BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of incentive Mechanisms for the Electric Investor-Owned Utilities	DOCKET NO.: 20250032- EI FILED: April 10, 2026

POST-FEBRUARY 5, 2026 WORKSHOP COMMENTS OF THE CITIZENS OF THE STATE OF FLORIDA

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A. Introduction.

The Office of Public Counsel ("OPC") appreciates the Staff taking the important step to initiate this process to review, reform or re-think the Asset Optimization Mechanisms ("AOM")in place for Florida Power & Light ("FPL"), Duke Energy Florida ("DEF") and Tampa Electric Company("TEC"). The office sees the process as a significant opportunity to take a fresh look, take evidence and thoughtfully deliberate and issue an order or rule that is based on evidence about what incentives and what mechanisms are fair to customers.

At the outset, the OPC wishes to note is that we are not unalterably opposed to the existence of an incentive mechanism. We recognize that there may be circumstances were an incentive is in the best interests of the customers and is fair to both customers and shareholders. To this end the Public Counsel welcomes the start of a process that takes an objective, evidence and policy-based approach to establishing uniform and competitively-neutral mechanisms that optimize the recognition of the value of assets and products for the benefit of customers. If there are genuine "stretch" opportunities for the shareholder representatives to work harder to provide benefits or increase value for customers then perhaps the opportunity for sharing should be established or even increased.

Having said this, the OPC is concerned about steps the Commission has taken or proposes to take that have the effect of layering costs onto an already high electric bill.[1] Incentives that are not truly incentives only add gravy to an already oppressive

[1] A contemporaneous example is the Commission's proposal to effectively repeal of Commission Rule 25-14.004, F.A.C., the Parent Debt Adjustment, through a notice issued April 8, 2026. The repeal, styled as an amendment, would effectively gut an adjustment to lower revenue requirements that has saved customers hundreds of millions of dollars in the nearly half-century that it has been in place. The inexplicably aggressive efforts to repeal the rule would unfortunately complement the efforts to continue an assault on affordability that has seen record high ROEs in Florida compared to other states. Unnecessary incentives for actions that will occur anyway should not be added to the stockholder enrichment pile.

level of Commission-awarded profit (Return on Equity or ROE). Recent media reports are that Florida Power & Light customers currently pay the highest percentage (over 27%) in the nation of their base rates as profit to shareholders.[2] The customers do not see this nation-leading phenomenon as a good thing or badge of honor; quite the opposite, in fact.

As affordability of customer bills becomes a greater concern among an increasing percentage of the utility customers, along with the other elements of cost of living, the OPC urges the Commission to embrace opportunities like this process to hold the line on questionable incentives and to look for opportunities to impose belt-tightening on regulated utilities whose customers have no choice but to cut back on essentials. In rate cases, Florida utilities are rewarded with stockholder protections like pass-through clause revenue, cost of living adjustments, inflation adjustments, and incentive compensation, to name a few, while customers foot the bill and are increasingly being crushed under the weight of those costs – with no corresponding relief. The OPC heartily endorses and supports the remarks of Florida Rising. Especially relevant to this matter is the analysis that Florida Rising has performed to put the increase in IOU bills and profit recovery in stark dollar terms as a companion to the media reporting and research by the Energy and Policy Institute.[3]

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[2]Paying for Their Profits: How Ratepayers Foot the Bill for Soaring Utility Profits, Daniel Tait, Shelby Green and Sue Sturgis, Energy & Policy Institute, March 12, 2026. https://energyandpolicy.org/utility-profit-report/#h-section-3-methodology. The report is attached as Appendix A and has a calculator that allows long suffering customers to run the profits analysis for their utility. The profit percentage that is noted, only relates to the dollars that go to the shareholders. OPC expert Dan Lawton testified in the recent FPL rate case that 49.59% of every dollar customers pay to FPL goes to pay for the shareholder profit ***and*** the stockholders' income taxes on that profit. See Document No. 04337-2025 filed in Docket No. 20250011-EI at pp. 11-12.

[3] *Id.*

The OPC's comments are principally composed of these introductory remarks, a historical background of the evolution of the original, pre-2012 AOM programs (including the orders that are the foundation of the process that has led to the current checkerboard AOM regime), and an affidavit by OPC expert Richard Polich. (See Exhibits 1 and 2 for his Affidavit and *curriculum vitae*.)

The analysis in this affidavit provides a surrogate for analyzing the basis for whether the Commission should allow (and, if so, how) the different types of products included in the Florida generating electric IOUs' AOMs.[4] Mr. Polich challenges some of the conventional assumptions underlying the incentives related to the wholesale power transactions and opines that the agency should temporarily freeze any modification of the existing AOM's pending implementation of a uniform regime by generic order or preferably rule. Mr. Polich recommends that the agency also seriously consider adopting the concept of joint economic dispatch approach used in many states, in lieu of the current potentially misguided and largely evidence-free incentive approach.

B. Background.

In its 1984 Stockholder Sharing Order (Commission Order No. 12923)[5] the Commission implemented the initial version of asset sharing in the form of allowing shareholders to retain as much as 20% of the gains on wholesale (economy) power sales. The Commission defined these transactions this way:

> Economy energy transactions represent the sale of energy between electric companies. Gains are realized by the selling company as a

[4] See page 8 of the January 26, 2026 Notice of Staff Workshop in Docket No. 20250032-EI, containing a comparative listing of the various asset optimization opportunities by generation electric IOU.

[5] Issued January 24, 1984, Docket No. 830001-EU, In re: Fuel Adjustment Recovery Clauses of electric utilities - treatment of gain on economy sales. Attached in Appendix B.

result of the split-the-savings methodology used to calculate the selling price of economy energy. [6]

For the next 16 years this process became of fixture of the fuel docket where the accounting for these sales had been moved from base rates by that order. Although called an "incentive" in the historical description of the mechanism that evolved in the 1983 hearing process, it is clear that the inception was more one of regulatory accounting fairness and not intended or designed to give an incentive for the shareholders to work harder. On this point, the 1984 Stockholder Sharing Order recounts the difficulty of accurately projecting the economy sales profits in determining revenue requirements in the base rate cases where these transactions were initially recognized. As the following passage indicates, there was a concern about the incentive of utilities to under forecast profits in a way that created shareholder windfalls if economy sales exceeded forecast "due to uncertainty associated with fuel prices, weather, and forced outages of generating units and transmission lines." These factors were largely outside of the control of the utility. The 1984 Stockholder Sharing Order stated:

> At hearing, on December 15, 1983, Staff witness, C. K. Hvostik, proposed that the treatment of a gain on economy energy sales be transferred from general rate proceedings to the fuel adjustment docket and be transferred from the base rates to the fuel and purchased power cost recovery clause. ***The chief reason for this proposed treatment was to eliminate the potential for over or under recovery of revenues associated with economy energy sales.*** In addition, the Staff witness proposed that the selling utilities be allowed to retain 20% of the economy sales profit for their shareholders and that the remaining 80% be credited to ratepayers through the fuel and purchased power cost recovery clause. The proposed treatment would also remove from rate cases the difficult issue of what level of economy sales profits to include in base rate. Under current rate case treatment a utility is rewarded if actual economy sales profits exceed the projected amount

[6] 1984 Stockholder Sharing Order, at 2.

> included in the test year and penalized if the actual economy sales are less than projected. Problems with the current treatment stem from the difficulty in projecting economy sales and the potential bias of a utility to under project their economy sales profits. The difficulty in projecting economy sales profits is due to uncertainty associated with fuel prices, weather, and forced outages of generating units and transmission lines. These variables affect not only how much a utility can sell and at what price, but also how much other utilities will buy at different prices.[7]

(Emphasis added.)

Accordingly, the Commission moved the accounting for these gains related to these economy energy transactions to the fuel clause. The establishment of the 80/20 sharing appears to be a recognition of the history of some profit sharing under the base rates recognition methodology. To call this an incentive seems to be a misnomer. If anything, the original "incentive" mechanism merely removes the disincentive or, as the Commission noted, "potential bias of a utility to under project their economy sales profits."

In its 2000 Stockholder Sharing Order[8], the Commission revisited the issue of the need to by stating this:

> At page 2 of Order No. 12923, we stated that "[t]he chief reason for this proposed treatment was to eliminate the potential f o r over-or under-recovery of revenues" associated with economy energy sales." Further, we authorized the IOUs to keep 20 percent of the gains on these sales as an incentive to "maximize the amount of economy sales and provide a net benefit to the ratepayer." In other words, the incentive was created, in part, to encourage the IOUs to use their *excess* capacity to make economy sales, with 80 percent of the revenue from those sales being credited to the ratepayers.[9]

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[7] 1984 Stockholder Sharing Order at 3-4.
[8] Order No. PSC-2000-1744-PAA-EI, issued September 26, 2000, in Docket No. 19991779-EI, at 2. Attached as Appendix C.
[9] *Id.,* at 2.

This introduction was part of what fueled the mythology that the incentive was about providing incentives that benefit customers. Apparently this notion was carried forward unquestioned into the current expansive era of incentive mechanisms.

In that 1999-2000 re-visitation of the mechanism, the Commission framed the proceeding that led to the order by stating:

> At our November 22-23, 1999, hearing in Docket No. 99000-EI, the panel heard arguments about whether this incentive mechanism is still necessary or appropriate. By Order No. PSC-99-2512-FOF-E, issued December 22, 1999, a proceeding was instituted so that the full Commission could hear this matter. Accordingly, an evidentiary hearing was held on May 10, 2000, and post-hearing briefs were filed by the parties.

As a preliminary observation, this determination about whether an incentive was necessary or even a good idea and, if so, what sharing threshold should be implemented, was based on an evidentiary record, a hearing, and briefing. This is a significant fact. Another significant element of the 2000 Stockholder Sharing Order is that the Commission recognized that there is "no way to precisely measure the effect of a shareholder incentive." This statement was made against the backdrop of another acknowledgement by the Commission – that there were other factors beyond the existence of the 20% shareholder incentive that affect the IOUs' participation in the wholesale market.[10] Throughout the 2000 Stockholder Sharing Order the Commission made note of certain guiding principles including stating that the shareholder incentive should be "properly structured."[11]

The Commission acknowledged that there was no "magic number" for an appropriate incentive level and cautioned that any incentive "should not be designed

[10] 2000 Stockholder Sharing Order at 6.
[11] *Id*., at 6, 8, 9.

to encourage behavior that is already occurring" and "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."[12]

The Commission cited OPC witness David Dismukes admonition to avoid setting the threshold too low as it "will create the potential for a free rider effect, rewarding utilities for behavior which is taking place for reasons other than the incentive." [13] Notably, when rejecting Mr. Dismukes recommended five-year moving average period in favor of the three-year period ultimately adopted, the Commission effectively set an important standard for future consideration of establishing any incentive threshold. Of the OPC's (and, by extension, customers') proposed five-year moving average, the agency said, "we believe this approach[14] would reward the IOUs for *normal effort*, rather than *the superior effort that should be required* to receive an incentive." The Commission also stated that the 80/20 split of gains above the sharing threshold "minimizes the possibility that the IOUs could be rewarded for behavior that is already occurring."[15]

One of the somewhat concerning elements of the 2000 Stockholder Sharing Order is evidence of some of the circular logic that threatens the current process. As discussed above the Commission admitted that no "magic number" exists for the sharing percentage. In that context the Commission stated the following:

> As witness Wieland conceded, the 20 percent figure is subjective in that there is no scientific basis used in selecting that percentage. However, we find that a 20 percent incentive is consistent with Order No. 12923, is reasonable, and should provide utilities with an adequate incentive.[16]

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[12] *Id*., at 9.
[13] *Id*., at 10. (Emphasis added.)
[14] The Commission believed that the five year period would, at that time apparently, capture years before the market stimulating FERC Orders 888 and 889 were issued and thus effectively result in setting the incentive threshold too low. 2000 Stockholder Sharing Order at 10.
[15] 2000 Stockholder Sharing Order at 11. (Emphasis added.)
[16] *Id.*

The 2000 Stockholder Sharing Order tacitly acknowledges that the 20% is just continued because it is the same value approved in 1984. Despite the "magical" nature of the number that was essentially plucked from the air 16 years earlier, the shareholders' 20% retention was approved for the expansion of the incentive-eligible transaction gains apparently because it was already in place. As discussed below, this "bootstrapping" is a threat to the underpinnings of a possible standardization approach to incentives in 2026.

Also notable is that the 2000 Commission rejected, after taking evidence and receiving briefing, that the sliding scale proposed by FPL was "subjective and not based on evidence."[17] This pronouncement is significant in the current incentive evaluation process.

For the past 25 years this 2000 Stockholder Sharing Order remains the only final[18] order establishing incentive sharing for all IOUs. It is also the only such incentive mechanism establishment order that is based on an evidentiary record, with full discovery, sworn testimony and briefing. For a 12 year period this paradigm was the only one that covered incentives industrywide.

[17] *Id.*

[18] Commission Order Nos. PSC-2025-0038-FOF-EI (TEC) and PSC-2026-0022-S-EI are currently on appeal to the Florida Supreme Court. Briefing has either yet to begin (FPL) or has not been completed (TEC) and experience would suggest that an opinion would be unlikely before late 2027. The 2024 DEF Settlement Agreement approved in Order No. PSC-2024-0472-AS-EI will expire on December 31, 2027.

C. Current Era of Rapid Expansion of AOM.

Beginning in 2012 the incentive mechanism began evolving into a rather circular negotiated hodgepodge[19] of sharing/optimization of assets and values-related sharing points. The inception point for this expansive era of increases shareholder extractions from the gains from normal operations of the utilities was in the 2012 FPL rate case settlement (to which the OPC was not a signatory).[20] There FPL AOM suddenly appeared as an item negotiated among a very select group of self-interested parties and excluded the OPC and representatives of small businesses. The disputed agreement was filed on the eve of hearing, less than six months into a rate case docket. The AOM was not part of the original filing. FPL AOM and the Florida Supreme Court also rejected the OPC contention that the provision was not based on competent substantial evidence by saying:

> As demonstrated below, competent, substantial evidence demonstrates that this provision is part of a reasonable resolution *of all the issues*, is in the public interest, and does not result in unfair rates.

The Court further stated that:

> Accordingly, the commission's conclusion that the asset optimization incentive program is in the public interest and part of a reasonable resolution of disputed issues is supported by competent, substantial evidence.

What the 2014 Court may have gotten a little bit sideways on here is that the AOM and the fuel clause were not part of the "issues" raised in the conventional case that was originally filed. The only issues that were "disputed" were raised by virtue of the AOM being inserted into a disputed agreement and then challenged by

[19] See page 9 of the January 26, 2026 Notice of Staff Workshop in Docket No. 20250032-EI, containing the various sharing points and sharing percentages among the generation electric IOU AOM programs.
[20] Docket No. 20120015-EI.

the OPC. In the end the Commission's approval of the initial AOM was based on the fact that it was part of a comprehensive settlement.

It is important to note that the Commission did not suggest that FPL's AOM was approved on a stand-alone basis and on its own merits. The Court's approval was based on the more generic public interest standard. [21] At no time has the Commission taken comprehensive evidence to determine if the mechanism and its components are necessary and working as intended or in accordance with the principles set out in the 1984 and 2000 Stockholder Sharing Orders. There was no evidence taken as to whether the AOM could be subject to manipulation or at least unintended consequences or whether an AOM is even prudent on a stand-alone basis or should be made permanent. If the 2012 minority settlement agreement had instead included "and a rabbit," this would account for the unprecedented surge in the numbers of rabbits in subsequent Commission rate cases without ever examining the need, purpose, or support for said rabbits. Indeed, customers would prefer that rabbits had been the unique, unsupported, unpled, and unwarranted mechanism to transfer unwarranted profits awarded in 2012 as it would distinguish it from the plethora of other emerging and equally unwarranted profit-boosting commission-approved mechanisms that contribute to increases to customer bills. Although the AOM burdens upon customers appear to multiply like rabbits, they are nearly impossible to distinguish from the rapidly emerging group of commission-crafted/non-statutory profit boosting mechanisms.

Throughout the following timeline the other two utilities – DEF and TEC joined the incentive club.

[21] The OPC is not taking issue with the Court's decision in 2014. Rather the intent is to stress that regardless of the merits of the appellate review process, there was no evidentiary hearing about the elements of the AOM, the sharing points, validity of incentives or the products or revenue streams that were included.

The AOM/incentive expansion timeline is:

1. FPL 2012 - AOM pilot program initiated in a non-unanimous, contested special interest agreement. Ostensibly terminable after 2 years.
2. TEC 2013 - filed petition for am AOM program based on FPL'S AOM; withdrawn.
3. TEC 2016 - Filed a petition for AOM program based on FPL's AOM pending when resolved in TEC 2017 settlement.
4. FPL 2016 - negotiated agreement with – OPC (and others) AOM renewed and included in 4 to 5-year term.
5. TEC 2017 - negotiated with OPC (and others) AOM included (based on 2016 petition for a pilot, which was based on FPL) and authorized for a 4-year term.
6. FPL 2021 - AOM negotiated and made evergreen.
7. DEF 2024 - Negotiated AOM for first time by inclusion in a settlement agreement with OPC and others authorized for a 3-year term.
8. TEC 2024 rate case - adopted by rate case order from 2017 agreement. "Cherry picking" aspect on appeal.
9. FPL 2025 - In an unlawful settlement FPL's 2021 AOM revised by a non-final order though a process similar to 2012 non-unanimous, contested special interest deal. Minority signatories awarded FPL the first $150 million of all gains to FPL stockholders in order to contribute to helping them earn an extra $500 million in annual profits. Entire special interest agreement is now on appeal.

The take away of this timeline is that the level of stockholder extractions through the blossoming AOM mechanism has steadily increased – explosively so in the case of FPL. This has occurred as the product of multiple layers of evidence-free bootstrapping and circularity that originated exclusively in 2012 from secret negotiations from which most customers were excluded, thereby bypassing the taking of evidence on the fundamental elements of the original FPL AOM.

The OPC acknowledges that it has been a party to the establishment of the AOM programs at TEC and DEF. Fairness to other utilities (including parity with what FPL had gained in its lopsided 2012 special interests agreement), ***plus*** the opportunity for customers to gain real trade off or *quid pro quo* value in the settlements, allowed for the implementation of time delimited programs for DEF and TEC. In 2021, with what must be assumed to have been the knowing agreement of the OPC, language was inserted into the FPL AOM provision that made the program evergreen (i.e., not a pilot or expiring).[22] That leap was further superseded in 2025 in another special interest deal that converted the AOM to delivering the first $150 million of gains entirely to the stockholders.

From the OPC standpoint the relatively modest incentive that was actually not truly an incentive, as demonstrated in the 1984 and 2000 orders, at the embarkment point of that journey has turned into a veritable runaway train with the 2025 FPL special interest deal as evidence of this. The $150 million grab in the 2025 version is where the incentive train jumped the tracks.

[22] There is no mention of the conversion of the AOM to evergreen status in the initial Commission order approving the 2021 FPL Stipulation and Settlement Agreement. See, Order No. PSC-2021-0446-S-EI at 8-10, 18.

D. OPC Proposal.

For these reasons, the OPC presents the affidavit of Mr. Polich as an approach to level-set and take a fresh look at this so-called incentive process. Mr. Polich challenges the assumptions underlying the 1984 and 2000 foundational orders. In his challenge he posits risks that customers face, lays out a set of principles that should apply to incentives if they are to be fair to all. He also proposes that the Commission take a fresh look at whether joint economic dispatch would be viable in Florida as a way to remove the possibility of unnecessary wealth transfers among customer groups and from customers to stockholders.

To facilitate this fresh look the OPC also requests that the Commission enter an order that would effectively freeze the existing AOMs through at least December 31, 2027 and the end of any of the two pending appeals (TEC and FPL), whichever is later. Any continuation of incentives thereafter should be based on evidence and meaningful and fair principles, adopted after a full evidentiary hearing. The OPC concurs with Florida Rising that the ultimate governing document should be a rule. The Commission should also consider adjustments to the ROE that recognizes the lessening of risk that could occur from incentives that are not soundly based. Ideally a full resolution of the case would result in an evidence based order whether generic to all IOU electric companies or a rule that was subject to a "draw out" under section 120.54(3)(c)2, Florida Statutes.

On a special note, in the 2012 FPL rate case, settlement portion, the OPC filed the testimony of an expert, James W. Daniel, to specifically address the never before seen AOM. It is instructive to review the prophetic words contained in that testimony at page 5:

> Based on my review of the August 15 document and testimony of FPL witness Sam A. Forrest filed on October 12, 2012 in support of it, I recommend that the Commission not approve paragraph 12 of the

> August 15 document, which would provide FPL with significant additional margin sharing opportunities. These proposed new margin sharing provisions were not included as part of FPL's original rate application and ***have been sprung on the parties***, the Commission, and other utilities and potentially affected entities who are not parties to this case, through the August 15 document. The procedural schedule does not provide the parties, or other affected entities, the opportunity to conduct adequate discovery on the significant proposed changes to the incentive rate mechanism and ***does not provide them sufficient time to analyze fully the implications*** of these proposed changes. In addition, if the August 15 document is approved, the types of rate incentive mechanism changes proposed ***are likely to be sought by other utilities***. Therefore, these proposed modifications ***are better considered in a generic rulemaking*** proceeding rather than in an expedited proceeding to consider a company-specific rate case stipulation. Perhaps more significantly, in my opinion the expanded incentive mechanism proposed by the signatories ***is unacceptably vague and open-ended; encompasses areas that prudent management should pursue without the necessity of incentives***; and could result in unintended consequences, including a ***potential deterioration of reliable retail service and higher costs to ratepayers***.

These words have largely proven true, even though they were cast aside in the rush to approve the very first special interest deal. The OPC commends them to the Commission's consideration and have included the entire testimony for reference as Appendix D.

