29, 2016, p. 3329.

Year	Florida Power and Light	Gulf Power	Duke Energy Florida
	------------------	(GWh)	------------------
2006	113,137	12,586	23,182
2007	114,315	12,671	24,010
2008	111,004	12,617	24,738
2009	111,303	11,975	24,993
2010	114,475	12,518	25,212
2011	112,454	12,086	25,228
2012	110,866	11,598	25,480
2013	111,655	11,552	25,759
2014	115,968	12,052	25,800
2015	122,756	11,996	25,866
Ten-Year Growth:	9,619	-590	2,684
Growth Rate:	0.85%	-0.47%	1.16%

Table 1: Historic Net Energy for Load (2006-2015)

Figure 1 below presents historic use per customer for the 10 year period, 2006 through 2015. As this figure shows, two of the three investor-owned utilities, FPL and Gulf Power, generally saw declining use per customer. Gulf Power has seen consistent declining usage trends over that period. Likewise, FPL's usage per customer shows a decline from 2006 to 2014, and only reached its previous 2006 use per customer levels in 2015. Only Duke has seen increased levels of use per customer; yet even for Duke, these trends have leveled off since 2008 at levels only 5 to 8 percent greater than 2006 levels. In both terms of overall and per customer energy sales, it does not appear that the GPIF has had the effect of causing the State's investor-owned utilities to seek greater wholesale sales.

