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July 14, 2014

Ms. Carlotta Stauffer, Director
Commission Clerk and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida, 32399-0850

Via Web-Based Electronic Filing

Re: Docket No. 140110-EI, Petition for Determination of Need for Citrus County Combined Cycle Plant, and
Docket No. 140110-EI, Petition for Determination of Cost-Effective Generation Alternative to Meet Need Prior to 2018 for Duke Energy Florida, Inc.

Dear Ms. Stauffer:

On July 14, 2014, NRG Florida LP filed the redacted testimony of Jeffry Pollock, and filed the confidential portion of Mr. Pollock's testimony under separate confidential cover. After Mr. Pollock's testimony was filed, Duke Energy Florida confirmed that the information referenced in Mr. Pollock's testimony was not confidential, although it was provided in a confidential filing. Accordingly, NRG hereby withdraws the redacted testimony and its confidential filing, and hereby substitutes Mr. Pollock's revised testimony, without redaction.

Thank you for your assistance with this filing. Please do not hesitate to contact me if you have any questions or concerns.

Sincerely,

/S/ Marsha E. Rule

Marsha E. Rule

Cc: All parties of record

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018, by Duke Energy Florida, Inc.	**DOCKET NO. 140111-EI**
In re: Petition for Determination of Need for Citrus County Combined Cycle Power Plant, by Duke Energy Florida, Inc.	**DOCKET No. 140110-EI** **Filed: July 14, 2014**

DIRECT TESTIMONY AND EXHIBITS OF JEFFRY POLLOCK

ON BEHALF OF NRG FLORIDA, LP

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LIST OF ACRONYMS

Term	Definition
CR3	Crystal River Unit No. 3
CR South	Crystal River Units 1 and 2
CT	Combustion Turbine
DEF	Duke Energy Florida , Inc.
EPC	Engineering, Procurement and Construction
IOU	Investor-Owned Utility
kW	Kilowatt
kWh	Kilowatt Hour
MW	Megawatt
NPVRR	Net Present Value Revenue Requirement
NRG	NRG Florida LP
PEF	Progress Energy Florida
PPA	Purchased Power Agreements
TECO	Tampa Electric Company

DIRECT TESTIMONY OF JEFFRY POLLOCK

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock; 12647 Olive Blvd., Suite 585, St. Louis, MO 63141.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J.Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University. I have also completed a Utility Finance and Accounting course.

Upon graduation in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to November 2004, I was a managing principal at Brubaker & Associates (BAI).

During my tenure at both DBA and BAI, I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, and conducting site evaluation. I have also advised clients on electric restructuring issues including procuring and managing electricity in both competitive and regulated markets, developed and issued requests for proposals (RFPs), evaluated RFP responses, supported contract negotiations, and developed and presented seminars on electricity issues.

I have worked on various projects in over 20 states and several Canadian provinces, and have testified before the Federal Energy Regulatory Commission and the state regulatory commissions of Alabama, Arizona, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, Ohio, Pennsylvania, Texas, Virginia, Washington, and Wyoming. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court. A partial list of my appearances is provided in **Exhibit___(JP-1).**

Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

A J.Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J.Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J.Pollock is a registered Class I aggregator in the State of Texas.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of NRG Florida LP (NRG). NRG participated in the process that led to Duke Energy Florida, Inc.'s (DEF) decision to pursue its own self-build projects (*i.e.*, Suwannee Simple Cycle and Hines Chiller Uprate) to meet its purported capacity needs prior to 2018.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A My testimony addresses Issues 9, 10, 13, 14, and 15 identified in Order No.

PSC-14-0341-PCO-EI issued in the combined proceedings.[1] Specifically, I will demonstrate how Acquisition 1 is a better choice to meet DEF's capacity needs than DEF's proposed self-build projects.

Q ARE OTHER WITNESSES TESTIFYING ON NRG'S BEHALF IN THIS PROCEEDING?