With respect to the Staff proposal presented on February 5, 2026, the OPC agrees with and adopts the comments of Florida Rising regarding the Staff proposals. Additionally, the Staff should consider not supporting a tiered or "sliding scale" incentive approach. The 2000 Stockholder Sharing Order rejected this approach as noted above because it was subjective and not based on evidence. The same defect persists today we are still waiting, a quarter of a century later, for that the evidentiary

hearing.[23] Similarly, the Commission should not assume that because the OPC might have been a party to a settlement agreement and have agreed to implementation of an AOM program, the types of assets and gains, the sharing thresholds and values have not been endorsed or supported in any way by the OPC. The agreements each contain specific non-attribution clauses that note that all terms of each agreement were the product of compromise.[24]

Conclusion

Given the history of the AOM/incentive process, the excessive level of utility profits and customers rates and bills, and the lack of evidentiary support along with the concerns raised in the attached Affidavit of OPC expert Richard Polich, the Commission should step back and take a fresh look at the entire incentive and asset optimization process. This step back and fresh look should be accompanied by an in-depth, evidenced based study and hearing process that determines if incentives are needed and, if so, to what degree and with what optimal design. The OPC suggests that the Commission also consider other options that would be more

[23] Apparently in 2016 there was mention of holding such a hearing or at least providing the opportunity for one, but it never happened. See Document No. 09540-2016 in Docket No. 20160160-EI, date December 20, 2016.

[24] See, for example, Order No. PSC-2021-0423-S-EI, issued November 10, 2021, at 50 (paragraph 16(b)):

> No Party will assert in any proceeding before the Commission or any court that this 2021 Agreement or any of the terms in the 2021 Agreement shall have any precedential value. The Parties' agreement to the terms in the 2021 Agreement shall be without prejudice to any Party's ability to advocate a different position in future proceedings not involving this 2021 Agreement. The Parties further expressly agree that no individual provision, by itself, necessarily represents a position of any Party in any future proceeding, and the Parties further agree that no Party shall assert or represent in any future proceeding in any forum that another Party endorses any specific provision of this 2021 Agreement by virtue of that Party's signature on, or participation in, this 2021 Agreement.

beneficial to customers without also increasing or providing the incentive to increase rate base.

Respectfully submitted,

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CERTIFICATE OF SERVICE
DOCKET NO. 20250032-EI

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Exhibit 1

Affidavit of

Richard A. Polich

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of Review of Incentive Mechanisms for the Electric Investor-Owned Utilities	Docket No. 20250032-EI Date: April 10, 2026

AFFIDAVIT OF RICHARD A. POLICH

I, RICHARD A. POLICH, being first duly sworn, depose and say:

1. My name is Richard A. Polich. My business address is 1850 Parkway Place, Marietta, GA 30067. I am a Senior Director at GDS Associates, Inc. ("GDS"), a multidisciplinary engineering and consulting firm offering expertise in regulatory ratemaking, accounting, economics, finance, and engineering for matters associated with electric, gas, and water utilities. I make this affidavit based on my personal knowledge and professional experience, and I submit it in support of the Florida Office of Public Counsel comments regarding incentive mechanisms (also known as Asset Optimization Mechanisms ("AOM")) for the investor-owned electric utilities.

2. The purpose of this affidavit is to provide additional context on certain matters related to the philosophical underpinnings of the AOM application and recommendations on future approach(s) to the AOM. Specifically, I offer research on AOM programs in other jurisdictions, pros and cons of maintaining an AOM, and the AOMs' fairness to customers. This Affidavit also includes recommendations on future AOM course of action. I am focusing these affidavit comments on the specific component of all the current generating investor owned utilities' ("IOU") AOM programs – Florida Power & Light ("FPL"), Duke Energy Florida ("DEF"), and Tampa

Electric Company ("TEC"). This focus assumes that similar concepts discussed below apply to the various other components contained in the three IOUs' varying AOM programs. I recommend that there be a freeze on any modifications to current programs, pending establishment of uniform criteria after evidentiary hearing.

I. Florida Electric AOM Programs Overview

3. State and federal regulatory authorities have long employed utility incentive mechanisms to align utility behavior with public policy objectives that may not be fully achieved under traditional cost-of-service regulation. These incentive mechanisms are designed and intended to encourage utilities to pursue outcomes that promote efficiency, reliability, customer value, and long-term system optimization, while preserving appropriate regulatory oversight. Historically, incentive programs have been most commonly applied in areas such as energy efficiency, demand-side management, and renewable resource development, where utilities may otherwise face financial disincentives to reduce sales or defer capital investment.[1,2,3] Performance-based incentives in these areas are intended to motivate utilities to design,

[1] Minnesota – Energy Conservation and Optimization (ECO) Performance Incentive
The Minnesota Public Utilities Commission authorizes electric and gas utilities to earn a financial incentive for meeting or exceeding statutory energy efficiency savings goals under the Energy Conservation and Optimization Act. The incentive is calculated based on verified net benefits of efficiency programs and is payable only upon demonstrated performance beyond minimum requirements.

[2] Michigan – Energy Waste Reduction (EWR) Shared-Savings Incentive
Under the Energy Waste Reduction Act, the Michigan Public Service Commission allows utilities to earn shareholder incentives of up to 25 percent of approved energy efficiency program expenditures when utilities exceed annual energy savings targets, subject to additional performance conditions and independent evaluation.

[3] Colorado – Multi-Metric Energy Efficiency Performance Incentives
The Colorado Public Utilities Commission authorizes performance-based shareholder incentives for electric and gas utilities tied not only to energy savings, but also to additional metrics such as demand reduction, low-income participation, and long-term system benefits, reflecting a multi-factor performance incentive mechanism.

implement, and administer programs that deliver measurable benefits to customers, including reduced energy consumption, lower system costs, and improved environmental outcomes. More recently, incentive mechanisms have been expanded to include utility operational and asset-related objectives, such as cost control, service quality, and, in limited circumstances, asset optimization.

4. When properly structured, such mechanisms can encourage prudent decision-making, innovation, and efficiency beyond what might be achieved under traditional regulatory frameworks alone. However, incentive programs also introduce additional complexity and risk. Poorly designed mechanisms may weaken cost discipline, transfer undue risk to customers, or reward outcomes that would have occurred absent the incentive. Thus, regulators who believe that incentives will be beneficial to customers, need to structure incentive programs with clear performance metrics, transparency, symmetry between rewards and penalties, and rigorous monitoring to ensure that incentive mechanisms provide net benefits to customers, while remaining aligned with the public interest.

5. Reliability and Service Quality Incentives is an example of utility incentive mechanism which is intended to encourage utilities to improve service reliability and quality. System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) are foundational metrics used in Performance-Based Regulation (PBR) to create Earnings Adjustment Mechanisms (EAMs), also known as Performance Incentive Mechanisms (PIMs). These mechanisms tie utility earnings directly to their reliability performance, rewarding companies for exceeding targets and penalizing them for underperformance. These programs use metrics, such as outage frequency and duration, customer complaint levels, or response times for

service restoration, to measure utility performance in the area of service reliability and quality.[4,5] These incentive programs also include opportunities for utilities to receive additional earnings for superior performance or incur financial penalties for failure to meet minimum performance requirements. The stated goal of these programs is to encourage utilities to maintain or improve service quality beyond minimum standards, while providing regulators and customers with transparent performance measures. There are other similar examples of utility incentive programs for cost control, operational efficiency, capital project execution, and performance-based regulation. The key to a successful utility incentive mechanism is its ability to monitor performance metrics, creating transparency, insuring symmetry between rewards and penalties, and containing a provision for rigorous monitoring of the utility performance.

6. Based on my review of the Florida electric AOM programs associated with profits from wholesale electric sales, it appears these programs lack clear performance metrics, transparency, symmetry between rewards and penalties, and do not provide for rigorous monitoring to ensure that incentive mechanisms provide net benefits to customers and remain aligned with the public interest.

II. Florida Electric AOM Programs Intended Benefits

7. The Florida electric AOM programs are intended to provide investor owned utilities an incentive to act in the ratepayer's best interest by increasing the utilization of existing generation

[4] Illinois – SAIDI and SAIFI Reliability Performance Incentives: The Illinois Commerce Commission has authorized financial incentives and penalties tied directly to utility performance on reliability indices such as SAIDI and SAIFI, creating symmetric accountability for outage frequency and duration relative to Commission-approved benchmarks.

[5] Hawaii – Reliability Performance Incentive Mechanisms under Performance-Based Regulation The Hawaii Public Utilities Commission implemented a Performance-Based Regulation framework that includes performance incentive mechanisms tied to reliability, outage management, and service quality outcomes, providing additional earnings opportunities contingent on measurable improvements beyond historical utility performance.

through wholesale economic sales. Based upon review of generation assets in the state, Florida lacks any form of true, inter-utility economic dispatch of Florida generation assets based upon lowest total variable costs. This AOM is a substitute for requiring utilities to economically dispatch all generation assets based upon true, total variable cost of generation. Because Florida utilities are not required to jointly economically dispatch all generation assets, and since any economic benefits from wholesale sales would only flow to ratepayers, investor owned utilities have no incentive to utilize existing generation assets for economic wholesale sales. Thus, the Florida PSC appears to have implemented electric AOM programs with the expressed intent change investor owned utility behavior, related to utilization of existing generation assets.

8. Even prior to the Federal Energy Regulatory Commission ("FERC") establishing Regional Transmission Organizations and Independent System Operators ("RTOs" and "ISOs") in Order No. 2000 (dated December 1999), various U.S. jurisdictions had already discovered the ratepayer benefits of joint economic dispatch of generation assets. Michigan implemented joint economic dispatch of its two investor owned utilities, Consumers Power Company and Detroit Edison Company, in the early 1970s. The Michigan ratepayer savings were estimated to be in the hundreds of millions annually, based upon evidence submitted in various rate cases.[6]

9. Assessment of whether or not the Florida electric AOM programs are accomplishing the goal of changing utility decision making to benefit ratepayers, requires a thorough review of all appropriate metrics and impact on overall utility rates throughout Florida. Analysis of the wholesale power sales component, for example, of the Florida electric AOM

[6] Michigan PSC rate cases and fuel-cost recovery proceedings involving Detroit Edison and Consumers Power in the late 1960s and early 1970s include evidence that coordinated, cost-based economic dispatch reduced fuel and production costs relative to independent utility operation, resulting in recurring, system-wide ratepayer savings and supporting Commission-directed joint dispatch requirements.

programs ratepayer benefits on a utility by utility basis, will fail to determine if the AOM program is resulting in overall lower utility costs. This is due to the way in which ratepayers are charged for any wholesale power (generation) costs utilities incur and how the AOM programs provide incentive to the investor owned utilities. The possibility that the electric AOM programs could be actually causing an increase in cost to ratepayers in Florida without providing true benefits cannot be ignored and should be addressed in any revisions to the mechanism, as will be demonstrated later in this Affidavit.

10. An option to the AOM programs is for the State of Florida to adopt a requirement for all Florida utilities to economically dispatch all generation assets, as is done throughout most of the rest of the United States. Joint economic dispatch of generation assets would eliminate the need to reward utilities for executing wholesale sales that benefit all Florida ratepayers, a practice that should be exercised on a normal basis and is considered to be good utility practice. I do not profess to know what steps – legal or otherwise – would be required. I do know that it has been implemented in many other states and on that basis alone, I believe that it should be considered. It goes without saying that any implementation of joint economic dispatch of generation assets should in no way be transformed into an opportunity to bulk up rate base in a cost inefficient way.

11. To adequately determine if the investor owned utility AOM programs are resulting in overall benefit to Florida ratepayers, I recommend that the Florida Public Service Commission Staff perform, at least for the wholesale power sales component of the AOM, a comprehensive analytical investigation of the combined impact of wholesale power costs, wholesale power revenues, cost of wholesale power production, and the cost impact of the AOM programs' incentives on ratepayer rates and bills. Similar steps should be considered for other elements/products of the AOM. Only in this manner can the true impact on ratepayers be

determined and the assessment of the value of the investor owned electric utility AOM programs be determined.

III. Florida Electric AOM Programs Potential Detrimental Impact

12. My review of the Florida electric AOM programs suggests that the programs lack the following fundamental parts of most utility incentive programs:

A. Lack of symmetry between risk and reward. Under the Florida AOM programs, utilities have zero risk and only the opportunity to receive a reward. Florida's AOM programs lack meaningful downside risk or penalties if utility actions increase costs, distort dispatch decisions, or fail to deliver net benefits to customers. This asymmetry weakens accountability and allows utilities to capture earnings benefits without them assuming corresponding financial risk.

B. Clear metrics do not appear to exist on which to measure if a Florida electric AOM program is causing investor-owned utilities to:

- Act in the ratepayer's best interest,
- Demonstrate whether the incentives have truly changed the utilities behavior, and
- Demonstrate whether the utilities are taking actions they would not have taken without incentives.

C. Lack of transparency and verifiability whether the Florida electric AOM programs are achieving the intended changes in utility behavior and benefiting Florida ratepayers as a whole.

D. The Florida electric AOM programs do not incorporate rigorous monitoring and tracking of the metrics to determine program success.

E. Current assessment of Florida electric AOM programs are on a utility by utility basis, which fails to assess overall Florida ratepayer impact, nor does it include the necessary metrics to determine if it is cost effective.

F. Florida's electric AOM programs have the potential to be abused by utilities executing wholesale power purchase transactions that are overpriced and not market-based given that not all stakeholders are involved in Florida regulatory proceedings. Florida utilities purchasing wholesale power, are almost assured of full wholesale power cost recovery from ratepayers through the annual fuel cost adjustment proceedings, because there are no metrics to measure the contract prices to market prices. To the extent that Florida utilities purchase wholesale power at costs above market their ratepayers would be charged higher rates and under the current Florida electric AOM programs, those utilities selling wholesale power above market prices would be rewarded. To the extent there would be gains on such sales, this would result in a simple transfer of wealth to the selling utility shareholders without justifiable cause. The underlying circumstances of such transactions cannot be tracked under current Florida electric AOM programs.

G. Utilities should not be allowed to earn incentives to perform actions that represent normal, and prudent best utility practices that are typical in the rest of the utility industry. Economic dispatch of generation resources based on least variable cost is widely accepted as standard utility practice. Florida's AOM programs substitute financial incentives for wholesale energy sales for what should be a mandatory operational requirement. A better approach would be serious consideration of addressing the underlying absence of joint, statewide economic dispatch.

13. When measured against standard regulatory principles for incentive design, Florida's electric AOM programs fail to include many of the foundational elements necessary to protect ratepayers and ensure effective outcomes. The lack of clear metrics, symmetry, transparency, and comprehensive cost evaluation significantly limits the Commission's ability to determine whether AOM incentives are producing real economic benefits or are instead increasing costs while transferring risk to customers.

IV. How Florida electric AOM Programs Could Cause Economic Harm to Ratepayers

13. Florida's electric AOM programs present similar structural vulnerabilities. The AOM rewards wholesale transaction profits without requiring demonstration that transactions reflect least-cost dispatch, produce net system-wide savings, or align with market-based pricing benchmarks. Unless current market based prices are included in the AOM programs' evaluation, system-wide cost metrics, symmetry between rewards and penalties, and comprehensive monitoring, the AOM creates a risk that utilities could engage in transactions that increase overall costs to ratepayers while employees managing the process may be earning incentive compensation, resulting in wealth transfers rather than genuine economic optimization.

14. The following is a simplified example that illustrates how Florida ratepayers could be harmed under Florida's electric AOM programs. Assume a Florida utility (called "ABC Electric") purchase 50,000 MWh of wholesale power from another Florida utility (called "XYZ Electric") at a cost of $65.00/ MWh over a specific period ("Sale Period"). XYZ Electric's total variable cost of producing the wholesale power is $55.00/MWh (Cost includes variable operating and maintenance costs, fuel costs and other variable costs). If generation in Florida were dispatched on an economic basis, then the ABC Electric would only have paid $55.00/MWH for the wholesale

power. ABC Electric has overpaid $500,000 for the wholesale power (50,000 MWh times ($65.00/MWh - $55.00/MWH)). ABC Electric recovers the $500,000 of excess wholesale power transaction costs from its ratepayers through the fuel cost adjustment proceeding because the lack of wholesale power market transparency prevents the introduction of evidence that the wholesale power costs presented by ABC Electric are above market prices. XYZ Electric records the wholesale power transaction under a Florida electric AOM program as a $500,000 profit, sharing 80% with its ratepayers ($400,000) and pocketing 20% ($100,000). ABC Electric does not incur any penalty for engaging in above market wholesale power purchase and XYZ Electric shareholders are rewarded with $100,000 in additional income. But Florida ratepayers on the whole are economically harmed because ABC Electric's ratepayers pay $500,000 more than they should, XYZ Electric's ratepayers are credited only $400,000 of the wholesale power sales profit, resulting in a net economic loss of $100,000 to Florida's ratepayers overall. This is a transfer of wealth from ABC Electric's ratepayers of $400,000 to DEF Electric's ratepayers and $100,000 to XYZ Electric's shareholders.

15. This scenario can occur because of the following characteristics of the wholesale power transaction component of the Florida electric AOM programs:

A. Florida wholesale power trading market and does not include dispatching all Florida generation based on lowest variable cost.

B. The Florida electric AOM programs' incentives are calculated on a utility by utility basis.

C. The metrics used to calculate Florida electric AOM programs' incentives are not transparent or rigorously evaluated.

V. Recommended Course of Action

16. Based on my review focusing on the wholesale power transaction component of the Florida electric AOM programs, I recommend that all AOM incentives be frozen pending the resolution of ongoing appeals in the 2024 Tampa Electric Company case, the FPL 2025 rate case and the expiration of the Duke Energy Florida 2024 settlement agreement on December 31, 2027. During this freeze period a fresh look at all incentive mechanisms, preferably by the Florida PSC Staff should be undertaken with a comprehensive evaluation to determine if the Florida AOM programs are truly resulting in net economic benefits to all Florida ratepayers. This will require evaluation of all the metrics associated with Florida wholesale power transactions, power generation costs, and ratepayer economic impacts. The report should also include an evaluation of the economic benefits to Florida ratepayers of economic generation dispatch. The freeze period should continue until at least January 1, 2028 and beyond if required until a uniform set of incentive mechanisms, if any, are established consistent with the principles outlined here, after an evidentiary hearing, and are approved in a final order or (preferably) a rule.

17. The Florida PSC Staff should present in the evidentiary hearing an evaluation report on the results that includes the following:

A. Clear and Measurable Performance Metrics: Metrics which can be provided by the utilities and incorporated into annual fuel cost adjustment proceedings.

B. Electric AOM Structure: A new electric AOM Structure which provides net economic benefits to Florida ratepayers and align with ratepayer benefits.

C. Rewards and Penalties: The electric AOM programs should recognize upside risks as well as upside benefits and include an adjustment to the utilities return on equity ("ROE") based on net reduction of risk and increase in shareholder rewards that is traditionally provided through the ROE.

D. Transparency and Verifiability: Regulators and stakeholders should be able to independently verify inputs, assumptions, and outcomes.

E. Rigorous Monitoring and Ongoing Evaluation: The total customer benefits produced by an incentive mechanism should exceed its total costs.

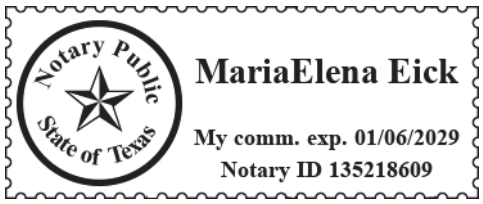
F. Compensation for Extraordinary Effort: The electric AOM Programs should not reward utilities for actions that represent normal, prudent utility behavior. Incentives should be earned for engaging in activities that provide true ratepayer benefits as a result of utility actions.

FURTHER YOUR AFFIANT SAYETH NAUGHT.

Richard A. Polich, P.E.

STATE OF TEXAS

COUNTY OF DALLAS
Signed or attested before me on April 10th, 2026, by Richard A. Polich.



MariaElena Eick
Digitally signed by MariaElena Eick
Date: 2026.04.10 08:38:57 -05'00'

(Signature of notarial officer)

Notary Public, State of Texas

Title (and Rank)

My commission expires: __01/06/2029

Exhibit 2

C.V. of

Richard A. Polich

EDUCATION

Master of Business Administration, University of Michigan, 1990
Bachelor of Science, Mechanical Engineering, University of Michigan, 1979
Bachelor of Science, Nuclear Engineering, University of Michigan, 1979

ENGINEERING REGISTRATION

Professional Engineer in the State of Michigan

PROFESSIONAL MEMBERSHIP

National Society of Professional Engineers
American Nuclear Society
American Society of Mechanical Engineers
Association of Energy Engineers Senior Member

PROFESSIONAL EXPERIENCE

Mr. Polich has more than 30 years' experience as an energy industry engineer, manager, and leader, combining his business and technical expertise in the management of governmental, industrial and utility projects. He has worked extensively in nuclear, coal, IGCC, natural gas, green/renewable generation. Mr. Polich has developed generation projects in wind, solar, and biomass in Australia, Canada, Caribbean, South American and United States. His generation experience includes engineering of systems and providing engineering support of plant operations. Notable projects include the Midland Nuclear Project and its conversion to natural gas combined cycle, start-up testing support for Consumers' coal-fired Campbell 3, Palisades nuclear steam engineering support, Covert Generating Station feasibility evaluation, and a Lake Erie offshore wind project. He also has extensive experience in utility rates and regulation, having managed Consumers Energy's rates group for a number of years. In that function his responsibilities included load and revenue forecasting, overseeing the design of gas and electric rates and testifying in regulatory proceedings. Mr. Polich has testified in over thirty regulatory and legislative proceedings.