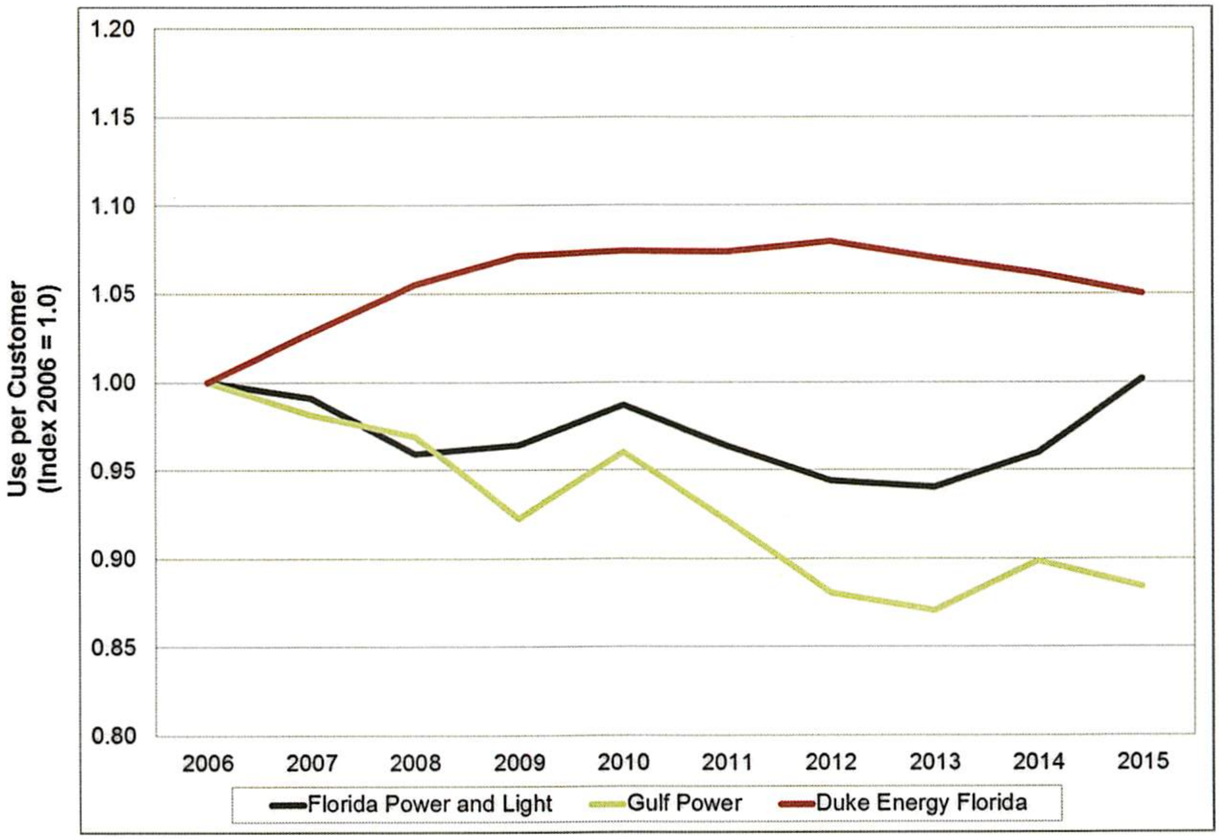

Figure 1: Historic Use per Customer (2006-2015)

This is not to say that the GPIF cannot be improved. As noted earlier, the GPIF was instituted by the Commission in 1980 as a means to encourage IOUs to "operate their generating units as efficiently as possible and minimize fuel costs borne by their customers."[38] On an annual basis, the Commission sets targets and ranges for each electric IOU's base load unit's operating performance based on the unit's "equivalent availability factor" ("EAF") and average heat rate. In this, the GPIF attempts to calculate the savings (or costs) incurred by better- or worse-than-expected performance. Under the GPIF, these savings/costs are shared between the utility's shareholders and ratepayers, and capped at an amount equal to 25 basis points of the utility's common equity.

---

[38] In re: Investigation of Fuel Cost Recovery Clause Application to Investor-owned Electric Utilities, Order No. 9558, issued September 19, 1980, in Docket No. 800400-CI, p 1.

The GPIF, at least in theory, also incentivizes utilities to maintain superior operating statistics in a unique fashion. While other incentive mechanisms, like the Commission's existing wholesale sharing agreement, incentivizes efficient operations indirectly by using parameters that are not necessarily in the utility's direct control, the GPIF directly focuses on encouraging improvement in areas of thermal efficiency (heat rate) and unit availability that are directly within the control of the utility. The Commission itself alluded to this fact in approving the GPIF, as well as the potentially straight-forward nature of the mechanism:

> The purpose of the Generating Performance Incentive Factor (GPIF) is to encourage utilities to improve the productivity of their base load generating units. Two factors over which a utility maintains some degree of control and which affect system generating mix, and hence total system fuel expense, are unit availability and thermal efficiency (heat rate). These two factors also lend themselves to analytical scrutiny since they are readily determined historically from actual plant records and are also independent variables in the production costing simulations of generating system operation used to project system fuel requirements and expense. For these reasons, unit equivalent availability and average heat rate were selected as appropriate performance indicators for use in the GPIF.[39]

The GPIF also benefits from the incentivizing statistics that directly benefit ratepayers. For example, a unit's heat rate represents the amount of energy that must be consumed per unit of electrical production. A lower heat rate thus indicates a unit that produces more power with every unit of fuel input. This improved thermal efficiency directly reduces fuel input costs, thereby lowering costs passed on to ratepayers through utility fuel clauses. Likewise, increasing a unit's EAF increases the ability of the unit to engage in economic sales that offset operating costs passed onto ratepayers.

---

[39] In re: Investigation of Fuel Cost Recovery Clause Application to Investor-owned Electric Utilities, Order No. 9558, issued September 19, 1980, in Docket No. 800400-CI, p 3.

Table 2 presents historic rewards and penalties assessed under the GPIF for the years 2012 through 2016. As can be clearly seen by this table, while the GPIF is effective in theory, elements of the mechanism are clearly not working as intended. For each investor-owned utility, the mechanism has on average produced greater rewards than penalties over the past five years. For one utility, FPL, the mechanism has produced incentives in each of the past five years. Furthermore, FPL has seen rewards under the GPIF that dwarf the incentives received by the other investor-owned utilities, even after accounting for differences in the customer bases of each utility.