A Yes. NRG is sponsoring the testimony of Mr. Jim Dauer and Mr. John Morris. Mr. Dauer's testimony addresses the firm transportation costs associated with Acquisition 1 and how DEF's assumptions understate the benefits and overstate the cost of Acquisition 1 relative to its self-build projects. Mr. Morris's testimony will address DEF's market power analysis. Specifically, he will demonstrate that contrary to DEF's assumptions, Acquisition 1 does not fail FERC's Competitive Analysis Screen if the acquisition is properly structured.

Q ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A Yes. I am sponsoring **Exhibit___(JP-1)** through **Exhibit___(JP-6).** These exhibits were prepared by me or under my supervision and direction.

Summary

Q PLEASE SUMMARIZE YOUR TESTIMONY.

A My testimony discusses the reasons why Acquisition 1 is a better and more cost-effective choice for meeting DEF's purported capacity needs prior to 2018 than DEF's proposed Suwannee Simple Cycle and Hines Chiller Uprate projects. The

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[1] Docket Nos. 140110 and 140111, *Third Order Establishing Procedure And Order Granting Motion For Alternate Testimony Filing Dates*, Appendix A.

reasons are:

- Acquisition 1 is less costly and more cost-effective than DEF's proposed self-build projects;
- Acquisition 1's 471 MW of generating capacity is sufficient to meet DEF's capacity needs prior to 2018;
- Acquisition 1 is less risky for DEF's customers; and
- Acquisition 1 restrains the steadily increasing upward pressure on DEF's already high electricity rates as compared to the proposed self-build projects.

Acquisition 1

Q WHAT IS ACQUISITION 1?

A Acquisition 1 is NRG's Osceola generating station. It consists of three simple cycle combustion turbines (CTs), each having a summer rated capacity of 157 Megawatts (MW). The units are GE Frame 7FA gas turbines. According to GE:

> The reliability of the 7FA gas turbine has been consistently 98 percent or better. This high reliability provides customers more days of operation per year while minimizing the overall life cycle cost of the gas turbine.[2]

Osceola station is located in DEF's service area, in Osceola County, Florida. It is interconnected to DEF and operates within DEF's balancing authority. The three units have been in commercial operation since 2001 and 2002. They have demonstrated the ability to efficiently provide 465 MW (summer) of reliable capacity. The primary fuel source is natural gas. However, the units are also capable of operating on distillate fuel oil.

Q HAS THE OSCEOLA GENERATING STATION SUPPLIED CAPACITY TO UTILITIES IN FLORIDA?

A Yes. According to SNL Financial, the Osceola station supplied capacity to

[2] http://site.ge-energy.com/prod_serv/products/gas_turbines_cc/en/f_class/ms7001fa.htm.

Seminole Electric Cooperative (Seminole) under a five-year contract that ended in May 2014. I understand that the Station previously sold power to DEF's predecessor, Progress Energy Florida (PEF) from 2006 to 2009 and to Seminole for the five years after achieving commercial operation. This experience demonstrates how the Osceola station has provided a reliable source of power in Florida.

<u>Cost-Effectiveness</u>

Q IS ACQUISITION 1 COST-EFFECTIVE?

A Yes. DEF admits that Acquisition 1 is a lower cost and more cost-effective option than the proposed self-build projects. This is demonstrated in Exhibit___(BMHB-8), which provides a summary of DEF's cost-effectiveness analysis. Specifically, this exhibit quantifies the 30-year cumulative net present value revenue requirement (NPVRR) differential between each "package" of alternative resources and a package consisting of the proposed self-build projects. Based on DEF's analysis, Acquisition 1 is $49 million less costly than DEF's proposed self-build projects. Acquisition 1 is also the only non self-build alternative that is more cost-effective, according to DEF's analysis.

Q DOES NRG AGREE WITH THE ASSUMPTIONS USED BY DEF IN EVALUATING ALTERNATIVE RESOURCES, SUCH AS ACQUISITION 1?