Mr. Polich has been involved in the nuclear industry since 1978. He was hired as part of the design engineering team for the Erie Nuclear Plant by the design engineering firm, Gilbert Commonwealth. Key responsibilities was the design of systems and component specifications associated with the nuclear steam supply systems (NSSS) and steam turbine thermal cycle. Worked directly with Babcock and Wilcox on NSSS design and ancillary system specifications. Mr. Polich was also senior engineer on the Midland Nuclear project, responsible for oversight of Bechtel design engineering and interfacing with NSSS vendor Babcock & Wilcox on ancillary systems. His responsibilities also included negotiation with the Nuclear Regulatory Commission on new regulation requirements. Mr. Polich's role evolved into onsite engineering as a project trouble shooter.

SPECIFIC PROJECT EXPERIENCE

NATURAL GAS COMBINED CYCLE EXPERIENCE

Consumers Energy – 1,560 MW Midland Cogeneration Venture
Member of a small team selected to investigate the feasibility of converting the mothballed Midland Nuclear Plant into a fossil fueled power plant. Established new plant configuration that repowered the existing nuclear steam turbine with natural gas fired combustion turbines and heat recovery steam generators. Developed the new thermal cycle and heat rate, determined how to supply steam to Dow chemical for cogeneration, developed models for projecting plant performance, defined which portions of the nuclear plant were useful in the new combined cycle plant and forecasted project economics.

Nordic Energy – (2) 1,150 MW IGCC Projects

Project Manager for the development of two IGCC projects proposed to Georgia Power and Xcel Energy in response to RFPs. Responsibilities included establishing thermal cycles, equipment selection, site selection, supervising engineering, developing project proforma and proposals.

Nordic Energy – 230 MW Power Barge

This unit was to be located on the Columbia River near Portland Oregon. Lead the project development team responsible for securing equipment, designing the power plant, design of barges, assessing site feasibility, developing project economics and interconnection applications.

Teekay Corporation – Gas to Wires Project

Feasibility study for the development of ship mounted gas turbine power units (including combined cycle) to be fueled with LNG. Performed research into power station configuration, on-ship LNG storage, LNG fuel transfer stations and project economics.

RENEWABLE ENERGY EXPERIENCE

Matinee Energy – Utility Scale Solar Developer

Engineering design and project development consultant for utility scale solar photovoltaic projects. Development activities include site selection, equipment specifications, financial analysis and preparation of proposals. Also responsible for engineering and securing electrical interconnection.

Windlab Developments USA – Wind Power Developer

Responsible for greenfield development of the US platform for wind energy projects east of the Mississippi. Developed the company's engineering protocol for wind project design and construction, responsible for managing engineering design and construction of projects, and established six wind power projects (750 MW). Responsible for negation of Power Purchase Agreements, electrical interconnection studies, interface with Midwest ISO and submitting Generation Interconnection Application.

TradeWind Energy - Wind Power Project Developer

Project developer for 800 MW of wind power projects in Michigan and Indiana. Introduced new project management methods to the development process which resulted in savings of over $200,000 annually on each project.

Third Planet Windpower – Wind Power Project Developer

Engineering and project management consultant to support the startup of new wind power company. Established engineering standards used for selection of wind project equipment and project construction, analysis tools for evaluating projecting wind project power production, and performed project economic modeling.

Noble Environmental Power – Wind Power Project Developer

Electric transmission system consultant on the development of several wind power projects. Supported Noble's decisions on transmission gird interconnect and negotiate interconnection agreements.

ENERGY EFFICIENCY EXPERINCE

Arkansas Energy Office – Weatherization Assistance Program Evaluation

Evaluated the performance and operations of Arkansas's Weatherization Assistance Program. This included review of program effectiveness, program operations, energy efficiencies attained, adequacy of energy efficiency measures and subcontractor performance.

CLEAResult – Arkansas Energy Efficiency Programs

Energy efficiency operations and program support for 400% increase in Arkansas energy efficiency programs. Developed processes for data collection, field staff deployment and job assignments.

ECONOMIC IMPACT ASSESSMENT

Michigan Department of Environmental Quality - Economic Impacts of a Renewable Portfolio Standard and Energy Efficiency Program for Michigan

Project Manager for this report which focused on the economic impact of renewable portfolio standard and energy efficiency programs on the State of Michigan. The evaluation sued in this report encompassed using integrated resource planning models, econometric modeling and electric pricing models for the entire State of Michigan.

West Michigan Business Alliance - Alternative and Renewable Energy Cluster Analysis

Prepared the report provided a road map for Western Michigan businesses to establish new business in the renewable energy industry.

POWER PURCHASING AND TRADING

Nordice Energy LLC - Vice President

Established an innovative energy trading floor, created customer metering and billing systems that enabled Nordic to be the first non-utility company to supply electricity to retail customers in Michigan.

RATES & REGULATORY

Consumers Energy - Supervisor of Pricing and Forecasting

Managed the group responsible for setting and obtaining regulatory approval for the company's electric and gas rates. Developed new approaches to electric and natural gas competitive pricing, redesigned electric rates to simplify rates and eliminate losses and defined new strategies for customer energy pricing. Negotiated new electric supply contracts with key industrial electric customers resulting in over $800M in annual revenue.

EOS Energy Options & Solutions – Consulting Company

Provided testimony for multiple clients in both Detroit Edison and Consumers Energy in over 30 regulatory proceedings. Testimony topics included rates, public policy and deregulation. Also testified in several legislative proceedings in both Michigan and Ohio, addressing energy policy. Provided expert witness testimony in Massachusetts regarding wind energy projects.

POWER PROJECT EXPERIENCE:

Detroit Edison St Clair Power Station – Performed coal combustion analysis associated with conversion Powder River Basin coal. Work included pulverizer mill performance testing, boiler combustion analysis on

new coal, and unit performance analysis.

Consumers Energy Campbell 3 - Supported start-up efforts of this 800 MW pulverized coal power plant. Part of team that performed analysis of boiler data and determined the cause of superheater failure. Also part of team to analyze performance test data for warranty evaluation.

Consumers Energy Weadock Plant – Design oversight and specified various plant upgrades during major maintenance outage. Included replacement of high pressure superheater, design of new steam supply pipes, valve specifications and supported plant restart.

Consumers Energy Midland Cogeneration Venture – Part of team to assess and develop design for converting nuclear plant to gas combined cycle project. This included researching and developing scenarios for project funding and regulatory approach Primary responsibilities included:

- Developing new thermal cycle that best utilized existing steam turbine and supply steam to Dow Chemical.
- Determining which existing assets could be utilized in new plant and determining the original construction value of these assets.

NUCLEAR PROJECT EXPEREINCE

Consumers Energy Midland Nuclear Plant – Responsible for overseeing EPC contractor design and construction of primary and secondary nuclear systems. Included review of systems for compliance with Nuclear Regulatory Commission regulations. Key projects included:

- Leading team to analyze plant and determine best methods for compliance with new CFR Appendix R Fire Protection rules
- Design of primary cooling system pump oil collection and disposal systems.
- Oversight of redesign of component cooling water systems.
- Analysis of diesel generator capability to meet emergency shutdown power requirements.
- Primary interface with Dow Chemical for steam supply contract.

Ohio Edison Company Erie Nuclear Project – Design engineer responsible for the design, equipment specifications, bid evaluations and regulatory licensing for nuclear steam supply system and ancillary systems. Key projects included:

- Project Thermal Analysis
- Development of NSS valve specifications
- Major equipment bid Proposal Evaluation and recommendations
- Interface with Babcock & Wilcox on NSSS Design

REGULATORY AND LEGISLATIVE EXPERIENCE

Consumers Energy Manager of Rates – Responsible for managing rate design team, forecasting annual sales and revenue forecast and developing regulatory strategies. Testified in several state and federal regulatory proceedings.

PAPERS & PUBLICATIONS

Engineering and Economic Evaluation of Offshore Wind Plant Performance and Cost Data, 2011, Produced for the Electric Power Research Institute, KEMA, Inc.

FERC's 15% Fast Track Screening Criterion, 2012, Paper reviewing the FERC 15% screening criteria for electrical interconnection, KEMA, Inc.

Island of Saint Maarten Sustainable Energy Study, 2012, Produced for the Cabinet of Ministry VROMI, KEMA Inc.

A Study of Economic Impacts from the Implementation of a Renewable Portfolio Standard and an Energy Efficiency Program in Michigan, 2007, Produced for the Michigan Department of Environmental Quality

Alternative and Renewable Energy Cluster Analysis, 2007, Produced for the West Michigan Strategic Alliance and The Right Place

COURSES & SEMINARS

Association of Energy Engineers – Certified Energy Manager
Green Building Council – Associated LEED Certification Training
CLEAResult Leadership Academy

COMMUNITY SERVICE AND ACTIVITIES

Bicycling, hiking and cross-country skiing
Instrument-Rated Private Pilot
Habitat for Humanity
Scoutmaster
Soccer coach and referee
Volunteer work for disaster relief and building homes in Mexico

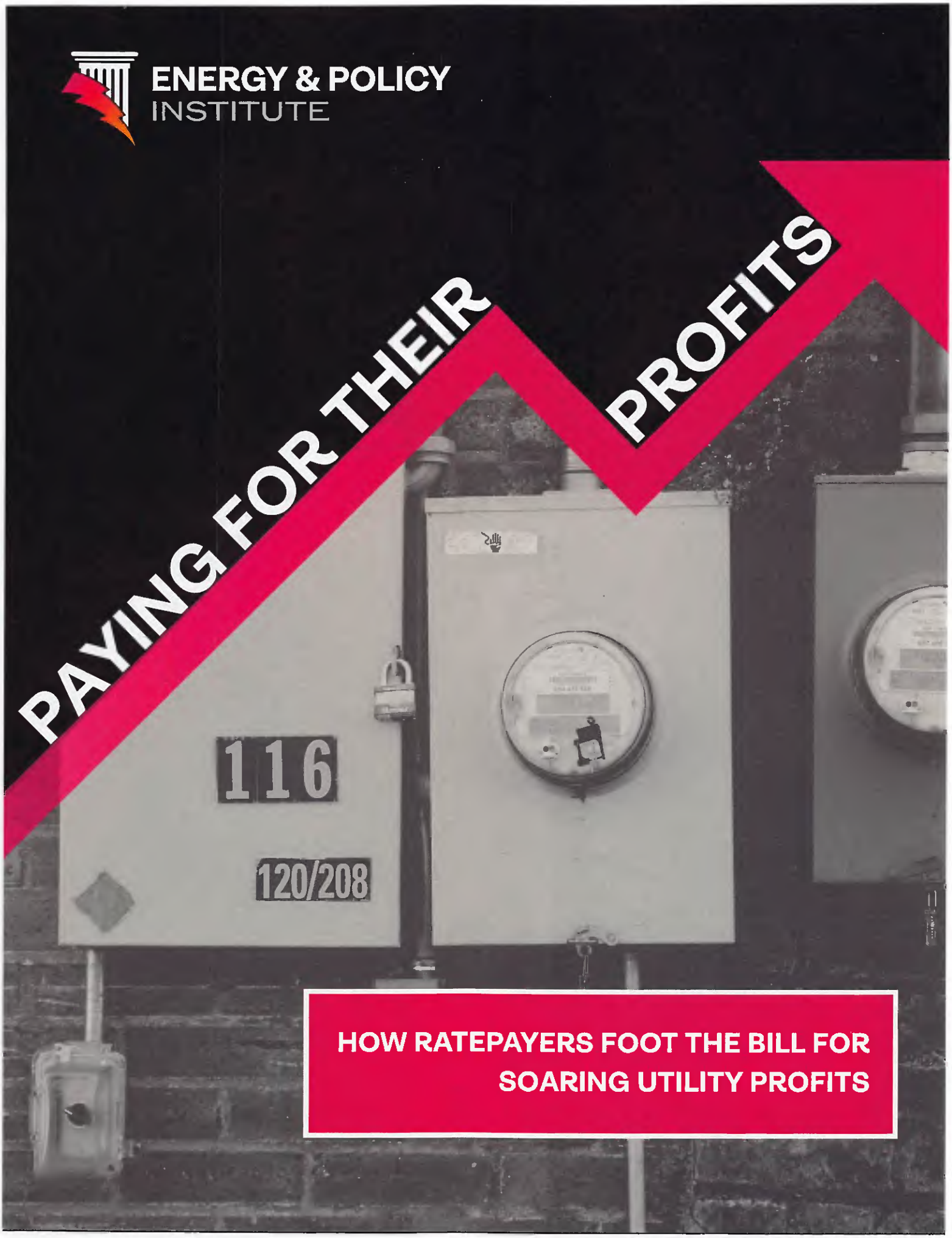
Appendix A

Paying For Their Profits

(Energy & Policy Institute)

ENERGY & POLICY INSTITUTE

PAYING FOR THEIR PROFITS



HOW RATEPAYERS FOOT THE BILL FOR SOARING UTILITY PROFITS

Paying for Their Profits: How Ratepayers Foot the Bill for Soaring Utility Profits

March 2026

Authored by

Daniel Tait, Sue Sturgis, and Shelby Green

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EXECUTIVE SUMMARY

Households and businesses served by investor-owned utilities pay billions of dollars in profits to utility investors each year. Until now, no one has put a precise number on how much of an electric bill is made up of that profit. Using publicly reported financial data, this report provides the first systematic look at how much of each dollar spent on electricity ultimately goes to investors.

EPI analyzed financial data from 110 investor-owned operating electric utilities nationwide between 2021 and 2024, including several utilities that bill customers jointly for electric and gas service. We also incorporated 2025 filings for 79 investor-owned utilities that had reported annual results to the SEC in time for inclusion in this analysis.

EPI also developed a calculator that will allow customers to discover how much of their monthly utility bill goes directly to profits. Electric utilities kept about 15 cents of every dollar they collected as profit last year. For a customer paying a $200 monthly electric bill, that means roughly $30 went to corporate profits. This profit share has been rising, up from around 13% on average between 2021 and 2024, as further detailed in this analysis.

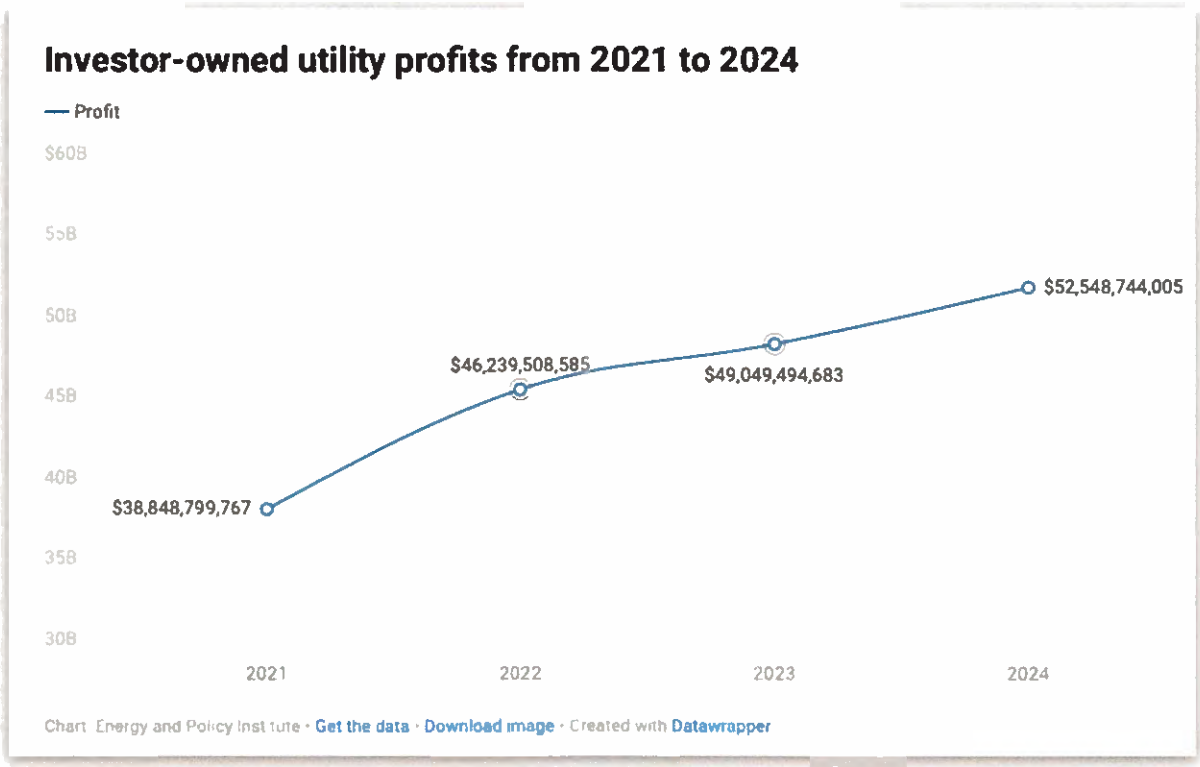

Figure 1. Investor-owned utility profits from 2021 to 2024

Key findings include:

- From 2021 through the latest available 2025 filings, the electric utilities examined in this report collected more than $200 billion in net income — profit drawn from electricity revenue collected by those utilities. Between 2021 and 2024 alone, those utilities reported approximately $186 billion in profit.
- Over the same four-year span, utilities retained an average of 12.8 percent of their revenue as profit. This means that the utilities examined in this report kept about 13 cents of every dollar customers paid as profit.
- Preliminary 2025 data (covering about three-quarters of the target utilities) show margins running even higher, with an average of 14.6 percent among reporting utilities, suggesting profit shares remain elevated.
- Some utilities consistently operate at significantly higher margins than the average. The top 10 utilities by average margin over 2021–2024 include MidAmerican Energy (27.22%), Florida Power & Light (23.51%), Nantucket Electric (23.24%), Empire District Electric (22.45%), Florida Public Utilities (20.35%), CalPeco (20.28%), Public Service Electric & Gas (19.44%), Duke Energy Carolinas (19.07%), Alabama Power (18.71%), and AEP Texas (18.63%).
- Among the 79 utilities reporting 2025 results as of this analysis, the highest margins were seen at FPL (27.44%), MidAmerican Energy (27.16%), SoCal Edison (26.11%), Georgia Power (22.57%), and AEP Texas (22.19%).
- Profit margins vary regionally. In particular, utilities in the Southeast that operate outside of organized wholesale power markets – meaning they are predominantly vertically integrated, serve captive retail customers, and do not participate in multi-state markets – reported average margins of nearly 16 percent from 2021 through 2024. This stands in contrast to lower average margins for utilities in markets such as PJM (11.8 percent) and regions in New York and New England.

These patterns suggest that a substantial share of what customers pay for electricity is consistently flowing to investors as profit, a finding that is especially significant as consumers face persistently high energy costs and financial stress.

About 30 percent of the country's electricity is sold by non-profit utilities, most of which are either cooperatives or municipally owned. Those utilities do not collect profit, and typically charge lower rates.

INTRODUCTION

Electricity bills are rising across much of the United States, placing growing pressure on household budgets and drawing increased attention from policymakers. Customers served by investor-owned electric utilities (IOUs) in many states have experienced sharp increases in what they pay for power in recent years. These increases come at a time when many families are already struggling with the rising costs of housing, food, healthcare, and other essentials, making electricity affordability an increasingly urgent concern.

In response, regulators and elected officials across the country are facing mounting pressure to explain why power bills are climbing and what can be done to bring them down. State utility commissions have seen elevated levels of rate cases and fuel cost adjustment filings in recent years, while lawmakers in several states have held hearings or introduced legislation aimed at addressing rising electricity costs.[1]

Governors have also begun publicly questioning the drivers of higher bills as customer complaints mount. In Pennsylvania, for example, Gov. Josh Shapiro has pushed for changes to regional electricity market rules and greater scrutiny of utility profits after warning that current market structures could impose billions of dollars in additional costs on consumers.[2] Amid concerns about skyrocketing electricity bills in Illinois, Gov. JB Pritzker championed legislation that aims to curb costs.[3,4] And Indiana passed bipartisan energy legislation aimed to change utilities' profit incentives.[5]

Utilities and policymakers often point to a variety of factors behind rising electricity bills. Methane (natural) gas prices have fluctuated in recent years, increasing the cost of generating electricity in some regions. Utilities are also investing billions of dollars in new infrastructure, including transmission lines, grid modernization projects, and power plants, costs that are typically recovered from customers through rates. At the same time, extreme weather events and changing energy markets have created new pressures on utilities to rebuild or harden infrastructure.

These explanations capture part of the picture. But one factor that is rarely examined closely in public discussions of rising electricity bills is utility profits.

Investor-owned utilities typically operate as regulated monopolies within defined service territories, where customers cannot choose another provider and state regulators approve the rates utilities charge. Those rates are designed not only to cover the costs of operating the electric system but also to provide utilities with a return on investment for shareholders. In other words, a portion of every electric bill ultimately goes to investors.

Despite its central role in the utility business model, the share of electricity revenue that utilities retain as profit is rarely analyzed across the industry in a systematic way.

This report provides a nationwide look at utility profit margins using publicly reported financial data from operating electric utilities. By examining how much of utilities' revenue ultimately becomes profit, the analysis offers a clearer picture of the role investor returns play in the economics of electricity service.

EPI analyzed financial data from 110 operating electric utilities across the United States between 2021 and 2024, including several utilities that provide both electric and gas service. We also examined 2025 filings for 79 utilities that had reported annual results in time to be included in this analysis.

The findings reveal that utilities consistently retain a substantial share of the revenue they collect from customers as profit, and that those margins have increased as electricity bills have risen.