	----- GPIF Rewards (Penalties) ----- ---------- ($ millions) ----------			
Year	Florida Power and Light	Gulf Power	Duke Energy Florida	Tampa Electric Company
2012	$ 7.70	$ 1.04	$ 1.50	$ (0.54)
2013	$ 20.68	$ 1.66	$ 3.26	$ (1.18)
2014	$ 11.81	$ 2.52	$ 2.23	$ 1.69
2015	$ 23.30	$ 2.65	$ (8.61)	$ 1.26
2016	$ 31.66	$ (0.05)	$ 2.26	$ 0.97
	$ 95.16	$ 7.83	$ 0.63	$ 2.20

Table 2: Historic GPIF Rewards and Penalties (2012-2016)

This disparity in performance may be due to the allowance for 'adjustments' to actual performance within the GPIF. For example, consider FPL's performance at two of its nuclear units, St. Lucie Unit No. 1 ("St. Lucie 1") and Turkey Point Unit No. 3 ("Turkey Point 3"), during 2012. The Commission approved a target EAF at St. Lucie 1 of 68.7 percent and Turkey Point 3 of 49.9 percent for 2012.[40] As part of these target EAFs, FPL had assumed planned outages of 2,184 hours at St Lucie 1 and 3,840 hours at Turkey Point 3. Instead, the planned outage hours at St. Lucie 1 totaled 3,432.5 hours and at Turkey Point 3 totaled 5,553.7 hours.[41] These additional

[40] In re: Fuel and Purchased Power Cost Recovery Clause and Generation Performance Incentive Factor, Order No. PSC-11-0579-FOF-EI, issued December 16, 2011, in Docket No. 110001-EI, p.21.

[41] In re: Fuel and Purchased Power Cost Recovery Clause and Generation Performance Incentive Factor, Pre-filed Direct Testimony of J. Carine Bullock, Docket No. 130001-EI, Exhibit JCB-1, p.6, filed May 13, 2013.

planned outage hours revised the actual EAF of 58.8 percent at St. Lucie 1 to an adjusted EAF of 72.5 percent. Likewise, an actual EAF at Turkey Point 3 of 35.9 percent was revised upward to 55.0 percent. Without these adjustments, FPL would have received a penalty for these two units' availability not meeting the targets FPL had calculated and the Commission approved. Instead, these units' availability after adjustments warranted the maximum reward.[42]

Consider additionally that the two Florida nuclear units, Turkey Point and St. Lucie, have also consistently operated at capacity factors below the national average. In 2012, the national average capacity factor for nuclear facilities was 80.95 percent, while FPL operated Turkey Point and St. Lucie at capacity factors of 49.38 and 54.07 percent, respectively. This lower capacity factor in 2012 could be explained by the refueling operations discussed previously. However, in 2013, the capacity factors for the two units were 65.49 and 82.55 percent, respectively. For the same year, the national average was 85.71 percent. Likewise, in 2014, the two units operated at capacity factors of 84.02 and 83.60 percent, respectively, while the national average was 87.07 percent. Finally, in 2015, the most recent year complete data is available, the two units operated at capacity factors of 90.97 and 79.67 percent, respectively, while the national average for nuclear plant operations was 87.68 percent. This means that, in the four years of data (2012-2015), only Turkey Point for one year (2015) operated at a utilization rate that met the national average for nuclear plant operations.[43]

There are other positive ways in which the GPIF can be improved. Specifically, the GPIF allows adjustments to be made to both EAF and unit average heat rate for such items as "an identifiable and justifiable change in the scope of a planned outage affecting total outage time,"

[42] In re: Fuel and Purchased Power Cost Recovery Clause and Generation Performance Incentive Factor, Pre-filed Direct Testimony of J. Carine Bullock, Docket No. 130001-EI, Exhibit JCB-1, p.5, filed May 13, 2013.
[43] Form EIA-860 and Form EIA-923, Department of Energy, Energy Information Administration.

and as "necessary to reflect changes in the economic dispatch of units during the period due to conditions not anticipated in advance." Both of these adjustments, as an example, provide utilities a free pass from poor operating conditions, assuming the utility was mindful enough not to recognize the deteriorating condition.