A No. As discussed later, there are three errors in DEF's evaluation. The three errors are:

- DEF over-stated the fixed costs associated with Acquisition 1 by about $60 million because it ignored the existing fuel supply arrangements and assumed that additional firm gas transportation capacity would be needed.[3]

- It misapplied FERC's Competitive Analysis (market power) Screen in eliminating Acquisition 1 as a viable alternative.
- It included equity costs by imputing additional debt to the projected cost of purchased power agreements (PPAs).

Further, DEF erred because it did not include any incremental fuel delivery or service costs in its analysis of the self-build projects.[4] Collectively, these errors bias the evaluation in favor of DEF's self-build projects. However, when the correct assumptions are used, Acquisition 1 is not only more cost effective, it is a lower cost, low risk, viable alternative to DEF's self-build projects.

Q DID DEF CONSIDER ANY OF THE ADVANTAGES OF ACQUISITION 1 RELATIVE TO NEW SELF-BUILD CAPACITY IN ITS EVALUATION?

A DEF apparently overlooked some of the advantages of Acquisition 1. As previously stated, Acquisition 1 is an existing facility. It has been operational since 2001. Further, it is a more modern facility than the 261 MW of capacity that DEF is planning to retire over the next three years, including the three existing steam units at the Suwannee site. Thus, Acquisition 1 can provide the peaking capacity that DEF alleges it needs more efficiently than DEF's existing CTs and would avoid the significant additional capital costs associated with DEF's proposed new self-build generation capacity.

Q IS THERE ANY OTHER ADVANTAGE OF ACQUISITION 1?

A Yes. The purchase price of Acquisition 1 would be fixed; that is, the amount paid

[3] DEF's Response to NRG Interrogatory No. 76.

[4] DEF's Response to Calpine's Production of Documents Request No. 6 and DEF's Response to NRG's Production of Documents Request No. 7, which contain competitively sensitive confidential information.

by DEF would be negotiated and this amount would be reflected in DEF's rate base. By contrast, DEF will seek recovery of the entire cost of constructing the Suwannee and Hines projects. Thus, even though DEF is now estimating a total construction cost of $197 million for the Suwannee CTs and $160 million for the Hines Chiller Uprate, because these projects are not subject to the determination of need process, DEF may seek recovery of any additional costs actually incurred if it can demonstrate that they were prudently incurred. Thus, Acquisition 1 avoids the risk to DEF and its customers associated with cost over-runs.

Q HOW DID DEF OVERSTATE THE GAS TRANSPORTATION COSTS ASSOCIATED WITH ACQUISITION 1?

A DEF apparently ignored the existing fuel supply arrangements at Osceola station. The existing fuel supply arrangements are discussed in Mr. Dauer's testimony. Mr. Dauer explains that the combination of firm gas transportation and oil backup would suffice to provide a cost-effective and reliable supply of peaking capacity. Further, Mr. Dauer concluded that the additional firm transportation capacity that DEF had assumed in its evaluation of Acquisition 1 was unnecessary and too costly. Thus, correcting DEF's first error, Acquisition 1 would be about $60 million more cost-effective than is shown in Exhibit___(BMHB-8).

Q IF ACQUISITION 1 HAS SO MANY ADVANTAGES, WHY DID DEF REJECT IT?

A In addition to over-stating the fixed costs, DEF's second error was the assumption that Acquisition 1 could not be consummated because of market power concerns. However, as discussed in Mr. Morris's testimony, these concerns are unfounded. According to Mr. Morris, if the transaction is properly structured, it will pass FERC's Competitive Analysis Screen. Thus, market power is not the risk that DEF asserted it to be and DEF should not have rejected this option outright in favor of its own self-build projects.

Q SHOULD DEF CONTINUE TO PURSUE ACQUISITION 1?

A Yes. Correcting the two errors discussed previously, Acquisition 1 is a viable, low-cost option, and it deserves full and careful consideration.