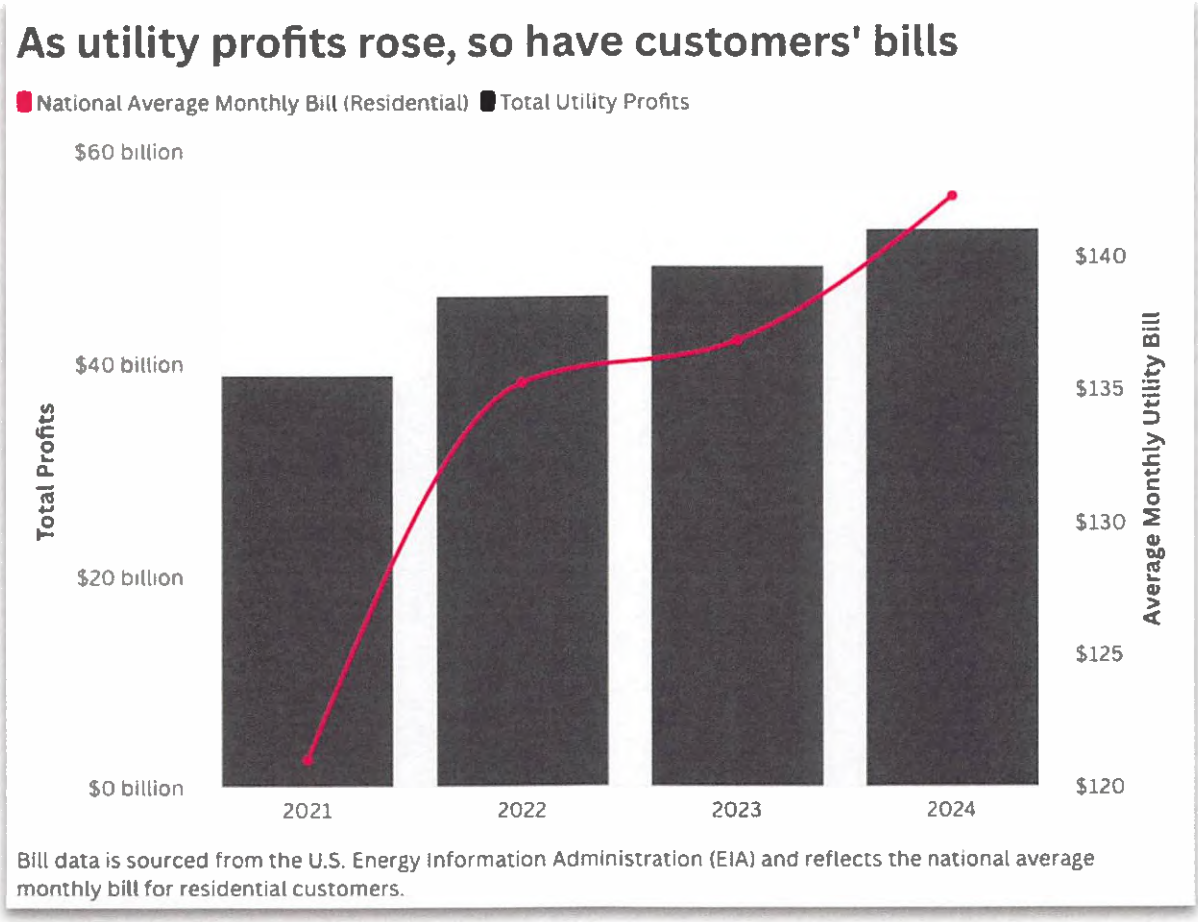

Figure 2: Profits rise as customer bills increase

The sections that follow examine these profit margins across the industry, identify the utilities with the highest profit shares, and explore how profitability varies across regions of the United States.

SECTION 1: HOW UTILITY PROFITS WORK

Understanding how investor-owned utilities earn profits and why those profits show up in customer bills requires a brief look at the regulatory framework that governs the industry.

The Regulatory Model

The electric utility business model in most of the country rests on a government-granted monopoly. Private companies receive exclusive service territories, eliminating competition and guaranteeing a customer base, under the theory that electricity infrastructure is most efficiently built once, by a single entity. The trade-off, in theory, is that those companies submit to rate regulation that prevents them from exploiting their market power. State public utility commissions (PUCs) conduct that oversight, reviewing utility costs and setting the rates customers pay. The system is designed to hold utility profits to a level that fairly compensates investors without extracting more from captive customers than service actually costs.

That rate-setting process is known as a rate case. When a utility seeks to raise its rates, or when regulators require a periodic review, the utility files extensive financial documents with the PUC laying out its costs and making the case for the revenue it says it needs to serve customers and provide a return to investors. Regulators review those filings, often over months of proceedings that include testimony from utility witnesses, commission staff, independent experts, and consumer advocates. At the end, the commission issues an order setting rates that will remain in effect until the next rate case is decided.

Rate of Return and Return on Equity

Central to any rate case is the question of how much profit the utility should be allowed to earn. Commissions determine this through two related concepts: the allowed rate of return (ROR) and the allowed return on equity (ROE).

A utility's capital structure consists of two types of financing: debt (bonds and loans) and equity (capital contributed by shareholders). The rate of return is the blended, weighted average cost of those two sources of capital — essentially, what the utility is expected to earn across its entire invested capital base, which regulators call the rate base. Because debt is less expensive than equity, and because regulators allow utilities to earn a return on equity as profit for shareholders, the allowed ROE is typically higher than the overall rate of return.

PUCs set allowed ROEs by examining what investors could expect to earn from investments of comparable risk. That standard has a long legal pedigree: the principle that a utility's rate of return should equal its actual cost of capital — no more, no less — traces back to a

concurring opinion by Supreme Court Justice Louis Brandeis in 1923 and was formally adopted by the full Court in its landmark 1944 Hope Natural Gas decision.[6] Under this standard, a return above the cost of capital is not "just and reasonable." It is, as the Court framed it, an unjust enrichment of investors at the expense of customers.

While a utility's cost of debt is straightforward to determine — it's the interest rate lenders charge — its cost of equity is not directly observable. It has to be estimated, using financial models that are contested and that critics argue consistently produce inflated results. Because a utility's stock market value scales directly with the gap between its authorized ROE and its actual cost of equity, utilities have an incentive to push for ROEs as high as possible. They devote substantial legal and financial resources to doing exactly that in rate proceedings.

The evidence suggests they've been winning that argument for decades. Utility stocks have traded at roughly twice their book value for the better part of the last 15 years — a signal that authorized ROEs are approximately twice what utilities' actual cost of equity would justify. Wall Street long-term return forecasts offer a separate benchmark: in 2024, the average authorized ROE for regulated U.S. utilities was 9.7%, while the average of 34 major investment firms' long-term equity return forecasts for the broad U.S. market was 6.7%.[7] Even the highest individual forecast — 8.3% — was lower than the average authorized utility ROE. That gap is particularly striking because utilities, with their regulated monopoly status and predictable earnings, are lower-risk investments than the market as a whole; their cost of equity should be below the market average, not above it.

One recent analysis from the American Economic Liberties Project estimated that excess ROEs cost customers approximately $50 billion per year, or roughly $300 per household annually.[8] That is money ratepayers are paying not for electricity, not for infrastructure, but for profits that exceed what investors need to be fairly compensated for providing capital.

Why Bill Profit Share Is Different from ROE

A key concept for understanding this report is that the profit in a customer's bill is not the same number as the utility's allowed ROE. They measure fundamentally different things, and understanding why requires thinking not just about percentages, but about time.

ROE describes what percentage of shareholders' invested capital they earn as profit. How much of a customer's bill is profit describes what fraction of each dollar collected from customers ends up as profit for the utility.

The profit share of a customer's bill is typically higher than the authorized ROE, not lower. ROE is earned on shareholder equity invested in the rate base. For capital-intensive utilities, that equity base is usually larger than the revenue collected from customers in any single

year. If a 10% return is applied to an equity base larger than annual customer revenue, the profit portion of a customer's bill will exceed 10%. The ROE levels that dominate rate case debates are therefore not the ceiling on how much of a customer's bill goes to profit.

A second, equally important dimension: what an annual ROE costs customers over the decades-long life of utility infrastructure.

Consider a home mortgage. A 5% interest rate on a home mortgage sounds reasonable. But a homebuyer who finances a $300,000 mortgage at 5% over 30 years will make total payments of roughly $580,000: the $300,000 they borrowed, plus nearly $280,000 in interest. By the end of the 30-year term, the homebuyer has paid close to twice what they originally borrowed. What may have seemed like a modest interest rate ballooned into a much larger cumulative cost, and profit to the bank.

The same dynamic operates in utility ratemaking. When a utility builds a new power plant, it doesn't recover that cost all at once. The asset is placed in the rate base and depreciated over its useful life, often 30 years or more. Each year, customers pay back a slice of the original investment through depreciation. But they also pay a return on whatever asset value remains in the rate base. As the asset depreciates, the annual return shrinks, but it does not stop until the asset is paid off. Year after year, customers are paying a return on a declining but not-zero balance, until the plant is fully paid off.

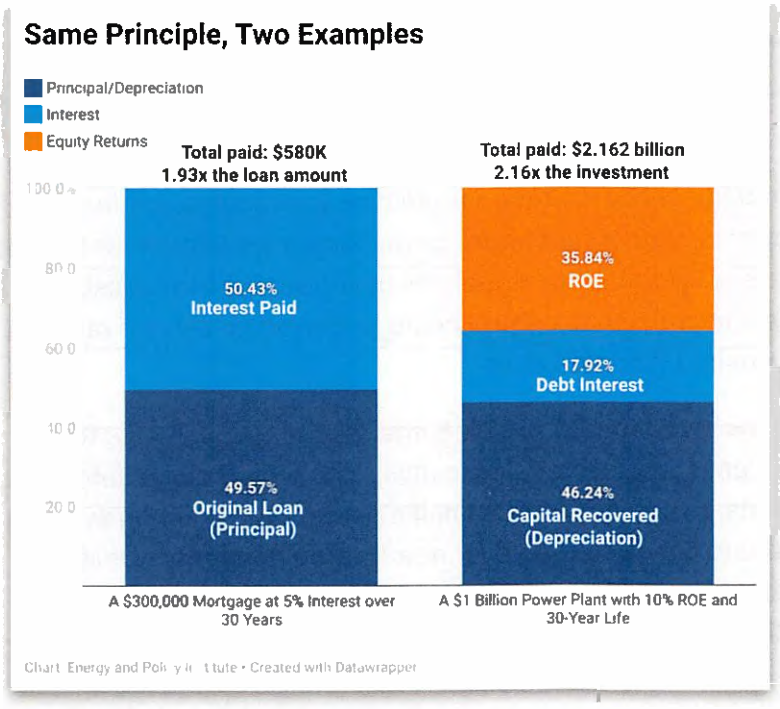

Figure 3. How the cost of equity and debt adds costs to a project

On a $1 billion power plant financed with equal shares of debt and equity — using an example 10% ROE and 5% debt rate over 30 years — customers would pay roughly $775 million in profits to shareholders alone, on top of the full $1 billion in capital recovery. Add in debt interest, and total customer payments for that single asset approach $2.2 billion. A $1 billion investment, paid for more than twice over. Figure 3 illustrates how this parallels what happens with a mortgage.

Utilities are perpetually adding new assets to the rate base. Old assets depreciate off the rate base while new ones are added, keeping the total balance, and the annual return payments, persistently high. The cumulative profit extracted from customers across a utility's entire infrastructure portfolio, year after year, is what makes the profit share of the electric bill so consequential.

How Profits Are Set by Policy and What Policymakers Can Do

The profit share embedded in an electric bill is not a natural phenomenon. About 30 percent of the country's electricity is sold by non-profit utilities, most of which are either cooperatives or municipally owned. Profit levels are the product of policy decisions made by state utility commissions, typically in contested rate proceedings, using methodologies that have evolved over decades. That means they can be changed.

Policymakers and regulators have several tools available:

- **Lower allowed ROEs.** Return on equity benchmarks are set case by case, and commissions have great discretion. States that adopt more conservative benchmarks, better calibrated to current market conditions, reduce the profit margin embedded in customer bills. States can enact new legislation or use existing regulatory authority to lower ROEs.[9]

- **Scrutinize capital structure assumptions.** The mix of debt and equity in a utility's capital structure affects the overall rate of return. Commissions that push back on utilities seeking to hold more equity, which earns a higher return, can reduce allowed profits.

- **Reform ratemaking.** Traditional rate-of-return regulation guarantees utilities a profit regardless of efficiency or customer outcomes. Some states are experimenting with performance-based ratemaking structures that link utility earnings to measurable results, which may create incentives to control costs and improve service rather than simply building more into the rate base.

- **Strengthen consumer advocacy in rate proceedings.** Research has found that states with independent consumer advocates in utility rate proceedings authorized meaningfully lower returns on equity by almost half a percentage point on average across more than 1,600 rate cases studied over nearly three decades.[10] Utilities arrive with large legal and financial teams; residential customers rarely have equivalent representation without a funded advocate.

SECTION 2: WHAT THE DATA SHOW ABOUT UTILITY PROFIT MARGINS

To better understand how profits fit into the economics of electricity service, EPI analyzed publicly reported financial data from operating electric utilities across the United States. The analysis examined financial disclosures from 110 investor-owned electric utilities between 2021 and 2024, as well as 2025 filings available for 79 utilities that had reported results in time to be included in this report.

Investor-owned utility profits for 2024

	Utility	State (HQ)	Profit	Profit Portion of Customer Bill
1	Florida Power & Light	FL	$4,543 million	27%
2	Pacific Gas & Electric Co.	CA	$2,712 million	11%
3	Georgia Power	GA	$2,543 million	22%
4	Virginia Power	VA	$1,897 million	19%
5	Duke Energy Carolinas	NC	$1,883 million	19%
6	Xcel (electric subsidiaries)	MN	$1,846 million	17%
7	SoCalEdison	CA	$1,794 million	10%
8	Consolidated Edison Company of New York	NY	$1,748 million	12%
9	Public Service Electric & Gas	NJ	$1,547 million	18%
10	Alabama Power	AL	$1,403 million	19%

Additional 100 rows not shown

** Data from FERC Form 1, instead of SEC 10-K data
*** Reports end of fiscal year, instead of calendar year
**** Bought by private equity in 2025 so no longer reports to the SEC

Table: Energy and Policy Institute • Created with Datawrapper

Figure 4. Investor-owned utility profits for 2024

The results show that utilities consistently retain a substantial share of the revenue they collect from customers as profit, and that these profit levels have risen in recent years.

Utility profit margins averaged nearly 13 percent from 2021 to 2024

Across the utilities examined in this report, the median profit margin between 2021 and 2024 was 12.9 percent. In other words, utilities retained about 13 cents of every dollar in revenue as profit during this four-year period.

The average profit margin was nearly identical at 12.8 percent, indicating that the results are broadly representative of the sector and are not driven by a handful of unusually high-profit utilities. These figures reflect sustained trends over multiple years rather than one-time spikes.

In total, the utilities examined in this report reported almost $186 billion in profit between 2021 and 2024.

Profit margins of this scale are high relative to most sectors of the U.S. economy. Companies in most industries typically report net profit margins in the single digits, making the margins reported by many electric utilities comparatively large.[11]

Many utilities report substantially higher profit shares

While the industry average margin was 12.8 percent, many utilities reported profit shares well above that level.

Between 2021 and 2024, nearly 40 utilities averaged profit margins above 15 percent, meaning they retained more than 15 cents of every revenue dollar as profit.

Some utilities reported even higher margins. The utilities with the highest average profit shares over the four-year period were:

- MidAmerican Energy – 27.22%
- Florida Power & Light (FPL) – 23.51%
- Nantucket Electric – 23.24%
- Empire District Electric – 22.45%
- Florida Public Utilities – 20.35%
- CalPeco – 20.28%
- Public Service Electric & Gas – 19.44%
- Duke Energy Carolinas – 19.07%
- Alabama Power – 18.71%
- AEP Texas – 18.63%

Several of these utilities sustained profit margins above 20 percent for multiple years during the period analyzed.

Early 2025 data show profit margins running higher

Available 2025 filings covering 79 utilities suggest that profit margins are currently running higher than the four-year average.

Investor-owned utility profits for 2025

	Utility	State (HQ)	Profit	Profit Portion of Customer Bill
1	SoCalEdison	CA	$5,033 million	26%
2	Florida Power & Light	FL	$5,012 million	27%
3	Pacific Gas & Electric Co.	CA	$3,079 million	12%
4	Georgia Power	GA	$2,851 million	23%
5	Duke Energy Carolinas	NC	$2,108 million	22%
6	Virginia Power	VA	$2,101 million	18%
7	Consolidated Edison Company of New York	NY	$1,906 million	12%
8	Xcel (electric subsidiaries)	MN	$1,870 million	15%
9	Public Service Electric & Gas	NJ	$1,745 million	18%
10	Alabama Power	AL	$1,516 million	18%

Additional 69 rows not shown

** Data from FERC Form 1, instead of SEC 10-K data
*** Reports end of fiscal year, instead of calendar year
**** Bought by private equity in 2025 so no longer reports to the SEC

Table: Energy and Policy Institute · Created with Datawrapper

Figure 5. Investor-owned utility profits for 2025

Among these utilities, the median profit margin was almost 15 percent, while the average was approximately 14.6 percent.

While these results are preliminary and do not yet include all of the investor-owned utilities, they suggest that profit shares have increased over the average levels observed between 2021 and 2024.

Among the utilities reporting the highest profit margins so far in 2025 were:

- Florida Power & Light – 27.44%
- MidAmerican Energy – 27.16%

- Southern California Edison – 26.11%
- Georgia Power – 22.57%
- AEP Texas – 22.19%

Profit margins vary significantly by region

The analysis also found notable regional differences in utility profit margins.

Utilities in the Southeast that operate outside of organized wholesale electricity markets reported the highest average profit shares. Between 2021 and 2024, these utilities retained nearly 16 percent of revenue as profit.

By contrast, utilities operating within organized electricity markets reported significantly lower margins. For example, utilities in the PJM regional market serving the Mid-Atlantic averaged about 11.8 percent, while utilities in New York and New England reported similar or lower levels.

These regional differences reflect, in part, how electricity markets are structured. In the Southeast, where utilities are typically vertically integrated, a single company owns generation, transmission, and distribution — meaning the profit margin captured in this analysis reflects all of utility earnings that flow through customer bills. In competitive wholesale

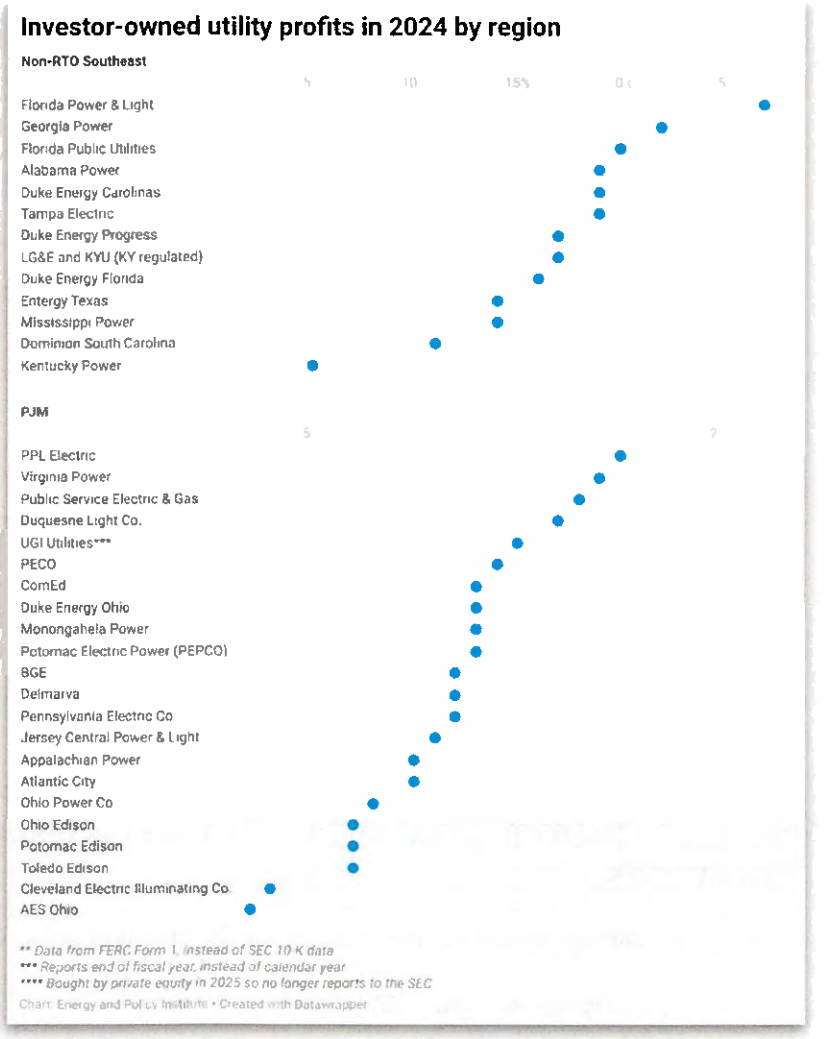

Figure 6. Investor-owned profits, Southeast and PJM

markets like PJM, there are local regulated utilities that own only transmission and distribution; generation is often owned by independent power producers whose earnings are not captured by this analysis.

Lower margins in competitive markets do not by themselves indicate better overall outcomes for customers — PJM's data center boom, failure to interconnect new generation, and capacity market shortfalls have led to soaring prices for customers, for example — but the gap between Southeastern utilities and their counterparts in competitive markets is large enough to warrant scrutiny of whether vertically integrated monopolies operating outside of RTOs are consistently extracting more profit from captive customers than is necessary to provide safe and reliable electricity service.

SECTION 3: METHODOLOGY

EPI collected financial data for 110 investor-owned electric utilities providing service in the United States for the years 2021 through 2024, and for 79 utilities that reported 2025 results to the SEC in time for inclusion in this analysis.