Indeed, the potential inconsistencies in the GPIF were referenced in the incentive mechanism workshop. Representatives from FPL noted that informal calculations it had performed found little correlation between GPIF incentives and the incentives the company received through its Asset Optimization Mechanism. This directly contradicts Staff's assumption that GPIF penalties will be offset by gains on off-system sales (included as part of its strawman asset management plan), thereby undermining the GPIF's effectiveness. However, of greater concern are the potential causes of this lack of correlation. It is very possible that the application of allowed adjustments within the GPIF allows utilities to receive incentives for poor generator efficiencies through the GPIF while additionally receiving incentives through the utility's asset optimization mechanism.

Furthermore, the GPIF measures performance against Commission designated targets. These targets are set in advance by the Commission; however, the targets are estimated against the utilities' own historical operations, and not a measure of the operations of like-situated facilities operating elsewhere in Florida or the U.S. This feature causes a situation where the GPIF does not measure the operational performance of a utility against best-practices established in the industry, but merely against prior performance to ensure limited performance degradation. Indeed, this could arguably discourage a utility to seek out best practice improvements as it may make the ability to obtain future GPIF incentives difficult.

OPC believes that the Commission could improve the GPIF by comparing its jurisdictional utilities' performances on unit availability and heat rate to like-situated facilities elsewhere in Florida and across the country. This data is readily available through the utilities' filings with the Federal Energy Regulatory Commission and Energy Information Administration. This improvement would encourage the Florida utilities to seek out industry best practices. Utilities which exceed their peers' performance would receive a reward; whereas, utilities which fall short would be imposed a penalty.

In summary, OPC agrees that the GPIF can be improved, particularly as it relates to its transparency and benchmarking provisions; however, it is not clear that the mechanism is fundamentally flawed. Contrary to the strawman's suggestions, the GPIF uniquely focuses on performance factors within a utility's control, and incentivizes utilities to operate their facilities at a level of performance that maximizes ratepayer benefits. Nevertheless, it should be noted that the GPIF is a mechanism first penned by the Commission in 1980, some 37 years ago, and may need to be updated. The mechanism is set up in a manner that is confusing and contains "adjustment" factors that can be potentially exploited by utilities to ensure they receive maximum incentive adjustments under the mechanism. Furthermore, the mechanism incorrectly evaluates utility performance based on historic performance, rather than a metric based on peer-operations or some other standard of best practices.

V. Conclusion

OPC appreciates the opportunity to provide the preceding comments to the Commission and its Staff regarding the strawman suggestions. OPC believes the suggested changes are premature and misguided. Staff appears to have put much thought into developing the strawman for purposes of stimulating a dialogue on the characteristics and objectives an optimal incentive regime will contain and will achieve. However, the strawman does not effectively consider exactly what ways the Commission's existing policies are deficient. The strawman assumes, as a given and without convincing evidence, that the Commission's existing policies are catastrophically flawed and in need of major reforms.

OPC does not agree with this premise. The majority of the Commission's incentive mechanisms, with the exception of FPL's Asset Optimization Mechanism, have operated for decades without significant controversy. Before agreeing to the radical changes that are embodied in the strawman suggestions, the Commission should require an evidentiary record be developed to first support the position that the Commission's current incentive mechanisms are deficient or not working as intended.

In the alternative, OPC recommends the Commission retain its existing wholesale sales incentive mechanism without modifications, allowing the Asset Optimization Mechanism in place for FPL to lapse at the end of the term of the existing settlement agreement. OPC additionally recommends the Commission improve the operations of the GPIF by removing the existing allowance for adjustments of historic operation metrics under the GPIF rules. Furthermore, the Commission should examine the potential to change the manner in which the Commission determines individual generator operation performance targets under the GPIF to incorporate a process that places generator performance against that of like-situated facilities elsewhere in Florida and across the country.