Q DOES THE FACT THAT ACQUISITION 1 WOULD BE AT LEAST $49 MILLION LESS EXPENSIVE OVER THE NEXT 30 YEARS JUSTIFY SELECTING IT OVER OTHER RESOURCE OPTIONS?

A No, not entirely. Although the results of DEF's cost-effectiveness analysis are instructive, it should be recognized that all models, such as those used in the analysis, are subject to uncertainties, particularly in the later years of an evaluation. Further, a seemingly large difference in NPVRR would translate into only a relatively small rate impact. For example, every $100 million NPVRR over a 30-year planning horizon would affect rates by just $0.08 per 1,000 kWh—a number which could easily fall within the range of a model's accuracy. Thus, the cost-effectiveness analysis should not be the sole deciding factor.

Q HOW SHOULD THE COST-EFFECTIVENESS ANALYSIS BE USED IN DETERMINING THE BEST RESOURCES TO MEET DEF'S CAPACITY NEEDS?

A Recognizing the relative impact and the inherent limitations of any costing model, the Commission should use qualitative criteria in addition to the quantitative cost-effectiveness analysis to determine the resources best suited for meeting DEF's purported capacity needs.

<u>Imputed Debt Adjustment</u>

Q DOES DEF MAKE ANY OTHER ADJUSTMENTS IN DETERMINING THE COST-EFFECTIVENESS OF ALTERNATIVE RESOURCES?

A Yes. DEF asserts that the fixed payments associated with PPAs are the equivalent of a future debt obligation (*i.e.,* "imputed debt"). Accordingly, to maintain the same debt-to-equity ratio, DEF calculates the incremental cost of equity that would be needed to support the imputed debt.[5] This incremental equity cost is added to the other "tangible" costs associated with PPAs.

Q HAVE YOU BEEN ABLE TO DETERMINE SPECIFICALLY HOW DEF CALCULATED THE INCREMENTAL COST OF EQUITY?

A No. Although NRG requested the detailed calculations supporting DEF's evaluation of alternative PPAs, DEF's responses did not reveal how the incremental cost of equity was calculated. This includes the other NRG Production of Documents Requests referenced in DEF's response.[6] Consequently, I reserve the right to supplement my testimony based on discovery requests and responses thereto filed after the testimony due date.

Q IS THE INCREMENTAL EQUITY COST SIGNIFICANT?

~~A~~ Yes. In DEF's cost-effectiveness analysis, the incremental equity cost

[5] Docket No. 140111, Direct Testimony of Benjamin M. H. Borsch at 39.

[6] Docket No. 140111, DEF's Response to NRG's Interrogatory No. 111 and Production of Documents Request No. 20.

associated with PPAs ranged from $175 million to $562 million NPVRR.[7] But for this adjustment, other PPAs (including a PPA with NRG) would have been more cost-effective.

Q DO YOU AGREE WITH DEF'S IMPUTED DEBT ADJUSTMENT?

A No. As discussed below, this adjustment assumes that DEF will incur real costs associated with a long-term PPA, which is not the case. Further, it erroneously assumes that PPAs are the sole cause of a utility's deteriorating credit metrics. Finally, the Commission has previously rejected an imputed debt adjustment for PPAs in past rate cases, including PEF's 2009 rate case.

Q DOES A UTILITY AUTOMATICALLY INCUR ADDITIONAL EQUITY COSTS WHEN IT ENTERS INTO LONG-TERM PURCHASED POWER AGREEMENTS, AS INFERRED BY DEF'S COST-EFFECTIVENESS ANALYSIS?

A No. DEF will not automatically incur additional equity costs to support long-term PPAs. The additional equity cost is purely hypothetical. It is not a real cost.

Q DOES DEF ISSUE ANY ADDITIONAL CAPITAL WHEN IT INCURS OBLIGATIONS UNDER A PURCHASED POWER AGREEMENT?

A No. DEF does not issue either additional debt or equity associated with a PPA. Further, there are no actual PPA-related debt and equity costs under normal regulatory accounting.