Data Sources

The data we reviewed for this report comes from the investor-owned utilities. We used U.S. Securities and Exchange Commission filings, specifically 10-K annual reports, as our primary data source where available. SEC filings are standardized, audited, and publicly accessible, making them the most reliable basis for this type of analysis.

Where a 10-K did not have the required data, we used data from the utility's Form 1 filing to the Federal Energy Regulatory Commission. The Form 1 is an annual financial report that all utilities meeting applicable size thresholds are required to submit to FERC, and it provides operating company-level detail that some consolidated SEC filings may obscure or that some utilities are not required to file. For instance, some utilities are owned by parent companies based outside the United States and may not be required to file a 10-K.

We also used data from non-SEC financial reports that one major company, FirstEnergy, publishes to its website for each of its utilities.

Utilities owned or acquired by private equity or foreign holding companies may have limited or no SEC filing data for recent years.

Scope

This analysis covers investor-owned utility operating companies only. We did not include municipal utilities, rural electric cooperatives, or other non-investor-owned entities. These organizations are fundamentally non-profit entities. They operate under fundamentally different economic and governance structures.

For utilities that provide both electric and gas service, we used electric-only financial data wherever the source material allowed for it. Where a utility bills customers jointly for electric and gas service, as is the case for PG&E in California for example, we used consolidated data reflecting the combined service. Our goal was for the data to correspond as closely as possible to the actual bills that customers pay.

Utilities that were taken private or otherwise ceased to be publicly reporting investor-owned entities during the analysis period were excluded from the dataset.

For regional comparisons, when a utility served multiple regions, we assigned it to the region where the utility is headquartered.

We reported utilities that merged, sold, or otherwise changed ownership with as much data as was available during the time-period reviewed. For example, Penn Power, West Penn Power, and Met Ed have merged with Pennsylvania Electric. Our reporting reflects each entity's standalone financials for the years in which they filed separately. Once a utility is absorbed into another entity, its data ends at the last year of independent reporting.

Calculating Bill Profit Share

To calculate the approximate percentage of a utility's customer bill that flows to investors, we divided net income by total operating revenues per year. This ratio, net income as a share of revenue, is our primary metric throughout this report. This metric does not isolate the electric portion of revenue in cases where utilities report consolidated electric and gas operations.

This is a deliberately straightforward calculation. It is not a cost-of-service analysis, and it does not purport to determine whether a given utility is earning exactly its allowed rate of return or over- or under-earning relative to that benchmark. It answers a simpler question: for every dollar this utility collected from customers, how much ended up as net income?

The net income figures in this analysis are reported after income taxes. Utilities collect enough revenue to cover both their income tax liability and their return to shareholders, meaning customers fund both. The profits reported here reflect only what utilities retain as net income after taxes are paid; they do not include the income taxes customers effectively pay on utilities' behalf. The total profit-related share of customer bills — net income plus income taxes — is higher than the figures reported here.

SECTION 4: GLOSSARY OF TERMS

Capital structure — The mix of debt (loans and bonds) and equity (shareholder investment) that a utility uses to finance its assets. The proportion of debt to equity directly affects the overall rate of return a utility earns: because equity commands a higher return than debt, utilities with more equity in their capital structure extract more profit from customer bills.

Cost of capital (COC) — The average cost a utility pays to raise money from lenders and investors to build and run its system.

Cost of equity (COE) — The return that equity investors require to provide capital to a utility, reflecting the risk of the investment. Unlike the cost of debt, which is directly observable from lenders' interest rates, the cost of equity must be estimated, a process that is methodologically contested and that critics argue has consistently produced results higher than actual market conditions warrant in recent years.

Depreciation — The portion of a utility bill that gradually repays the cost of building power plants, transmission lines, and other infrastructure over the life of those assets. Customers also pay a return each year on the remaining unpaid portion of that investment, so over time the total amount paid for an asset typically exceeds what it originally cost to build.

FERC Form 1 — An annual financial report that utilities meeting certain size thresholds must file with the Federal Energy Regulatory Commission (FERC). It provides operating-company-level financial detail that can be more granular than consolidated SEC filings, and is EPI's secondary data source where 10-K data was insufficient.

Investor-owned utility (IOU) — A privately owned, for-profit electric utility company. IOUs normally receive an exclusive geographic franchise and an obligation to serve all customers in exchange for accepting rate regulation and state oversight. They are distinguished from publicly owned utilities by their shareholder ownership and profit motive.

Just and reasonable — The legal standard governing utility rates, derived from the U.S. Constitution and codified in federal and state law. Rates that enrich investors beyond the cost of capital are not "just and reasonable" under the standard affirmed by the Supreme Court in *FPC v. Hope Natural Gas Co.* (1944).

Net income — A company's profit after all operating costs, interest payments, and taxes have been deducted from revenues. Net income is the numerator EPI uses to calculate each utility's profit margin in this report.

Operating utility — A regulated electric utility that directly provides electricity service to customers.

Parent company — A holding corporation that owns one or more utility subsidiaries.

Performance-based ratemaking — An approach to utility regulation that ties a utility's allowed earnings to specific, measurable outcomes — such as reliability, cost efficiency, or customer satisfaction — rather than guaranteeing a return on capital regardless of performance. It is intended to align utility incentives with customer interests.

Profit margin or bill profit share — Net income expressed as a percentage of total revenue for a given year. These terms are used interchangeably in this report to describe the portion of each customer dollar that the utility retains as profit rather than spending on operations, infrastructure, or debt service.

Public utility commission (PUC) — A state regulatory body responsible for overseeing investor-owned utilities, setting the rates they can charge customers, and reviewing their costs and financial performance. Also called a public service commission (PSC) or state corporation commission (SCC) in some states.

Rate base — The total net value of assets on which a utility is permitted to earn a rate of return. Typically includes power plants, transmission lines, distribution infrastructure, and other utility capital investments, minus accumulated depreciation. A larger rate base means larger annual returns collected from customers.

Rate case — A formal proceeding in which a utility requests approval from its state commission to change the rates it charges customers. Rate cases typically involve extensive financial filings and expert testimony and often unfold over months before the commission issues an order.

Rate of return (ROR) — The overall percentage return a utility is permitted to earn on its rate base, calculated as the weighted average of its cost of debt and its authorized return on equity. Sometimes called the weighted average cost of capital (WACC).

Regional transmission organization (RTO) / Independent system operator (ISO) — An independent entity that manages high-voltage transmission infrastructure and operates competitive wholesale electricity markets across multiple states.

Regulated monopoly — A market structure in which a single utility is granted exclusive service territory in exchange for oversight of its rates and operations.

Return on equity (ROE) — The authorized percentage return that a utility's equity investors earn on their invested capital, as set by regulators in rate proceedings. ROE is a component of the overall rate of return, applies only to the equity portion of the capital structure, and is set with reference to what investors could earn on comparable-risk investments elsewhere.

Rider/surcharge — An additional charge added to customer bills to recover specific costs, such as environmental compliance or infrastructure upgrades.

SEC 10-K — The annual report that publicly traded companies, including most large investor-owned utilities, are required to file with the U.S. Securities and Exchange Commission. 10-Ks include audited financial statements and are EPI's primary data source for this analysis.

Vertically integrated utility — A utility that owns and operates the full electricity supply chain: generation (power plants), transmission (high-voltage delivery), and distribution (local delivery to homes and businesses).

Wholesale electricity market — A market where electricity generators sell power to utilities or other buyers before it is delivered to retail customers.

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Appendix B

ORDER No. 12923 FPSC 296

(1984 Stockholder Sharing Order)

1984 Fla. PUC LEXIS 901

Florida Public Service Commission

January 24, 1984

DOCKET NO. 830001-EU-B; ORDER NO. 12923, 84 FPSC 296

FL Public Service Commission Decisions

Reporter
1984 Fla. PUC LEXIS 901 *

In re: Fuel Adjustment Recovery Clauses of electric utilities - treatment of gain on economy sales

Core Terms

fuel, energy, base rate, cost, revise, staff, shareholder

Purchase *Order*:

Counsel

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Panel: The following Commissioners participated in the disposition of this matter: GERALD L. GUNTER, Chairman; JOSEPH P. CRESSE, KATIE NICHOLS

Opinion

Pursuant to Notice, the Florida Public Service Commission conducted a public hearing in **[*2]** the above docket in Tallahassee, on December 15, 1983.

ORDER APPROVING TREATMENT OF GAIN ON ECONOMY SALES

BY THE COMMISSION:

Economy energy transactions represent the sale of energy between electric companies. Gains are realized by the selling company as a result of the split-the-savings methodology used to calculate the selling price of economy energy. In the past, the Commission has considered gains on electric economy energy sales between companies during each individual company's general rate proceeding. These gains were included in base rates as a reduction of expenses. By ***Order No***. 12663, in Docket ***No***. 830012-EU, we decided that it would be appropriate to review in the fuel adjustment proceedings the question of whether the gain on economy energy sales would be more appropriately treated in the fuel adjustment clause than in base rates. The present treatment which was adopted by this Commission in 1977 allows purchasing utilities to recover the total costs of economy energy purchases through the fuel adjustment clause while selling utilities deduct only the fuel component of economy energy sales from their fuel expense for fuel adjustment purposes. Through **[*3]** this procedure, purchasing utilities are made whole by allowing them to recover the total cost of economy energy purchases and the selling utilities' fuel expenses are reduced by the cost of fuel used to generate the economy energy. Because the gains are included in base rates, the selling utility may either retain gains in excess of the level included in base rates for the benefit of its shareholders or, conversely, the shareholders may suffer a loss if the gains are less than the base rate amount.

At hearing, on December 15, 1983, Staff witness, C. K. Hvostik, proposed that the treatment of a gain on economy energy sales be transferred from general rate proceedings to the fuel adjustment docket and be transferred from the base rates to the fuel and purchased power cost recovery clause. The chief reason for this proposed treatment was to eliminate the potential for over or under recovery of revenues associated with economy energy sales. In addition, the Staff witness proposed that the selling utilities be allowed to retain 20% of the economy sales profit for their shareholders and that the remaining 80% be credited to ratepayers through the fuel and purchased power cost recovery **[*4]** clause. The proposed treatment would also remove from rate cases the difficult issue of what level of economy sales profits to include in base rate. Under current rate case treatment a utility is rewarded if actual economy sales profits exceed the projected amount included in the test year and penalized if the actual economy sales are less than projected. Problems with the current treatment stem from the difficulty in projecting economy sales and the potential bias of a utility to under project their economy sales profits. The difficulty in projecting economy sales profits is due to uncertainty associated with fuel prices, weather, and forced outages of generating units and transmission lines. These variables affect not only how much a utility can sell and at what price, but also how much other utilities will buy at different prices.

Public Counsel's witness, James R. Dittmer, stated that he did not feel it was necessary or equitable to have an incentive for the utility to engage in these economy sales transactions. Gulf Power's witness proposed a 50%-50% split of the gain on economy sales. Several witnesses stated that a major problem with the current treatment is the incentive **[*5]** to predict a zero gain for economy sales in a projected test year so that shareholders could keep all of the gain realized. We agree with the testimony that projecting economy sales profits is difficult due to the uncertainty associated with fuel prices and other reasons given by the various witnesses. Without exception, the parties agree that it is appropriate to remove economy sales transactions from general rate proceedings and to include them in the proceedings dealing with fuel and purchased power cost recovery clauses. The only decision which remains to be made is whether or not we should adopt the Staff's recommended 80%-20% split, Gulf Power's 50%-50% split, or Public Counsel's suggestion of a 10% flow through of the gains to the rate payers.

We believe the Staff's witness was correct in stating that "a positive incentive will preserve current levels of economy sales and may result in increased sales and that the 20% incentive is large enough to maximize the amount of economy sales and provide a net benefit to the ratepayer. "

At the hearing we directed the Staff to develop appropriate and proper procedures for incorporating their proposal as early in the process as it **[*6]** can be done legally. The Staff, on January 10, 1984, held an informal meeting with the companies and Public Counsel in ***order*** to garner and exchange information concerning our directive. Two separate approaches were presented concerning the implementation of a procedure for the inclusion of profits realized in economy energy sales in the fuel adjustment clause. TECO and the Staff considered it appropriate at the February, 1984 fuel adjustment proceeding to revise base rates to remove economy energy sales profits and to transfer the same to the fuel adjustment clause. Others present, other than Public Counsel, considered it appropriate to wait until a utility is involved in its next general rate proceeding to revise base rates. During the interim period, however, the fuel adjustment clause would be indexed by the appropriate factor. The procedure suggested by TECO and the Staff appears to be the more desirable method because it is easier to administer and meets our goal of removing fuel and fuel-related items from base rates.

Due to our decision to include economy sales profits in the fuel adjustment clause, it is necessary to revise the minimum filing requirements **[*7]** by adding new schedules that will present the data pertaining to the profits. The two new schedules are Schedule A7a, Economy Energy Sales and Profits, and Schedule E7a, Economy Energy Sales and Profits. Scheduled A7a is to be included in the monthly filings for reporting actual transactions and Schedule E7a is to be included as a part of the filing for projection purposes. The format of the new schedules is as follows:

(1)	(2)		(3)		(4)
Sold to	**Total**		**/KWH**		**Profit($)**
	Sold	**(a)**	**(b)**	**(c)**	**(2)X(3)(c)**
		Total	**Sales**	**(3)(b)-(3)(a)**	
		Cost	**Price**	**Profit**	
Subtotal					
X80%					X80%
Amount for Fuel Adjustment					

In ***order*** to keep the revisions to a minimum, the "Amount for Fuel Adjustment" should be included as a separate line item on both Schedule A7 and Schedule E7, as appropriate.

Because of our decision to revise base rates by removing the economy sales profits, the utilities are directed to provide the dollar amount of economy sales profits included in base rates in their most recent rate case. In addition, the utilities are to provide a schedule, on a /KWH basis for each rate class, the current base KWH rate, the amount of economy sales profits **[*8]** in the base rate, and a revised base rate excluding economy sales profits. Since the prehearing conference for the upcoming fuel adjustment hearing is to be held on February 8, 1984, this data is to be filed with the Commission ***no*** later than February 3, 1984 in ***order*** to allow the Staff time to review the data and take a position at the prehearing conference.

Therefore, in consideration of the foregoing, it is

ORDERED by the Florida Public Service Commission that the economy energy sales profits are being removed from base rates and being included in fuel and purchase power cost recovery clause, effective April 1, 1984. It is further

ORDERED that the economy energy sales profits are to be divided between ratepayers and the shareholders on a 80%-20% basis, respectively. It is further

ORDERED that affected electric utilities will comply with the requirements found in the body of this ***Order***.

BY ***ORDER*** of the Florida Public Service Commission, this 24th day of January, 1984.

Order

FL Public Service Commission Decisions

End of Document

Appendix C

Order No. PSC 2000-1744-PAA-EI

(2000 Stockholder Sharing Order)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

The following Commissioners participated in the disposition of this matter:

J. TERRY DEASON, Chairman
E. LEON JACOBS, JR.
LILA A. JABER

APPEARANCES:

JAMES D. BEASLEY, Esquire, Ausley & McMullen, P. O. Box 391, Tallahassee, Florida, 32302,
On behalf of Tampa Electric Company (TECO).

JAMES A. McGEE, Esquire, P.O. Box 14042, St. Petersburg, Florida 33733-4042,
On behalf of Florida Power Corporation (FPC).

JEFFREY A. STONE, Esquire, Beggs & Lane Law Firm, 700 Blount Building, 3 West Garden Street, P.O. Box 12950, Pensacola, Florida 32576-2950,
On behalf of Gulf Power Company (Gulf).

MATTHEW M. CHILDS, Esquire, Steel Hector & Davis LLP, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301-1804,
On behalf of Florida Power & Light Company (FPL).

STEPHEN C. BURGESS, Esquire, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400.
On behalf of the Citizens of the State of Florida (OPC).

VICKI GORDON KAUFMAN, Esquire, McWhirter Reeves McGlothlin Davidson Decker Kaufman Arnold & Steen, P.A., 117 South Gadsden Street, Tallahassee, Florida 32301
On behalf of Florida Industrial Power Users Group (FIPUG).

WM. COCHRAN KEATING, IV, Esquire, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Commission Staff.

ORDER APPROVING INCENTIVE MECHANISM FOR SPECIFIED NON-SEPARATED WHOLESALE POWER SALES BY INVESTOR-OWNED ELECTRIC UTILITIES
AND
NOTICE OF PROPOSED AGENCY ACTION
ORDER ESTABLISHING METHOD FOR CALCULATION OF GAINS ON NON-SEPARATED WHOLESALE POWER SALES AND ESTABLISHING APPROPRIATE REGULATORY TREATMENT FOR REVENUES AND EXPENSES ASSOCIATED WITH NON-SEPARATED WHOLESALE POWER SALES

BY THE COMMISSION:

By Order No. 12923, issued January 24, 1984, in Docket No. 830001-EU-B, this Commission established a shareholder incentive mechanism to encourage investor-owned electric utilities (IOUs) to make economy energy sales. Prior to the issuance of Order No. 12923, in 1984, the revenues from the sale of economy energy were considered in each IOU's general rate proceeding. By Order No. 12923, this Commission removed these revenues from base rates, and credited the revenues through the Fuel and Purchased Power Cost Recovery Clause (fuel clause). At page 2 of Order No. 12923, we stated that "[t]he chief reason for this proposed treatment was to eliminate the potential for over- or under- recovery of revenues associated with economy energy sales." Further, we authorized the IOUs to keep 20 percent of the gains on these sales as an incentive to "maximize the amount of economy sales and provide a net benefit to the ratepayer." In other words, the incentive was created, in part, to encourage the IOUs to use their excess capacity to make economy sales, with 80 percent of the revenue from those sales being credited to the ratepayers.

At our November 22-23, 1999, hearing in Docket No. 990001-EI, the panel heard arguments about whether this incentive mechanism is

still necessary or appropriate. By Order No. PSC-99-2512-FOF-EI, issued December 22, 1999, a proceeding was instituted so that the full Commission could hear this matter. Accordingly, an evidentiary hearing was held on May 10, 2000, and post-hearing briefs were filed by the parties.

I. Appropriateness of Shareholder Incentives

With respect to the question of whether the incentive mechanism approved in Order No. 12923 is still necessary and appropriate, FPC witness Wieland testified that we should continue our policy of providing shareholder incentives to encourage economy sales. Further, witness Wieland testified that because these sales have shifted to more competitive markets outside of the Florida Energy Broker Network (Broker or EBN), with new non-utility participants who retain 100% of the profits, our incentive policy should be updated to reflect current market conditions. FPL argued in its brief that no disputed fact or factual showing has been identified that would sustain the burden of reversing our policy on incentives. Gulf witness Howell also testified that the current shareholder incentive should not be eliminated. Like FPC witness Wieland, witness Howell testified that because today's wholesale market is more competitive, utility economy sales are more difficult to achieve, thus increasing the importance of the incentive to encourage continued participation in the economy energy market. Along with the other IOUs' witnesses, TECO witness L. Brown testified that we should adhere to our existing policy of providing shareholder incentives to encourage non-separated, non-firm wholesale sales.[1] Witness Brown testified that these incentives may provide greater benefits to ratepayers now than when they were first adopted.

In opposition to the IOUs, FIPUG argued in its brief that the current incentive mechanism should be eliminated. FIPUG asserted that we should not provide an additional incentive, beyond the current incentive of a guaranteed return and a captive customer base, for the IOUs to perform their required managerial duties. OPC witness Dismukes also supported elimination of the current incentive. Witness Dismukes testified that factors other than the

[1]By Order No. PSC-97-0262-FOF-EI, issued March 11, 1997, we defined non-separated wholesale power sales, stating that "[h]istorically, the Commission has treated sales that are non-firm or less than one year in duration as non-separated sales."

incentive established in Order No. 12923 are serving as far stronger incentives for Florida's IOUs to maximize their wholesale sales. Further, witness Dismukes testified that the current incentive mechanism is one-sided in that it does not penalize IOUs for substandard performance and that it requires consumers to pay a second time for services for which they are already paying full costs.

The record shows that prior to the issuance of Order No. 12923, the buying and selling of economy energy was a peripheral function of the system dispatcher. Most economy energy transactions were accomplished over the Broker. After meeting their requirements for firm load, the buying and selling utilities would enter quotes determined by decremental and incremental production costs. A computer program would then match buyers and sellers with the greatest cost savings. The transaction price was based on a split-the-savings methodology. Thus, the record demonstrates that the Broker functioned essentially as a simple cost-based market for short-term excess energy within Peninsular Florida. Buyers and sellers benefitted equally from each transaction made over the Broker due to the split-the-savings pricing methodology.

The parties to this proceeding acknowledge that the wholesale market in Florida is more competitive today than when Order No. 12923 was issued. Changes to the wholesale market were prompted in part by the Public Utilities Regulatory Policy Act; the Energy Policy Act of 1992; FERC Orders 888 and 889; and other federal and state regulatory policy initiatives. These regulatory changes have resulted in a more robust wholesale market in Florida, with additional buyers and sellers. The record demonstrates that this movement toward competition has prompted additional efforts on the part of Florida's IOUs to participate in the wholesale market. For example, IOUs have substantially augmented the trained staff in their marketing departments in recent years. Further, the buying and selling of energy has now become the primary function of a specific group of employees, rather than the peripheral function of the system dispatcher.

The record shows that these increased efforts have produced results. As a whole, the data indicates that utilities have increased their presence in the wholesale market through the increased number of their non-separated wholesale transactions and the increased gains on those transactions in recent years. The record also shows that FPC, FPL, and TECO did not apply the 20

percent shareholder incentive approved in Order No. 12923 to the majority of their non-separated sales made over the last six years. FPC witness Wieland, FPL witness Stepenovitch, and TECO witness L. Brown indicated that their respective companies have interpreted the Order to provide an incentive only on their sales made under FERC Schedules C and X. Witness Stepenovitch indicated, however, that FPL recently discontinued Schedule X sales. As a result, FPC, FPL, and TECO received an incentive on sales associated with only 2.1%, 0.2%, and 6.8% of the gains for 1999, respectively. Gulf interpreted Order No. 12923 more broadly and, according to witness Howell, applied the shareholder incentive to the gains for all of its non-firm, non-separated wholesale sales.

The record indicates that this increase in gains is the result of both the increased efforts to make sales and the ability to charge market-based rates. For example, FPL witness Stepenovitch testified that FPL had increased the number of its contracts from approximately 63 to over 400 in the past three years. FPL received authority from FERC to charge market-based rates for out-of-state sales in 1998, the same year in which there is a dramatic increase in the gains reported by FPL. The record also shows that FPC and Gulf have experienced dramatic increases in gains on non-separated wholesale sales since 1996. Since 1996, FPC has received authority from FERC to charge market-based rates for out-of-state sales, and Gulf, through Southern, has received authority from FERC to charge market-based rates for in-state and out-of-state sales. Only TECO has experienced a recent decline in gains. TECO witness L. Brown explained that the decline in its gains from 1998 to 1999 was due to the lack of capacity resulting from the explosion at its Gannon Unit 6 last April. TECO received authority to charge market-based rates for in-state and out-of-state sales in April 1999.

OPC witness Dismukes testified that these changes to the wholesale market and other changes that have occurred in the electric industry since Order No. 12923 was issued in 1984 now provide the IOUs with the necessary incentives to make non-separated wholesale sales. According to witness Dismukes, "[n]o utility today can afford not to participate in the wholesale markets." Witness Dismukes testified that the IOUs face greater pressure today to keep their rates low due to the threat of customer loss resulting from retail competition and better options for self-generation. Witness Dismukes noted that making economy energy sales and crediting revenues from those sales to retail customers helps the IOUs to keep rates low. Further, witness Dismukes testified that today's more competitive wholesale market

provides the IOUs with greater opportunities and flexibility to make these sales. Therefore, OPC argues in its brief that the shareholder incentive established in Order No. 12923 is no longer necessary because there are other incentives driving the IOUs' participation in the wholesale market.

We agree that there are factors other than the 20 percent shareholder incentive that affect the IOUs' participation in the wholesale market. Clearly, as the IOUs' witnesses have readily admitted, they are not going to stop making economy energy sales if we eliminate the shareholder incentive approved in Order No. 12923. However, as all of the witnesses in this proceeding agreed, incentives may be used to prompt a positive response. The IOUs' witnesses testified that a shareholder incentive is an effective tool to drive management to focus on, and devote resources to, sustaining or increasing the level of their economy energy sales and the level of gains on those sales, in turn creating benefits for ratepayers. We agree. Thus, while there is no way to precisely measure the effect of a shareholder incentive on the IOUs' participation in the wholesale market, we find that a properly structured incentive will result in greater management efforts to increase economy energy sales, yielding gains on those sales to the benefit of ratepayers.

Further, as noted above and discussed in part II of this Order, FPC, FPL, and TECO are engaged in a broad range of non-separated wholesale energy sales to which an incentive is not currently applied, although the gains from these sales, which account for over 90 percent of these IOUs' total gains on non-separated sales, are credited to ratepayers to reduce the costs that they would otherwise have to bear. Thus, we find that a properly structured incentive may achieve even greater benefits for ratepayers by encouraging the types of sales from which ratepayers are currently receiving the greatest benefit. In conclusion, we find that the incentive program established in Order No. 12923 should not be eliminated, but should be modified to provide an appropriate incentive structure that reflects the changes in the wholesale market and the electric industry that have occurred since Order No. 12923 was issued and maximizes the potential benefits to ratepayers accordingly.

II. Structure for Shareholder Incentive

Five proposals were presented in this proceeding for the appropriate structure of an incentive on non-separated wholesale

power sales on a going-forward basis. These proposals are summarized as follows:

1. FPC witness Wieland proposed a 20 percent shareholder incentive on the gains from all non-separated sales, including firm sales. Witness Wieland proposes to include such sales made under existing Federal Energy Regulatory Commission (FERC) schedules and under new FERC schedules as they are approved.

2. FPL witness Dubin proposed a sliding scale approach to the shareholder incentive. The incentive would be applied to the gains on all non-firm, non-separated sales, including such sales made under newly approved FERC schedules. Under this proposal, FPL's shareholders would receive 20 percent of the first $20 million of gains, 40 percent of the next $20 million of gains, and 50 percent of the gains over $40 million. Witness Dubin stated that the specific thresholds for the sliding scale apply only to FPL and should be adjusted as appropriate for other IOUs.

3. Gulf witness Howell proposed no change to its current incentive treatment. As noted above, Gulf currently applies the 20 percent shareholder incentive to all non-firm, non-separated sales, including market-priced sales.

4. TECO witness L. Brown proposed a shareholder incentive on the gains from all non-firm, non-separated sales. Under TECO's proposal, the incentive varies based on whether the sale is an in-state or an out-of-state sale. TECO witness D. Brown proposed a 40 percent shareholder incentive for in-state sales, and a 20 percent incentive for out-of-state sales.

5. As stated above, OPC argued that an incentive is not necessary or appropriate. However, as an alternative, OPC witness Dismukes proposed an incentive only on gains from sales made over the Broker. Witness Dismukes suggested a five year moving average to determine a benchmark based on

> past energy sales. Under this proposal, an IOU would only receive an incentive if the benchmark is exceeded by 25 percent. The proposal would penalize an IOU if its sales are 75 percent of the benchmark or less.

As noted above, FIPUG argued that a shareholder incentive is not appropriate. Therefore, FIPUG did not offer a specific proposal for incentives.

A. Sales Eligible for Shareholder Incentive

As stated above, FPC, FPL, and TECO have applied the incentive approved in Order No. 12923 only to their sales under FERC Schedules C and X. As also noted above, these sales account for only 2.1%, 0.2%, and 6.8% of the total gains on non-separated wholesale sales in 1999 for FPC, FPL, and TECO, respectively. For example, the record shows that of the $59.2 million in gains earned by FPL on non-firm, non-separated wholesale energy sales, FPL received an incentive on sales that resulted in only $41,660 of those gains. FPL witness Stepenovitch testified that 75 to 80 percent of the gains on FPL's total non-separated wholesale energy sales for 1999 are attributed to market-based sales to which FPL does not currently apply a shareholder incentive. As the witnesses for these IOUs noted, the types of non-separated sales that did not qualify for an incentive have the same beneficial effect that Schedule C and X sales have: they reduce the costs that the selling utility's retail customers would otherwise have to bear. Accordingly, we agree that a properly structured shareholder incentive should encourage utility management, on a going-forward basis, to focus on sustaining and increasing the gains from this broader range of non-separated wholesale sales to provide cost reduction benefits to Florida's ratepayers.

FPC witness Wieland testified that both firm and non-firm, non-separated wholesale sales should be eligible for the shareholder incentive. He testified that in today's wholesale market it is difficult to differentiate between firm and non-firm wholesale sales because so many of these sales are made with various levels of "firmness." The record indicates that the recent grants of authority for the IOUs to engage in market-based transactions have provided the IOUs with greater flexibility in structuring wholesale transactions. This flexibility has led to more tailored, negotiated contract terms that provide various levels of commitment from the seller. Thus, we agree with witness

Wieland that in today's wholesale market, it will be very difficult, if not impossible, to prevent a shareholder incentive from being applied to sales with a certain degree of firmness.

FPC witness Wieland and FPL witness Stepenovitch both testified that the shareholder incentive should apply to both current and future FERC-approved schedules, as long as the sales made under these schedules are non-separated sales. Over time, utilities may petition the FERC for changes to existing FERC schedules and for new schedules as the market changes. Thus, we agree with FPC witness Wieland that structuring an incentive based only on current FERC schedules may lead to unnecessary difficulties in our administration of the incentive in the future.

All of the IOUs took the position that emergency sales should not be eligible for a shareholder incentive. As stated by FPC witness Wieland, emergency sales are "made upon the request of the buyer, not marketed by the seller." Therefore, emergency sales are less under a seller's control than other types of non-separated wholesale sales. Because emergency sales are primarily determined by the buyer's need for power, rather than the potential for cost savings, we agree that emergency sales should not be eligible for a shareholder incentive.

In summary, we find that to encourage the types of wholesale sales that are currently providing the greatest cost reduction benefit to Florida's retail ratepayers, a properly structured shareholder incentive should apply to all non-separated wholesale sales, firm and non-firm, excluding emergency sales, made under current and future FERC-approved schedules.

B. Level of Shareholder Incentive

As evidenced by the parties' various proposals, there are potentially an unending number of ways to devise an incentive. As FPC witness Wieland testified, there is no "magic number" for an appropriate incentive level. 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. We disagree with the IOUs' argument that an appropriate threshold cannot be determined because these sales are difficult to predict. The record shows that FPC, FPL, and TECO employ some type of sales standard in determining the compensation of marketing employees. Gulf has no marketing department, and Southern acts its agent for these sales. As TECO witness L. Brown testified, while it is difficult to establish these standards, it is nevertheless done.

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 for two reasons. First, as noted above, FERC Orders 888 and 889 have helped increase the volume of wholesale sales in the past three years. Second, Florida's two largest IOUs, FPL and FPC, received FERC approval for out-of-state market-based rates within the past three years. TECO also received approval to make both in-state and out-of-state market-priced sales. As OPC witness Dismukes testified, and as evidenced by the IOUs' level of non-separated wholesale transactions and gains, these factors have substantially impacted the potential gains for the IOUs. These two factors have caused a systemic change in the wholesale market in Florida.

As stated above, OPC witness Dismukes has proposed a five year moving average as part of its proposed reward/penalty methodology. We disagree that five years is an appropriate period. Including years prior to FERC Orders 888 and 889 and the IOUs' authority to engage in market-based transactions fails to recognize the market changes caused by these events and would set the incentive threshold too low. Thus, we believe this approach would reward the IOUs for normal effort, rather than the superior effort that should be required to receive an incentive.

Therefore, we find that a three year moving average of the gains on non-separated sales, firm and non-firm, excluding emergency sales, is an appropriate threshold for the shareholder incentive. All gains at or below this threshold shall be credited to the ratepayers. All gains above this threshold shall be split 80%/20% between ratepayers and shareholders, respectively. We find

that this incentive structure will allow ratepayers: (1) to continue to receive the substantial cost reduction benefits achieved through the IOUs' current level of non-separated sales; and (2) to benefit from a credit to the fuel clause of 80 percent of the gains on non-separated sales above the threshold. This incentive structure also minimizes the possibility that the IOUs could be rewarded for behavior that is already occurring. The IOUs are rewarded only for performing better than they performed, on average, over the previous three year period. To the extent an IOU surpasses the threshold, its threshold will increase for the next year. To the extent an IOU does not surpass the threshold, its shareholders will not receive as an incentive any portion of the gains that the IOU does achieve.

As noted above, both FPC witness Wieland and Gulf witness Howell proposed a 20 percent shareholder incentive as an appropriate incentive level. As witness Wieland conceded, the 20 percent figure is subjective in that there is no scientific basis used in selecting that percentage. However, we find that a 20 percent incentive is consistent with Order No. 12923, is reasonable, and should provide utilities with an adequate incentive.

We reject FIPUG and OPC's contention that any shareholder incentive structure should include a penalty for substandard performance, because imposing such a penalty would potentially counteract the incentive. We believe that the incentive approach described above is sufficient to encourage performance. As witness L. Brown testified and witness Dismukes conceded, a utility that does not make an adequate effort to make these sales is experiencing the opportunity cost of forgone profits. Further, we note that the shareholder incentive approved in Order No. 12923 did not include a penalty. Thus, including a penalty would represent a change in Commission policy which we believe has not been adequately justified.

We also reject FPL witness Dubin's sliding scale approach. We are not persuaded that IOU shareholders should receive a higher percentage incentive as gains increase. Witness Dubin admitted that the levels of FPL's sliding scale were subjective and not based on any analysis. Witness Dubin also testified that these levels should apply to FPL alone, and other levels should be developed for other IOUs. Thus, using a sliding scale approach places this Commission in the difficult position of developing the

gain levels for the scale for each IOU without any record evidence to support such a determination.

In addition, we reject TECO witness D. Brown's proposal to apply a higher incentive to in-state sales. The record evidence shows that approximately 95 percent of TECO's non-separated wholesale sales revenues are currently earned on in-state sales. Further, unlike FPL and FPC, TECO is authorized to make market-based sales in-state. Thus, providing a higher incentive on these sales would reward TECO for behavior that is already taking place. We are also concerned that providing a higher incentive on in-state sales could result in a perverse incentive for IOUs to make sales with the highest shareholder incentive, rather than the highest gain. Sales with the highest gain benefit the selling utility's ratepayers the most by resulting in the highest credit to ratepayers.

Finally, we reject the "deadband" approach proposed by OPC witness Dismukes. Witness Dismukes' approach calculates a benchmark based on a five-year moving average of sales made on the Broker. Under this approach, the IOU would credit 100 percent of the gains to ratepayers when the current year's sales fall between 75 and 125 percent of this benchmark. If a current year's sales exceed 125 percent of this benchmark, the IOU could retain for its shareholders up to 20 percent of those incremental gains. Conversely, if a current year's sales do not reach 75 percent of this benchmark, the IOU would incur a penalty up to 20 percent of the shortfall. Witness Dismukes proposed this deadband approach in part to reduce the possibility that IOUs would be rewarded for actions beyond their control. As discussed above, we believe that a 20 percent incentive on gains above a three year moving average would address these concerns. Further, we are concerned that the deadband could potentially reduce the impact of a shareholder incentive in encouraging these sales. Thus, we find that this deadband approach is inappropriate.

C. Conclusion

In conclusion, we approve the following as the appropriate structure for a shareholder incentive:

1. The incentive shall apply to the gains from all non-separated wholesale power sales, firm and non-firm, excluding emergency sales, made under current or future FERC-approved schedules.

2. A three year moving average of gains on all non-separated wholesale power sales, firm and non-firm, excluding emergency sales, shall be established each year as the threshold for application of the incentive. All gains below this threshold shall be credited to the ratepayers. All gains above this threshold shall be split 80%/20% between ratepayers and shareholders, respectively.

III. Notice of Proposed Agency Action - Calculation of Gains and Appropriate Regulatory Treatment

NOTICE is hereby given by the Florida Public Service Commission that the action discussed in this part only is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code.

The record of this proceeding indicates that the IOUs calculate total gains differently for similar types of non-separated wholesale power sales. Because the IOUs sell short-term wholesale energy based upon their willingness and ability to sell at or above incremental costs, we believe that the IOUs should measure the costs of these sales on an incremental basis. Accordingly, we find that each IOU shall measure the gain from its non-separated wholesale power sales by subtracting the sum of its incremental costs from the revenue received for each sale. Further, we find that the calculation of incremental costs for these sales shall include, but not be limited to: incremental fuel cost, incremental SO_2 emission allowance cost, incremental O&M cost, and separately-identified transmission or capacity charges.

In addition, we find that the following regulatory treatment for the revenues and expenses associated with each non-separated wholesale power sale is appropriate:

1. Each IOU shall credit its fuel and purchased power cost recovery clause for an amount equal to the incremental fuel cost of generating the energy for each such sale;

2. Except for FPC, each IOU shall credit its environmental cost recovery clause for an amount equal to the incremental SO_2 emission allowance cost of generating the energy for each such sale. FPC, because it does not have an environmental cost recovery clause, shall credit this

cost to its fuel and purchased power cost recovery clause;

3. Each IOU shall credit its operating revenues for an amount equal to the incremental operating and maintenance (O&M) cost of generating the energy for each such sale; and

4. In accordance with Order No. PSC-99-2512-FOF-EI, issued December 22, 1999, in Docket No. 990001-EI, each IOU shall credit its capacity cost recovery clause for an amount equal to any transmission revenues or separately identifiable capacity revenues.

If a person whose substantial interests are affected by our proposed action in this portion of the Order timely files a protest, the issue shall be addressed as part of our Fuel and Purchased Power Cost Recovery proceedings.

IV. Conclusions of Law

This Commisison is vested with jurisdiction over this matter through several provisions of Chapter 366, Florida Statutes, including Sections 366.04, 366.05, and 366.06, Florida Statutes.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the shareholder incentive mechanism approved in Order No. 12923, issued January 24, 1984, in Docket No. 830001-EU-B, is hereby modified as set forth in parts I and II of this Order. It is further

ORDERED that gains on non-separated wholesale power sales shall be calculated as set forth in part III of this Order. It is further

ORDERED that the revenues and expenses associated with non-separated wholesale power sales shall be treated for regulatory purposes as set forth in part III of this Order. It is further

ORDERED that the provisions of part III of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule 28-106.201, Florida Administrative Code, is received by the Director, Division of Records and Reporting, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that this Docket shall be closed after the time for filing an appeal of parts I and II has run or upon issuance of a Consummating Order on part III, whichever occurs later. If a person whose substantial interests are affected by the Commission's proposed action in part III timely files a protest, the issue shall be addressed as part of the Commission's Fuel and Purchased Power Cost Recovery proceedings, and this Docket shall be closed after the time for filing an appeal on parts I and II has run.

By ORDER of the Florida Public Service Commission this 26th day of September, 2000.

Blanca S. Bayó

BLANCA S. BAYÓ, Director
Division of Records and Reporting

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NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

As identified in the body of this order, our action in part III of this order is preliminary in nature. Any person whose substantial interests are affected by the action proposed in part III of this order may file a petition for a formal proceeding, in the form provided by Rule 28-106.201, Florida Administrative Code. This petition must be received by the Director, Division of Records and Reporting, at 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on October 17, 2000. If such a petition is filed, mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing. In the absence of such a petition, part III of this order shall become effective and final upon the issuance of a Consummating Order.

Any objection or protest filed in this docket before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.

Any party adversely affected by the Commission's final action in parts I and II of this order may request: (1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of Records and Reporting within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or (2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water or wastewater utility by filing a notice of appeal with the Director, Division of Records and Reporting and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

Appendix D

November 12, 2012

Testimony of James W. Daniel

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Florida Power & Light Company /	Docket No. 120015-EI Filed: November 2, 2012

DIRECT TESTIMONY

OF

JAMES W. DANIEL

ON BEHALF OF THE CITIZENS OF THE STATE OF FLORIDA

IN RESPONSE TO PUBLIC SERVICE COMMISSION

ORDER NO. PSC-12-0529-PCO-EI

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DIRECT TESTIMONY AND EXHIBITS OF

JAMES W. DANIEL

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DIRECT TESTIMONY OF JAMES W. DANIEL

On Behalf of the Office of Public Counsel

In Response to

Order No. PSC-12-0529-PCO-EI

I. PROFESSIONAL TRAINING AND EXPERIENCE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James W. Daniel. My business address is 919 Congress Avenue, Suite 800, Austin, Texas 78701.

Q. PLEASE OUTLINE YOUR FORMAL EDUCATION.

A. I received the degree of Bachelor of Science from the Georgia Institute of Technology in 1973 with a major in economics.

Q. WHAT IS YOUR PRESENT POSITION?

A. I am a Vice President of the firm GDS Associates, Inc. ("GDS") and Manager of GDS' office in Austin, Texas.

Q. WOULD YOU PLEASE DESCRIBE GDS?

A. GDS is an engineering and consulting firm with offices in Marietta, Georgia; Austin, Texas; Auburn, Alabama; Manchester, New Hampshire; Madison, Wisconsin; and Avon, Indiana. GDS has over 170 employees with backgrounds in engineering, accounting, management, economics, finance, and statistics. GDS provides rate and regulatory consulting services in the electric, natural gas, water,

and telephone utility industries. GDS also provides a variety of other services in the electric utility industry including power supply planning, generation support services, financial analysis, load forecasting, energy efficiency, renewable energy, and statistical services. Our clients are primarily publicly-owned utilities, municipalities, customers of privately-owned utilities, groups or associations of customers, and government agencies.

Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE.

A. From July 1974 through September 1979 and from August 1983 through February 1986, I was employed by Southern Engineering Company. During that time, I participated in the preparation of economic analyses regarding alternative power supply sources and generation and transmission feasibility studies for rural electric cooperatives. I participated in wholesale and retail rate and contract negotiations with investor-owned and publicly-owned utilities, prepared cost of service studies on investor-owned and publicly-owned utilities, and prepared and submitted testimony and exhibits in utility rate and other regulatory proceedings on behalf of publicly-owned utilities, industrial customers, associations and government agencies. From October 1979 through July 1983, I was employed as a public utility consultant by R. W. Beck and Associates. During that time, I participated in rate studies for publicly-owned electric, gas, water and wastewater utilities. My primary responsibility was the development of revenue requirements, cost of service, and rate design studies as well as the preparation and submission of testimony and exhibits in utility rate proceedings on behalf of publicly-owned utilities, industrial customers and other customer groups. Since

February 1986, I have held the position of Manager of GDS' office in Austin, Texas. In April 2000, I was elected as a Vice President of GDS. While at GDS, I have provided testimony in numerous regulatory proceedings involving electric, natural gas, and water utilities, I have participated in generic rulemaking proceedings, I have prepared retail rate studies on behalf of publicly-owned utilities, I have prepared utility valuation analyses, I have prepared economic feasibility studies, and I have procured and contracted for wholesale and retail energy supplies.

Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS AS AN EXPERT WITNESS?