[7] Docket No. 140111, Direct Testimony of Benjamin M. H. Borsch at Exhibit ___ (BMHB)-8 (Errata).

Q ARE THERE ANY CIRCUMSTANCES WHEN A UTILITY THAT PURCHASES POWER COULD EXPERIENCE HIGHER BORROWING COSTS?

A Yes. All other things being equal, a lower credit rating would increase DEF's borrowing costs. However, this does not mean that higher borrowing costs are caused by the utility's PPAs and further, it does not mean or imply that DEF would experience higher borrowing costs if it entered a PPA with Acquisition 1.

Q PLEASE EXPLAIN.

A Lower credit ratings reflect the long-term deterioration of a utility's credit metrics. Typically, this happens when the utility is engaged in a major capital spending program that will significantly increase rate base, and it is unable to timely and adequately increase rates to avert a further decline. Higher rates would provide additional cash earnings, which would increase the amount of internally-generated funds available to support construction. In the absence of sufficient internally generated funds, the utility would have to issue substantial amounts of new long-term debt, thereby increasing its financial risk and further jeopardizing financial integrity. If a credit rating agency perceives that the utility will not have the necessary regulatory support to reverse its deteriorating metrics, it might find it necessary to lower the utility's credit rating.

Q WOULD A UTILITY EXPERIENCE HIGHER BORROWING COSTS WHEN IT SIGNS A PURCHASED POWER AGREEMENT?

A No. There is no direct connection between higher borrowing costs and a PPA. Higher borrowing costs would be realized only after a utility's credit rating has been lowered. Further, the increase would also depend on the lower rating assigned by the credit-rating agencies.

Q DO PURCHASED POWER AGREEMENTS ALONE CAUSE A UTILITY'S CREDIT METRICS TO DETERIORATE?

A No. PPAs are an operating expense, not an investment. Thus, there are no financing costs associated with a PPA.

Further, there is little or no credit risk associated with PPAs. For example, under Rule 25-17.0832, Florida Administrative Code, once the Commission has approved a PPA, the utility is allowed full cost recovery. Specifically, purchased power capacity costs are subject to dollar-for-dollar recovery through the Capacity Cost Recovery (CCR) clause. This includes a true-up procedure that establishes a forward-looking charge, which is then reconciled based on actually incurred costs, with interest. The recovery mechanism is nearly identical to DEF's Fuel Charge. Though the costs incurred under Commission-approved PPAs are reviewed in the annual fuel adjustment proceeding, there is minimal recovery risk associated with PPAs.

Thus, if a utility that also purchases capacity experiences deteriorating credit metrics, the probable cause is an over-reliance on leverage to finance capital improvements.

Q HAS THE COMMISSION PREVIOUSLY RECOGNIZED THE ADDITIONAL EQUITY COST ASSOCIATED WITH IMPUTED DEBT IN DETERMINING A UTILITY'S REVENUE REQUIREMENTS?

A No. The Commission rejected a proposal by Tampa Electric Company (TECO) to impute additional equity in determining its capital structure to recognize the so-called imputed debt associated with PPAs. The Commission stated that:

> The pro forma adjustment to equity proposed by TECO is not an actual equity investment in the utility. If this adjustment is approved for purposes of setting rates in this proceeding, the

> Company would essentially be allowed to earn a risk-adjusted equity return without having actually made the equity investment. The revenue requirement impact of recognizing this pro forma adjustment to equity in the capital structure is approximately $5 million per year.[8]

The Commission also found that:

> Companies with PPAs are not required by the rating agencies to make the pro forma adjustment in question. As the following passage explains, the Standard & Poors' (S&P) practice with respect to PPAs described in witness Gillette's testimony is strictly for the rating agency's own analytical purposes:
>
> We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.[9]

Further, in rejecting TECO’s adjustment, the Commission also held:

> With this proposed adjustment, we find that the Company is attempting to take a portion of S&P's consolidated credit assessment methodology and use it for a purpose it was never intended.[10]

Q WAS A SIMILAR ADJUSTMENT ALSO PROPOSED IN A PRIOR PROGRESS ENERGY FLORIDA RATE CASE?

A Yes. In its 2009 rate case (Docket No. 090079-EI), PEF also proposed adjusting its equity ratio to reflect the amount of equity necessary to offset the effect of the

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[8] *In re: Petition for rate increase by Tampa Electric Company*, Docket No. 080317-EI, Final Order Granting in Part and Denying in Part Petition for Rate Increase (Apr. 30, 2009) at 35.

[9] *Id.*

[10] *Id*. at 36.

imputed debt associated with long-term PPAs. This adjustment had the effect of increasing PEF's equity ratio as a percentage of investor capital from 50.3 percent to 53.9 percent. The annual revenue requirement impact of this adjustment was $24.7 million.[11]

Q WAS PROGRESS ENERGY FLORIDA'S IMPUTED DEBT ADJUSTMENT ACCEPTED?

A No. PEF's imputed debt adjustment was rejected. In rejecting the adjustment, the Commission stated:

> PEF witness Sullivan acknowledged that, given the cost recovery mechanism in Florida and the fact that PEF has never been denied recovery of PPA costs, there is a very low risk of non-recovery of PPA costs. He also agreed that Moody's does not make an explicit adjustment for PPAs like S&P does and that there is no guarantee PEF's bond rating would be upgraded by any rating agency if this pro forma adjustment were approved for rate setting purposes. Witness Sullivan acknowledged that the proposed pro forma adjustment is not consistent with GAAP accounting. He also agreed that the Commission recently denied a request by TECO for a similar adjustment in its rate case. Finally, witness Sullivan agreed that, while the 2005 Stipulation included a pro forma adjustment to PEF's capital structure for ratemaking purposes to account for S&P's methodology related to the treatment of PPAs, said approval did not constitute binding precedent in any future proceeding.
>
> Based on the record evidence and for the reasons discussed above, we find that PEF's requested pro forma adjustment to equity shall be denied for purposes of setting rates in this proceeding. Thus, the $711 million (system) adjustment shall be removed from the capital structure through a specific adjustment to common equity on a system basis.[12]

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[11] *In re: Petition for increase in rates by Progress Energy Florida, Inc.,* Docket No. 090079-EI, Order No. PSC-l0-0131-FOF-EI, (Mar. 5, 2010), at 74-76.

[12] *Id.*

Q SHOULD ADDITIONAL EQUITY COSTS BE INCLUDED IN EVALUATING THE COST-EFFECTIVENESS OF PURCHASED POWER AGREEMENTS?

A No. For all of the reasons stated above, additional equity costs should not be included in evaluating the merits of PPAs as alternatives to DEF's proposed self-build projects. Thus, the Commission should reject this component of DEF's cost-effectiveness analysis.

<u>Qualitative Assessment</u>

Q WHAT QUALITATIVE CRITERIA SHOULD BE USED IN ASSESSING DEF'S RESOURCE OPTIONS?

A The proposed self-build projects are predicated on the assumption that DEF needs additional capacity prior to 2018. The need for capacity, in turn, is predicated on a load forecast that assumes DEF will experience significant load growth, particularly in the next several years. However, load could grow faster or slower than DEF is projecting. If load growth exceeds DEF's projections, it may not have sufficient capacity to meet the 20% reserve margin criterion established by the Commission. Alternatively, if load growth fails to materialize, customers will be saddled with excess capacity and higher electricity rates. Thus, in evaluating DEF's capacity additions, the Commission must balance both the costs and risks (such as load forecasting error) because ultimately, regardless of the resource selected, DEF's customers will pay the associated costs.

Q ARE THERE ANY OTHER QUALITATIVE CRITERIA THE COMMISSION SHOULD USE IN ASSESSING DEF'S SELF-BUILD PROPOSALS?