A. Yes. I have testified many times before regulatory commissions. I have submitted testimony before the following state regulatory authorities: the State Corporation Commission of Kansas, the Georgia Public Service Commission, the Public Utility Commission of Texas, the Texas Commission on Environmental Quality, the Texas Railroad Commission, the South Dakota Public Utilities Commission, the New Mexico Public Service Commission, the Arizona Corporation Commission, the Louisiana Public Service Commission, the Arkansas Public Service Commission, the Oklahoma Corporation Commission, and the Illinois Commerce Commission. I have also testified before the Federal Energy Regulatory Commission ("FERC"), and two Condemnation Courts appointed by the Supreme Court of Nebraska, and I have submitted an expert opinion report before the United States Tax Court on utility issues. A list of

regulatory proceedings in which I have presented expert testimony is provided as Exhibit JWD-1.

II. INTRODUCTION

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Florida Office of Public Counsel ("OPC").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to review portions of the August 15, 2012 document captioned "Stipulation and Settlement Agreement" entered into by some of the parties to this proceeding ("August 15 document"). More specifically, I will address the reasonableness of allowing the Company to significantly expand its current incentive mechanism regarding gains on non-separated wholesale power sales in order to include in it a large number of additional transactions.

Q. ARE YOU SPONSORING ANY OTHER DOCUMENTS ALONG WITH YOUR TESTIMONY?

A. Yes. I am sponsoring Exhibits JWD-1 through JWD-2, which were prepared by me or under my supervision and direction.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. Based on my review of the August 15 document and testimony of FPL witness Sam A. Forrest filed on October 12, 2012 in support of it, I recommend that the Commission not approve paragraph 12 of the August 15 document, which would provide FPL with significant additional margin sharing opportunities. These proposed new margin sharing provisions were not included as part of FPL's original rate application and have been sprung on the parties, the Commission, and other utilities and potentially affected entities who are not parties to this case, through the August 15 document. The procedural schedule does not provide the parties, or other affected entities, the opportunity to conduct adequate discovery on the significant proposed changes to the incentive rate mechanism and does not provide them sufficient time to analyze fully the implications of these proposed changes. In addition, if the August 15 document is approved, the types of rate incentive mechanism changes proposed are likely to be sought by other utilities. Therefore, these proposed modifications are better considered in a generic rulemaking proceeding rather than in an expedited proceeding to consider a company-specific rate case stipulation. Perhaps more significantly, in my opinion the expanded incentive mechanism proposed by the signatories is unacceptably vague and open-ended; encompasses areas that prudent management should pursue without the necessity of incentives; and could result in unintended consequences, including a potential deterioration of reliable retail service and higher costs to ratepayers.

III. THE SIGNATORIES' PROPOSED INCENTIVE MECHANISM

Q. WOULD YOU BRIEFLY DESCRIBE THE INCENTIVE MECHANISM RELATED TO NON-SEPARATED WHOLESALE POWER SALES THAT IS CURRENTLY IN EFFECT?

A. Yes. FPL's current wholesale incentive mechanism, approved by Order No. PSC-00-1744-PAA-EI, issued September 26, 2000, allows the Company to retain 20% of the gains related to short-term power sales above a threshold amount. In Order No. PSC-00-1744-PAA-EI, the Commission directed utilities to credit 100% of gains associated with the amount below the threshold, and 80% above the threshold from these sales to ratepayers. Order at p. 2. The threshold amount is a function of a rolling three-year average of short-term power sales gains. Order at pp. 13-14. Short-term "savings" derived from the *purchase* of power are not part of the non-separated wholesale power sales incentive mechanism established by the Commission. Order at pp. 14-15. Since 2007, due in part to increases in fuel oil prices relative to natural gas prices, FPL's gains on economy *sales* have declined, and opportunities for economy *purchases* have increased. FPL has not shared in any gains since that time, per Exhibit SF-1 attached to the direct testimony of Sam. A. Forrest.

Q. PLEASE DESCRIBE THE SIGNATORIES' PROPOSED EXPANSION OF THE CURRENT WHOLESALE INCENTIVE MECHANISM.

A. The August 15 document would expand the current incentive mechanism to include several other types of transactions. In addition to the currently approved

short-term power sales gains that comprise FPL's existing gains on non-separated wholesale power sales, the August 15 document would include, but not be limited to, the following additional transactions:

1. natural gas storage transactions;
2. delivered city-gate natural gas sales;
3. production (upstream) area natural gas sales;
4. capacity releases of natural gas transportation;
5. selling idle, third party electric transmission capacity; and
6. outsourcing the asset management function to a third party in the form of an Asset Management Agreement ("AMA").

Q. HOW DOES FPL (AND OTHER SIGNATORIES) PROPOSE TO DIVIDE GAINS UNDER THE PROPOSED EXPANSION OF THE CURRENT INCENTIVE MECHANISM?

A. Pursuant to Paragraph 12(a)(iii), the proposed expansion of the incentive mechanism's proportional sharing arrangement is composed of the following elements:

1. Up to a "customer savings threshold" of $36 million, customers would receive 100% of the gain described in Paragraph 12(a)(i);
2. In addition, customers would receive 100% of the gain described in Paragraph 12(a)(i) for the first $10 million above the customer savings threshold;
3. FPL would retain 70% of incremental gains between $46 million and $75 million, and customers will receive 30%;

4. FPL would retain 60% and customers will receive 40% of incremental gains between $75 million and $100 million; and

5. FPL would retain 50% and customers will receive 50% of all incremental gains in excess of $100 million.

See, August 15 document at p. 14.

Q. PLEASE BRIEFLY DESCRIBE THE INCREMENTAL EXPENSES RATEPAYERS WOULD INCUR UNDER THE PROPOSED EXPANSION OF THE EXISTING INCENTIVE MECHANISM IN THE EVENT THAT THE AUGUST 15 DOCUMENT WERE TO BECOME EFFECTIVE.

A. Pursuant to Paragraph 12(b), FPL would be entitled to recover through its fuel clause incremental O&M expenses composed of the following elements:

(1) incremental personnel, software, and associated hardware costs incurred by FPL to manage the expanded short-term wholesale purchases and sales programs and the asset optimization measures; and

(2) variable power plant O&M expenses incurred by FPL to generate additional output in order to make wholesale sales, to the extent that the level of such sales exceeds 514,000 MWh, with such costs determined by multiplying the sales above that threshold times the monthly weighted average variable power plant O&M expenses per MWh reflected in the 2013 test year monthly reports.

Q. HOW WOULD GAINS ASSOCIATED WITH THE ELIGIBLE TRANSACTIONS BE INCLUDED IN THE EXPANDED INCENTIVE MECHANISM CONTEMPLATED BY THE AUGUST 15 DOCUMENT?

A. As contemplated under the August 15 document, each year FPL would file a final true-up schedule as part of its fuel cost recovery clause showing its gains in the prior calendar year on short-term wholesale sales, short-term wholesale purchases (including purchases that are reported on Schedule A-7), and all forms of asset optimization measures that it undertook in that year. Such measures would be subject to review by the Commission to determine eligibility for inclusion in the expanded incentive mechanism.

Q. WHAT ARE YOUR PRIMARY CONCERNS WITH THE EXPANSION OF THE WHOLESALE INCENTIVE MECHANISM PROPOSED WITHIN THE AUGUST 15 DOCUMENT?

A. The proposal would dramatically expand FPL's current, limited wholesale incentive mechanism in a number of presently unknowable and unquantifiable areas, with little justification as to the reasonableness of the requests. These concerns include the types of transactions eligible for the program, the derivations of the dollar amounts projected to be collected, the proportions expected to be retained by the Company, the extent to which the additional activities will affect the reliability and efficiency of electric service, and the expected level of incremental O&M expenses. My chief concern is that a proposal of this scope

could be approved based on the limited and imprecise information provided in this proceeding to date.

In order to conduct the type of comprehensive, thoughtful analysis that would be required to fully evaluate the consequences and effects on ratepayers if these additional margin sharing transactions are to be considered, FPL should be required to file meaningful support for this proposal. The parties then would need an appropriate amount of time to conduct discovery. The information provided to date is vague and lacks the relevant details required to develop a thorough understanding as to how the additional margin sharing transactions would be implemented, and whether ratepayers will see meaningful benefits. In addition, the proposal lacks necessary assurances that, if it were approved and implemented, the program would not undermine the FPL:s ability to fulfill its obligation to serve its customers reliably and efficiently at just and reasonable rates.

Q. HAS THE FPL DEMONSTRATED THAT THE INCLUSION OF THE PROPOSED ADDITIONAL MARGIN SHARING TRANSACTIONS WOULD BE BENEFICIAL TO CUSTOMERS?

A. No. FPL has offered an additional $10 million in margins to the current threshold, but has substantially increased the percentage of margins above the threshold that it would retain. As I will demonstrate later in my testimony, these higher margin retention percentages can result in less benefit to the customers in comparison to the current incentive mechanism.

When placed in the context of the Company's $378 million revenue requirement increase, the potential $10 million benefit to customers is a small percentage of the overall agreed-upon increase. Further, no information is provided as to the likelihood that these additional margin levels are reachable. In addition, no information has been provided to determine the extent of possible reliability issues associated with the growth of the new incentivized transactions, and whether the proposed proportional sharing amounts are required at all.

Q. ARE THERE OTHER CHANGES TO THE CURRENT INCENTIVE MECHANISM THAT CAUSE YOU CONCERN?

A. Yes. Under the current wholesale incentive mechanism, savings related to short-term power purchases are not part of the shared "margins" that FPL retains. This is reasonable, since short-term power purchase decisions should be part of a utility's normal practice under its fundamental economic dispatch process and objective, and the savings should be passed through to ratepayers. Under the proposed expansion of the incentive mechanism, FPL would be allowed to "keep" a significant portion of these savings above the threshold by charging ratepayers a higher fuel factor. In my 38 years of experience in electric rate regulation, I have never seen a case in which the utility had the audacity to claim that implementing the concept of economic dispatch should be a source of bonuses. Purchased power savings are a component of the concept of economic dispatches and should inure to the benefit of customers. They should be off limits to requests for incentives. In my view, this proposed sharing of the savings from short-term

power purchases is just a disguise for a revenue increase larger than the $378 million.

Q. DOES THE EXISTING REGULATORY FRAMEWORK REQUIRE ELECTRIC UTILITIES TO PROVIDE EFFICIENT SERVICE AT FAIR AND REASONABLE RATES?

A. Yes. Florida Statutes require the following:

> **366.03 General duties of public utility**
> Each public utility shall furnish to each person applying therefore reasonably sufficient, adequate, and ***efficient*** service upon terms as required by the commission. No public utility shall be required to furnish electricity or gas for resale except that a public utility may be required to furnish gas for containerized resale. All rates and charges made, demanded, or received by any public utility for any service rendered, or to be rendered by it, and each rule and regulation of such public utility, shall be ***fair and reasonable.***
> (Emphasis added)

Moreover, the Commission's rules impose an affirmative duty on electric utilities to minimize costs and to operate efficiently and reasonably in order to reduce costs for ratepayers. Specifically, Rule 26-6.0002, Application and Scope, provides that the Commission's rules are intended to define and promote good utility practices and procedures, and adequate and efficient service to the public at reasonable costs. In addition, Rule 25-6.140, Test Year Notification; Proposed Agency Action Notification, requires a statement describing the actions and measures implemented by the utility for the specific purpose of avoiding a rate increase.

Q. DOES FPL HAVE A DUTY TO PROVIDE EFFICIENT AND RELIABLE ELECTRIC SERVICE AT REASONABLE COSTS TO ITS CUSTOMERS?

A. Absolutely. In exchange for the opportunity to be the monopoly service provider in its service area, FPL has a duty to provide efficient and reliable electric service at reasonable costs to its customers. Therefore, absent sufficient justification in the form of benefits to customers, which is lacking in the August 15 document, as a matter of policy the Commission should not approve incentives that would result in unnecessary increases in profits for FPL and costs to its customers. An increase in profits should result from a utility taking on *extra* responsibility or risk that actually results in a corresponding increase in system efficiency and the reduction of rates or fuel costs for native-load customers. This is because native-load customers bear all the costs associated with implementing off-system sales.

Q. PLEASE EXPLAIN HOW NATIVE LOAD CUSTOMERS BEAR ALL EMBEDDED COSTS ASSOCIATED WITH SHORT-TERM OFF-SYSTEM SALES.

A. Native load customers pay for all resources electric utilities need to make off-system sales. Customers pay for the generating units, depreciation on the generating units, return on the utilities' investment in equipment, interconnections and ties with other utilities, natural gas storage facilities, dispatching equipment, non-fuel operations and maintenance expenses, and personnel and associated expenses incurred in making off-system sales. Because customers pay for the generating capacity and related facilities used in producing the electricity for short-term off-system sales, the margins created by those sales should be applied to reduce ratepayers' fuel costs, and the Commission has historically recognized this by allowing ratepayers to be credited for 100% of the margins below the

threshold and for 80% of the margins above the threshold through the current, limited wholesale incentive mechanism.

Q. DO SHAREHOLDERS BEAR ANY COSTS OR RISKS IN FPL'S OFF-SYSTEM SALES?

A. No. In fact, as the August 15 document proposes, any incremental costs associated with new transactions will be passed on to FPL's customers. Shareholders also bear no regulatory recovery risk as long as FPL demonstrates that a transaction resulted in margins above costs, so Commission disallowances are very remote. Therefore, there is no reason for allowing FPL to share in off-system sales margins over and above what the Commission has previously authorized. In fact, FPL should already be pursuing these potential additional margins pursuant to the Company's responsibility to provide efficient and low-cost electric service.

Q. COULD THE PROPOSED EXPANSION OF THE WHOLESALE SALES INCENTIVE MECHANISM CREATE INCENTIVES THAT WOULD BE DETRIMENTAL TO CUSTOMERS' INTERESTS?

A. Yes, I believe it could. Expanding the sharing of margins resulting from the additional proposed transactions would encourage FPL to engage in market transactions that could be more costly and could undermine reliability. The expanded sharing mechanism would create an incentive for FPL to deprive native load customers of less expensive power or capacity resources, which would be diverted to wholesale markets on which FPL could earn expanded profits through

the expanded incentive margins. The proposed expansion could also provide a disincentive for FPL to obtain the lowest cost fuel supplies for its power plants. These kinds of practices would actually turn the sharing of margins into a perverse incentive, and native load would be deprived of the lowest reasonable cost of energy.

Q. IF THE PROPOSED EXPANSION OF THE INCENTIVE MECHANISM HAD BEEN IN PLACE SINCE THE COMMISSION'S APPROVAL OF FPL'S CURRENT INCENTIVE MECHANISM, HOW MUCH OF THE CUSTOMER SAVINGS WOULD INSTEAD HAVE BEEN GIVEN TO FPL'S SHAREHOLDERS?

A. Based on my analysis, by including short-term purchased power in the determination of the shared margins, FPL's shareholders would have received more than $47.65 million of the savings that the customers have received under the current incentive mechanism since 2001. My Exhibit JWD-2 determines the total gains from short-term sales, and savings from short-term purchased power. It then compares the customers' and stockholders' shares of the benefits based on the current incentive mechanism to those based on the proposed expansion of the incentive mechanism. As Exhibit JWD-2 clearly demonstrates, had FPL's proposed expanded incentive mechanism been in effect during this period, fuel costs for ratepayers would have been $47.65 million more than the amount they actually incurred because that amount would have been given to FPL's stockholders. For this reason alone, the Commission should deny the proposal

because it increases costs to customers and provides FPL an unnecessary incentive to provide reliable electric service at reasonable rates.

Q. WOULD THE COMMISSION, THROUGH REGULATORY OVERSIGHT MECHANISMS SUCH AS RECONCILIATION REQUIREMENTS, POSITION ITSELF TO PROTECT CUSTOMERS FROM SUCH AN UNINTENDED CONSEQUENCE?

A. Unfortunately, no. In an "after-the-fact" fuel reconciliation proceeding, I believe it could be very difficult for interveners or Commission Staff to determine whether those utilized resources should have otherwise been dispatched for the benefit of native-load customers.

IV. LACK OF SUFFICIENT INFORMATION

Q. IN GENERAL, WHAT ARE YOUR CONCERNS WITH THE LACK OF INFORMATION SUPPORTING THE EXPANSION OF FPL'S EXISTING WHOLESALE INCENTIVE MECHANISM?

A. The new proposal in the August 15 document is a far-reaching and open-ended expansion of FPL's current, limited incentive mechanism. Currently, FPL is obligated to conduct off-system sales as long as those sales do not jeopardize service reliability, and the margins associated with the sales are used to offset reasonable and necessary fuel costs. However, pricing for off-system transactions which reflect market conditions are not the same as the embedded costs of providing electric service that are used in the setting of rates for native load

customers. See, FPL's Response to Staff's First Data Request No. 01-09(d). If the incentives to enter into off-system contracts are large enough, FPL could implement the transactions to the detriment of native load customers, undermining reliability. In addition, I have questions about specific parameters that comprise the expansion of FPL's current incentive mechanism.

Q. ARE YOU CONCERNED ABOUT THE UNDERLYING MARKET CONDITIONS ASSOCIATED WITH FPL'S PROPOSED INCENTIVE MECHANISM?

A. Yes. Uncertainty abounds with respect to the underlying market conditions that support FPL's proposed incentive mechanism. FPL has limited experience in contracting for the proposed asset optimization transactions, because the market conditions needed for its pursuits have not developed. Moreover, in its search to procure the necessary expertise, FPL has not been successful. Therefore, the potential to implement the proposed transactions remains untested for the most part. See, direct testimony of Sam. A. Forrest at page 15. FPL may at some point in the future be in an operational position to execute its asset optimization strategy; however, based on the information that it has provided to date, it would be premature to implement the program at this time without sufficiently considering the economic and reliability consequences for FPL's retail customers.

Q. HOW MANY OF THE PROPOSED INCENTIVE TRANSACTIONS DOES FPL CURRENTLY UTILIZE?

A. Currently, FPL contracts for the sale of idle electric transmission capacity, as well as for the sale of natural gas in production areas. See, FPL's Response to Staff's First Data Request No. 01-10. In addressing its historical lack of involvement in the proposed asset optimization transactions, FPL states that absent an approved program to be implemented via the expanded incentive mechanism, it would bear the risk for the outcome of each transaction, with no prospect for sharing in the gain. See, FPL's Response to Staff's Second Data Request No. 02-01. Therefore, considering FPL's dearth of expertise in the implementation of these transactions coupled with its inability to locate third-party expertise, Commission approval at this point would be untimely. Also, in responses to interrogatories, FPL has not addressed the specific components of the risks it faces, or explained how not entering into such transactions is consistent with its general duties as a public utility as required under Section 366.03, Florida Statutes.

Q. HAS FPL DEMONSTRATED THAT AN ADDITIONAL SHARING INCENTIVE ABOVE THE COMMISSION'S CURRENT 20% LEVEL IS WARRANTED?

A. No. FPL has not provided sufficient evidence for the Commission to conclude that sharing margins from its asset optimization transactions above the current level of 20% for its shareholders will actually increase the volume, or value, of off-system sales. The sharing mechanism may in fact encourage counter-productive behavior by FPL. Moreover, the Company has not provided sufficient evidence for the Commission to conclude that the proposed incentives are required for FPL to implement the wholesale market transactions. If wholesale

markets do not exist for FPL's proposed transactions, the costs related to incentivizing FPL to "create" them would trump any benefits. Given the potential scarcity of markets in place to support the execution of FPL's additional asset optimization transactions, combined with the lack of information FPL provided in supporting its proportional margin sharing agreement, another major concern is that the sharing arrangement does not appropriately recognize FPL's obligation to serve at just and reasonable rates.

Q. PLEASE STATE YOUR CONCERN WITH RELIABILITY ISSUES ASSOCIATED WITH THE PROPOSED EXPANSION.

A. I am concerned that the higher incentives in the proposed expansion would encourage FPL to pursue such margins at the expense of undermining electric service for its native load customers. To the extent the Commission believes that incentives are necessary to motivate conduct, the incentives should be designed to enhance or improve the service received by FPL's retail customers as FPL pursues the rewards of the incentive mechanism. In my opinion, the proposed expansion is not structured in this fashion. Instead, as structured, the proposal incentivizes FPL to enter into high dollar value transactions. As the dollar amounts of transactions rise, more of the resources whose costs FPL collects through native load rates would be dedicated to off-system purposes. This, in turn, would reduce FPL's reliability margin of error. While the Company has stated its commitment to reliability (See, direct testimony of Sam. A. Forrest at page16), to date it has not provided a sufficient amount of information related to the proposal to substantiate its claims. I believe that the Commission should be

cautious not to establish a system of incentives that it cannot police effectively to guard against abuse. As I mentioned earlier, I believe that any after-the-fact reconstruction whether FPL failed to give appropriate priority to the interests of the retail customers who are paying for the assets when it pursued opportunities for the high margins in its proposed expansion of the current incentive mechanism.

Q. PLEASE OUTLINE YOUR CONCERNS WITH THE INCREASED COSTS RETAIL CUSTOMERS WOULD BE REQUIRED TO PAY.

A. FPL estimates that for 2013, ratepayers would incur incremental O&M expenses of at least $500,000 regardless of the amount of gains, if any, resulting from the asset optimization program. FPL also estimates that as long as wholesale sales volume does not exceed a threshold of 514,000 MWh in 2013, the incremental variable generation-related O&M costs will be $0. See, FPL's Response to Staff's Second Data Request Nos. 02-02, and 02-03. The August 15 document requires that variable generation-related O&M costs be determined by multiplying the sales above the threshold times the monthly weighted average variable power plant O&M cost per MWh. As I state above, FPL, via the proportionate margin-sharing arrangement, is induced to pursue as many off-system transactions as possible. Yet, because costs are flowed through to customers in full, FPL has no inherent incentive to reduce costs in its implementation of higher-margin sharing transactions. That is because FPL can collect the costs associated with its proposed expansion of margin-sharing transactions dollar-for-dollar, and receive

the benefit of piecemeal ratemaking, while side-stepping any of the costs associated with the proposed expansion.