A Yes. The self-build projects proposed in these two dockets represent an *"extreme makeover"* of DEF's generation fleet. As discussed later, this makeover will cause very significant upward pressure on DEF's already high electricity rates. Thus, DEF's proposal should be evaluated not just in terms of the impact on rates associated with the self-build projects. The Commission must also consider the broader rate impact—*i.e.*, the potential consequences of exacerbating what are already among the highest electric rates in Florida and the Southeast.

Q WHY DO YOU CHARACTERIZE THE TRANSFORMATION OF DEF'S GENERATION FLEET AS AN EXTREME MAKEOVER?

A The proposed transformation will essentially replace DEF's older facilities with newer more modern ones. As discussed later, it will require retail electric rates to support more than $4 billion of capital to supply less than 200 MW of additional generation capacity.

Q WHAT ARE THE PRIMARY COMPONENTS OF THE EXTREME MAKEOVER?

A The extreme makeover of DEF's generation fleet is comprised of three primary components.

First, in February 2013, DEF announced that it was retiring Crystal River Unit No. 3 (CR3), DEF's only operating nuclear plant. CR3 provided 850 MW of base load capacity. Recently, in Docket No. 130208-EI the Commission approved a Settlement (2013 Settlement) that addressed the recovery of the remaining cost of CR3.[13] The same Settlement also addressed the cancellation of the Engineering, Procurement and Construction (EPC) contract associated

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[13] *In re: Petition for Limited Proceeding to Approve Revised and Restated Stipulation and Settlement Agreement by Duke Energy Florida, Inc, d/b/a Duke Energy*; Docket No. 130208 EI, Final Order Approving Revised and Restated Stipulation and Settlement Agreement (Nov. 12, 2013).

with the proposed Levy Nuclear Plant (Levy). As discussed later, the terms of the Settlement that pertain to both CR3 and Levy will affect future electricity rates.

Second, DEF has also decided to retire two large coal units at Crystal River Units 1 and 2, also known as CR South. These units provide about 869 MW of base load capacity. Originally, CR South was going to be retired in 2015 to comply with the EPA's MATS Rule, but their retirement was extended to 2018. As the condition for extending operation past 2015, the CR South units will be derated by 129 MW in 2016.[14]

Third, DEF is also proposing to "modernize" its natural gas fleet. If approved by the Commission, DEF's rates will reflect "modernization costs" of:

- Retiring the oldest CTs at Avon Park, Turner and Rio Pinar by 2016 (133 MW of summer generation capacity)[15];
- Accelerating the retirement of the three Suwannee steam units from 2018 to 2016 (128 MW of summer generation capacity)[16];
- Replacing the existing Suwannee units with the proposed CTs, which will provide up to 316 MW of summer generation capacity)[17];
- The Hines Chiller Uprate (220 MW)[18]; and
- The proposed Citrus County combined cycle project (1,640 MW)[19].

The table below summarizes DEF's planned retirements and modernization proposals. As can be seen, the extreme makeover of DEF's generation fleet

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[14] Docket No. 140111, DEF's Response to NRG Interrogatory No. 47.

[15] *Id.* and Exhibit ___(BMHB-2) at 11.

[16] Docket No. 140111, DEF's Response to NRG Interrogatory No. 47.

[17] *Id.*

[18] *Id.*

[19] *Id.*

would produce less than 200 MW of additional capacity.

Net Capacity Changes (Summer MW)[20]			
Year	**Addition**	**Retirement**	**Cumulative Impact**
2013		850	-850
2014		53	-903
2016	316	338	-925
2017	220	0	-705
2018	820	740	-625
2019	820	0	195

Q HOW SHOULD THE RISKS ASSOCIATED WITH THIS EXTREME MAKEOVER OF DEF'S GENERATION FLEET BE MANAGED?