Q. WHAT IS PIECEMEAL RATEMAKING, AND WHY IS IT A CONCERN?

A. Piecemeal ratemaking occurs when a utility is allowed to adjust rates for changes in a specific cost category outside of a traditional base rate proceeding. Typically, it is only allowed in rare situations, e.g., for large, volatile expenses. The problem with piecemeal ratemaking is that it does not take into account the utility's total or overall costs. It is possible that other costs could be decreasing, thereby offsetting the specific cost increase the utility is proposing to recover. For example, if FPL is replacing old, deteriorated plant with new plant, then it is possible that maintenance expenses would be decreasing. Another example of this mismatch problem would be the costs eliminated or reduced by more efficient operations and maintenance procedures, while the Company collects new costs associated with its far-reaching proposed expansion of margin-sharing transactions. In effect, if the August 15 document is approved, the Commission will be issuing a blank check to FPL for the associated costs of its expanded asset optimization program. Moreover, as I stated above, an after-the-fact Commission review in which it could be very difficult for intervenors or Commission staff to determine whether the utilized resources should have otherwise been used for the benefit of native load customers does not ameliorate my concerns.

Q. PLEASE OUTLINE YOUR CONCERN ABOUT THE NATURE AND SCOPE OF THE ANNUAL REVIEW FOR THE PROPOSED EXPANSION OF THE INCENTIVE MECHANISM.

A. Very little information has been provided that addresses the nature and scope of the annual review of the proposed expansion, except that FPL would file a final true-up schedule FPL would file each year as part of its fuel cost recovery clause a final true-up schedule showing its gains in the prior calendar year on short-term wholesale sales, short-term wholesale purchases (including purchases that are reported on Schedule A-7), and all forms of asset optimization transactions that it undertook for the year. The August 15 document makes reference to FPL's final true-up having a description of each measure for which a gain is included in a total gains schedule, but nothing further. By this approach, the Commission would be placed in the undesirable position of reconstructing and verifying transactions with limited information on whether these were the most prudent use of ratepayer-funded resources.

Q. ARE YOU ALSO CONCERNED THAT IN FUTURE REVIEWS FPL WILL BE ALLOWED OPPORTUNITIES TO NOMINATE NEW TRANSACTIONS WITH LIMITED DOCUMENTATION SUPPORTING THE OPERATIONAL, EXPENSE, AND FINANCIAL TRADEOFFS TO RATEPAYERS?

A. Yes. As I stated above, reconstructing and verifying the complex dispatching and market operations associated with current wholesale transactions is resource intensive. Compounding the verification process with new and unique

transactions that would have to be dissected during a review with limited time parameters would further reduce the required oversight for such a mechanism.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH FPL'S PROPOSAL?

A. Yes. In addition to the concerns I discussed above, the types of rate incentive mechanism changes that FPL has proposed are likely to be sought by other utilities. In addition, the mechanism could affect the transactions that other utilities engage in and thus the sharing of gains by those utilities with their customers. Therefore, these proposed modifications are better considered in a generic rulemaking proceeding rather than in an expedited proceeding to consider a company-specific rate case stipulation. This approach would allow the Company and other utilities to provide one or more technical workshops so that the costs, risks, and other public interest concerns could be sufficiently addressed before moving forward with utilities implementing any approved transactions statewide.

V. SUMMARY AND CONCLUSIONS

Q. WOULD YOU PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATION?

A. Yes. Based on my review of the August 15 document and testimony filed in support of it, I believe that FPL has not demonstrated that paragraph 12 of the August 15 document, which would provide FPL with significant additional margin-sharing opportunities, is fair and reasonable, or would produce benefits to

customers. To the contrary, in my opinion the proposed expansion and reformulation of the current incentive mechanism is vague, unsupported, unreasonably one-sided in favor of FPL, and would create counterproductive incentives and unintended consequences that would be detrimental to customers and difficult for the Commission to guard against. In addition, if the August 15 document is approved, the types of rate incentive mechanism changes proposed are likely to be sought by other utilities. Therefore, these proposed modifications are better considered in a generic rulemaking proceeding rather than in an expedited proceeding to consider a company-specific rate case stipulation.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and foregoing **Direct Testimony of James W. Daniel** has been furnished by electronic mail on this 2nd day of November, 2012, to the following:

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Florida Public Service Commission
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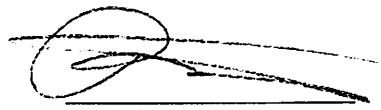

Patricia A. Christensen
Associate Public Counsel

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
1/1/1976	Federal Power Commission	ER76-530	Arizona Public Service Company
2/76	South Dakota Public Utility Commission	F-3055	Northwestern Public Service Company
5/79	Federal Energy Regulatory Commission	ER78-379,ER78-380 ER78-381,ER78-382 ER78-383	Indiana & Michigan Electric Company
11/80	New Mexico Public Service Commission	1627	Kit Carson Electric Cooperative (Direct Testimony)
6/81	Arizona Corporation Commission	9962-E-1032	Citizens Utilities Company
9/81	Federal Energy Regulatory Commission	ER81-179	Arizona Public Service Commission (Direct Testimony)
3/84	Texas Public Utility Commission	5640	Texas Utilities Electric Company
4/2/1984	Public Utility Commission of Texas	5560	Gulf States Utility Company (Direct Testimony)
7/3/84	Texas Public Utility Commission	5640	Texas Utilities Electric Company (Direct Testimony)
11/15/1984	Texas Public Utility Commission	5709	Texas Utilities Electric Company (Direct Testimony)
1/85	Federal Energy Regulatory Commission	ER84-568-000	Gulf States Utilities Company (Direct Testimony)
11/20/1985	Federal Energy Regulatory Commission	ER85-538-001	Gulf States Utilities Company (Direct Testimony)
1/7/86	Louisiana Public Service Commission	U-16510	Central Louisiana Electric Company (Direct Testimony)
3/10/86	Texas Public Utility Commission	6677	Texas Utilities Electric Company
3/14/86	Federal Energy Regulatory Commission	ER85-538-001	Gulf States Utilities Company (Rebuttal and Surrebuttal Testimony)
6/20/88	Texas Public Utility Commission	8032	Lower Colorado River Authority (Direct Testimony)
7/15/88	Texas Public Utility Commission	8032	Lower Colorado River Authority (Supplemental Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
3/7/90	Texas Public Utility Commission	9165	El Paso Electric Company (Direct Testimony)
4/12/90	Texas Public Utility Commission	9300	Texas Utilities Electric Company (Direct Testimony - Revenue Requirements Phase)
5/1/1990	Texas Public Utility Commission	9300	Texas Utilities Electric Company (Direct Testimony - Phase II - Rate Design)
7/6/90	Texas Public Utility Commission	9300	Texas Utilities Electric Company (Supplemental Testimony - Revenue Requirements)
7/10/90	Texas Public Utility Commission	9427	Lower Colorado River Authority (Direct Testimony - Rate Design)
7/30/90	Texas Public Utility Commission	9427	Lower Colorado River Authority (Rebuttal Testimony - Rate Design)
8/23/90	Texas Public Utility Commission	9561	Central Power & Light Company (Direct Testimony - Rate Design)
1/11/91	Texas Public Utility Commission	9427	Lower Colorado River Authority (Rebuttal Testimony)
9/24/91	Texas Public Utility Commission	10404	Guadalupe Valley Electric Cooperative (Direct Testimony)
12/91	Rate Area 2&3 Nebraska Municipalities	N/A	Peoples Natural Gas Company
7/31/92	Texas Public Utility Commission	11266	Guadalupe-Blanco River Authority (Direct Testimony)
8/7/92	State Corporation Commission of Kansas	180,416-U	Peoples Natural Gas Company (Direct Testimony)
9/8/92	Texas Public Utility Commission	11266	Guadalupe-Blanco River Authority (Direct Testimony)
9/92	Texas Public Utility Commission	10894	Gulf States Utilities Company (Direct Testimony)
5/93	Texas Public Utility Commission	11735	Texas Utilities Electric Company (Rebuttal Testimony)
6/93	Texas Public Utility Commission	11892	Generic Proceeding Regarding Purchased Power (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
09/08/93	State Corporation Commission of Kansas	186,363-U	KN Energy (Direct Testimony)
09/94	State Corporation Commission of Kansas	190,362-U	Kansas Natural Pipeline and Kansas Natural Partnership (Direct Testimony)
10/17/94	Texas Public Utility Commission	12820	Central Power and Light Company (Direct Testimony)
11/15/1994	City of Houston	NA	Houston Lighting and Power Company (Direct Testimony)
11/15/1994	Texas Public Utility Commission	12065	Houston Lighting and Power Company (Direct Testimony - Revenue Requirements Phase)
12/12/1994	Texas Public Utility Commission	12820	Central Power & Light Company (Supplemental Testimony)
1/10/1995	Texas Public Utility Commission	12065	Houston Lighting & Power Company (Direct Testimony - Rate Design Phase)
5/23/95	Federal Energy Regulatory Commission	TX94-4-000	Texas Utilities Electric Company and Southwestern Electric Service (Affidavit)
8/7/95	Texas Public Utility Commission	13369	West Texas Utilities Company (Rebuttal Testimony - Rate Design Phase)
10/31/95	Texas Public Utility Commission	14435	Southwestern Electric Power Company (Direct Testimony)
11/95	Rate Area 3 Nebraska Municipalities	N/A	Peoples Natural Gas Company (Municipal Report)
02/07/96	Federal Energy Regulatory Commission	TX96-2-000	City of College Station, Texas (Affidavit)
5/15/96	Texas Public Utility Commission	14965	Central Power & Light Company (Direct Testimony)
5/29/1996	Texas Public Utility Commission	14965	Central Power & Light Company (Rebuttal Testimony)
07/19/96	Texas Public Utility Commission	15766	City of Bryan, Texas (Direct Testimony)
8/29/1996	Texas Public Utility Commission	15296	City of Bryan, Texas (Direct Testimony)
08/07/96	State of Illinois Commerce Commission	96-0245 & 96-0248	Commonwealth Edison Company (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
09/06/96	Texas Public Utility Commission	15643	Central Power & Light Company and West Texas Utilities Company (Direct Testimony)
9/17/1996	Texas Public Utility Commission	15296	City of Bryan, Texas (Rebuttal Testimony)
09/18/96	Texas Public Utility Commission	15638	Texas Utilities Electric Company (Direct Testimony)
10/22/96	Texas Natural Resource Conservation Commission	96-0652-UCR	Longbranch Associates, L.P. (Direct Testimony)
08/05/97	Arkansas Public Service Commission	97-019-U	Arkansas Western Gas Company (Direct Testimony)
08/06/97	Texas Public Utility Commission	16705	Entergy Texas (Direct Testimony)
08/25/97	Texas Public Utility Commission	16705	Entergy Texas (Rebuttal Testimony - Rate Design Phase)
09/23/97	Arkansas Public Service Commission	97-019-U	Arkansas Western Gas Company (Surrebuttal Testimony)
09/30/97	Texas Public Utility Commission	16705	Entergy Texas (Direct Testimony - Competitive Issues Phase)
12/97	United States Tax Court	7685-96 and 4979-97	Lykes Energy, Inc. (Report)
12/97	Condemnation Court Appointed by the Supreme Court of Nebraska	13880	Peoples Natural Gas
12/1/1997	Condemnation Court Appointed by the Supreme Court of Nebraska	NA	Peoples Natural Gas Company (Report to City of Wahoo, Nebraska)
8/1/1998	Condemnation Court Appointed by the Supreme Court of Nebraska	101	Peoples Natural Gas (Report to City of Scribner, Nebraska)
10/98	Federal Energy Regulatory Commission	EL-99-6-000	Entergy Gulf States, Inc. (Affidavit)
10/19/1998	Federal Energy Regulatory Commission	TX98-	Gulf States Utilities Company (Affidavit)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
12/31/1998	Texas Public Utility Commission	20292	Sharyland Utilities, L.P. (Direct Testimony)
3/11/1999	Texas Public Utility Commission	20292	Sharyland Utilities, L.P. (Supplemental Testimony)
4/30/1999	Texas Public Utility Commission	20292	Sharyland Utilities, L.P. (Rebuttal Testimony)
7/16/1999	Texas Public Utility Commission	19265	Central and South West Corporation and American Electric Power Company, Inc. (Direct Testimony)
11/1/1999	Texas Public Utility Commission	21591	Sharyland Utilities, L.P. (Direct Testimony)
11/24/1999	Texas Public Utility Commission	21528	Central Power and Light Company (Direct Testimony)
1/27/2000	Texas Railroad Commission	8976	Texas Utilities Company Lone Star Pipeline (Direct Testimony)
3/31/2000	Texas Public Utility Commission	22348	Sharyland Utilities, L.P. (Direct Testimony)
08/2000	Texas Public Utility Commission	20624	Reliant Energy HL&P (Direct Testimony)
10/16/2000	Texas Public Utility Commission	22344	Generic Issues Associated with Unbundled Cost of Service Rate (Direct Testimony)
10/23/2000	Texas Public Utility Commission	21956	Reliant Energy, Inc. (Direct Testimony)
11/14/2000	Texas Public Utility Commission	22350	TXU Electric Company (Direct Testimony)
11/17/2000	Texas Public Utility Commission	22352	Central Power and Light Company (Direct Testimony)
12/12/2000	Texas Public Utility Commission	22355	Reliant Energy HL&P (Direct - Final Phase) (Direct Testimony)
12/21/2000	Texas Public Utility Commission	22355	Reliant Energy HL&P (Direct Testimony - Rate Case Expense Phase)
12/29/2000	Texas Public Utility Commission	22355	Reliant Energy HL&P (Supplemental & Rebuttal Testimonies)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
7/5/2001	Texas Public Utility Commission	23950	Reliant Energy (Direct Testimony)
9/6/2001	Texas Public Utility Commission	24239	Mutual Energy CPL, LP (Direct Testimony)
4/22/2002	State Corporation Commission of Kansas	02-WSRE-301-RTS	Western Resources, Inc. and Kansas Gas and Electric Company (Direct Testimony)
6/19/2002	Federal Energy Regulatory Commission	TX96-2-000	City of College Station, Texas (Direct Testimony)
8/5/2002	Corporation Commission of the State of Oklahoma	200100455	Oklahoma Corporation Commission (Direct Testimony)
12/31/2002	Texas Public Utility Commission	26195	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
4/24/2003	Texas Public Utility Commission	25089	Market Protocols for the Portions of Texas Within the Southeastern Reliability Council (Rebuttal Testimony)
6/9/2003	Texas Public Utility Commission	25089	Market Protocols for the Portions of Texas Within the Southeastern Reliability Council (Supplemental Direct Testimony)
7/11/2003	State Corporation Commission of Kansas	03-KGSG-602-RTS	Kansas Gas Service, a Division of ONEOK, Inc. (Direct Testimony)
8/11/2003	Texas Public Utility Commission	25089	Market Protocols for the Portions of Texas Within the Southeastern Reliability Council (Second Supplemental Direct Testimony)
8/18/2003	State Corporation Commission of Kansas	03-KGSG-602-RTS	Kansas Gas Service, a Division of ONEOK, Inc. (Supplemental Testimony)
10/29/2003	Federal Energy Regulatory Commission	ER04-35-000	Entergy Services, Inc. (Affidavit)
11/5/2003	Texas Public Utility Commission	26195	CenterPoint Energy Houston Electric, LLC (Supplemental Direct Testimony)
2/9/2004	Texas Public Utility Commission	28840	AEP Texas Central Company (Direct Testimony)
6/1/2004	Texas Public Utility Commission	29526	CenterPoint Energy Houston Electric, LLC, Reliant Energy Retail Services, LLC, and Texas Genco, LP (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
8/30/2004	Texas Public Utility Commission	28813	Cap Rock Energy Corporation (Direct Testimony)
1/7/2005	Texas Public Utility Commission	30485	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
3/16/2005	Texas Public Utility Commission	30706	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
6/9/2005	Texas Public Utility Commission	29801	Southwestern Public Service Company (Direct Testimony)
9/2/2005	Texas Public Utility Commission	31056	AEP Texas Central Company and CPL Retail Energy, LP (Direct Testimony)
9/9/2005	State Corporation Commission of Kansas	05-WSEE-981-RTS	Westar Energy, Inc. and Kansas Gas and Electric Company (Direct Testimony)
9/29/2005	Georgia Public Service Commission	20298-U	Atmos Energy Corporation (Direct Testimony)
4/24/2006	Texas Public Utility Commission	32475	AEP Texas Central Company (Cross Answering Testimony)
8/11/2006	Texas Public Utility Commission	32093	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
8/23/2006	Texas Public Utility Commission	32795	Reallocation of Stranded Costs Pursuant to PURA §139.253(f) (Direct Testimony)
8/24/2006	Texas Public Utility Commission	32758	AEP Texas Central Company (Direct Testimony)
12/22/2006	Texas Public Utility Commission	32766	Southwestern Public Service Company (Direct Testimony)
3/13/2007	Texas Public Utility Commission	33309	AEP Texas Central Company (Direct Testimony)
3/19/2007	State Corporation Commission of Kansas	07-AQLG-431-RTS	Aquila Networks-KGO (Direct Testimony)
4/27/2007	Texas Public Utility Commission	33687	Entergy Gulf States, Inc. (Direct Testimony)
7/11/2007	Texas Public Utility Commission	33823	CenterPoint Energy Houston Electric, LLC (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
7/13/2007	Texas Public Utility Commission	33687	East Texas Cooperatives (Supplemental Testimony)
1/11/2008	Texas Public Utility Commission	35219	Guadalupe Valley Electric Cooperative, Inc (Direct Testimony)
1/29/2008	Texas Public Utility Commission	35287	Sharyland Utilities, L.P. (Direct Testimony)
7/1/2008	Georgia Public Service Commission	27163	Atmos Energy Corporation (Direct Testimony)
9/16/2008	Texas Public Utility Commission	34442	JD Wind (Direct Testimony)
9/29/2008	State Corporation Commission of the State of Kansas	08-WSEE-1041-RTS	Westar Energy, Inc. and Kansas Gas and Electric Company (Direct Testimony)
10/13/2008	Texas Public Utility Commission	35763	Southwestern Public Services Company (Direct Testimony)
11/26/2008	Texas Public Utility Commission	35717	Oncor Electric Delivery Company (Direct Testimony)
6/26/2009	State Corporation Commission of the State of Kansas	09-WSEE-641-GIE	Westar Energy, Inc. and Kansas Gas and Electric Company (Direct Testimony)
6/29/2009	Texas Public Utility Commission	36918	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
9/30/2009	State Corporation Commission of the State of Kansas	09-WSEE-925-RTS	Westar Energy, Inc. and Kansas Gas and Electric Company (Direct Testimony)
7/10/2010	Pennsylvania Public Utility Commission	R-2010-2161575, et. al.	PECO Energy Company (Direct Testimony)
9/3/2010	Texas Public Utility Commission	38324	Oncor Electric Delivery Company, LLC (Direct Testimony)
9/10/2010	Texas Public Utility Commission	38339	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
9/24/2010	Texas Public Utility Commission	38339	CenterPoint Energy Houston Electric, LLC (Cross-Rebuttal Testimony)
9/27/2010	Texas Public Utility Commission	38324	Oncor Electric Delivery Company, LLC (Cross-Rebuttal Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
11/5/2010	Texas Public Utility Commission	38577	Modification of CREZ Transmission Plan (Direct Testimony)
2/4/2011	Texas Railroad Commission	GUD 10038	CenterPoint Energy Texas Gas (Direct Testimony)
3/1/2011	Texas Public Utility Commission	39070	Sharyland Utilities, L.P. (Direct Testimony)
10/19/2011	Texas Public Utility Commission	39856	Guadelupe Valley Electric Cooperative (Direct Testimony)
5/1/2012	Texas Public Utility Commission	40364	Sharyland Utitilies, L.P. (Direct Testimony)
5/15/2012	Delaware Public Service Commisison	11-528	Delmarva Power & Light Company (Direct Testimony)

Florida Public Service Commission
Docket No. 120015-E1

Increase in FPL Profits
If Proposed Incentive Mechanism
Had Been In Effect Since 2001

Line No.	Year	Proposed Incentive Mechanism: Total Claimed Benefits*	Proposed Claimed Benefits less Threshold of $46,000,000	Customer's Share of Claimed Benefits				FPL's Share of Claimed Benefits			
				Current Incentive Mechanism		Proposed Incentive Mechanism		Current Incentive Mechanism		Proposed Incentive Mechanism	
				Amount	% of Total	Amount	% of Total	Amount	% of Total	Amount	% of Total
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	2003	$47,939,149	$1,939,149	$47,939,149	100.00%	$46,581,745	97.17%	$0	0.00%	$1,357,404	2.83%
2	2005	$49,612,011	$2,481,777	$48,481,777	97.72%	$46,744,533	94.22%	$1,130,234	2.28%	$1,737,244	3.50%
3	2009	$50,452,089	$4,452,089	$50,452,089	100.00%	$47,335,627	93.82%	$0	0.00%	$3,116,462	6.18%
4	2010	$82,738,350	$36,738,350	$82,738,350	100.00%	$57,795,340	69.85%	$0	0.00%	$24,943,010	30.15%
5	2011	$69,563,423	$23,563,423	$69,563,423	100.00%	$53,069,027	76.29%	$0	0.00%	$16,494,396	23.71%
6	Total	$300,305,022	$69,174,788	$299,174,788	99.62%	$251,526,271	83.76%	$1,130,234	0.38%	$47,648,517	15.87%

* From FPL's Exhibit SF-2, page 1 of 1