A To manage these risks, the resources selected in these proceedings should:

- Not provide more than the minimum amount of needed capacity;
- Preserve flexibility in the event of load forecasting error (*i.e.,* either higher or lower than anticipated growth);
- Minimize DEF's future capital commitment; and
- Have the least impact on rates.

Q WHY IS LOAD FORECASTING ERROR A SIGNIFICANT RISK?

A DEF's need for capacity prior to 2018 is largely driven by a more than 1,000 MW increase in both wholesale and peak demand in 2014-2015. This is by far more load growth than DEF has experienced in two consecutive years since 2005. Thus, there is a significant risk that load growth could be far less than DEF anticipates.

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[20] Docket No. 140111, DEF's Response to NRG Interrogatory No. 47 and Exhibit ___(BMHB-2) at 11.

Q HAVE YOU PREPARED AN ILLUSTRATION SHOWING THE POTENTIAL RISK OF LOAD FORECASTING ERROR?

A Yes. **Exhibit___(JP-2)** illustrates how load forecasting error (in this case, lower-than-anticipated load growth) would affect DEF's projected firm summer peak demand over the period 2014 through 2023. Specifically, I quantified the summer peak demand assuming only 50% of DEF's projected load growth materializes (the blue bars) and compared this to DEF's load growth projections (the blue/pink bars). As can be seen, if load growth is only 50% of DEF's projections, DEF's firm summer peak demand would be between 400 MW and 1,083 MW lower in the 2014-2023 timeframe.

Q HOW WOULD LOAD FORECASTING ERROR AFFECT DEF'S PROJECTED CAPACITY NEEDS?

A DEF's projected capacity needs are based on achieving a *minimum* 20% reserve margin relative to projected firm summer peak demand. Thus, the lower the projected firm summer peak demand, the lower the amount of needed capacity.

Q HOW MUCH OF DEF'S PLANNED CAPACITY ADDITIONS WOULD NOT BE NEEDED IF IT EXPERIENCED ONLY 50% OF THE PROJECTED LOAD GROWTH?

A DEF would be significantly over-built in the years 2016 and 2017. This is shown in **Exhibit___(JP-3)**. As can be seen, DEF's capacity needs would be 844 MW and 915 MW less in the years 2016 and 2017, respectively.

Q WHAT IS THE CONSEQUENCE OF BUILDING NEW CAPACITY THAT IS SURPLUS TO DEF'S CAPACITY NEEDS?

A The consequence is that DEF's retail electricity rates will be significantly higher during the period of surplus capacity. This is because DEF will experience higher costs, but these higher costs would be spread over fewer billing units. Further, these rates will remain higher until load has grown to a level that more closely matches DEF's installed capacity. This would, in turn, raise rates further, thus encouraging slower sales growth.

Q IS IT ALSO POSSIBLE THAT LOAD GROWTH COULD BE HIGHER THAN DEF ANTICIPATES?

A Yes. If DEF has understated its projected firm summer peak demand, then the system would be under-built, all other things being equal.

Q HOW CAN THE RISK OF LOAD FORECASTING ERROR BE ADDRESSED IN THE EVENT THAT DEF EXPERIENCES HIGHER-THAN-ANTICIPATED GROWTH?

A There are several actions that DEF could individually or collectively take to hedge load forecasting error while maintaining system reliability. These actions include:

- Acquiring capacity from the resources offered in Acquisition 1 and/or Acquisition 2;
- Entering into firm PPAs with Acquisitions 1 and/or 2 or other Florida utilities with surplus capacity; and
- Deferring the retirement of DEF's older gas generators.

Q WHICH OF THE ABOVE OPTIONS WOULD BE BETTER FOR DEF'S CUSTOMERS?

A Consistent with the criteria presented earlier, Acquisition 1 would offer lower cost, less risk, and greater flexibility than DEF's proposed self-build projects. First, as previously discussed, Acquisition 1 is more cost-effective than the proposed self-build projects. Second, the combination of Acquisition 1 and the Hines Chiller Uprate would provide about 690 MW. This compares to only 408 MW of net additional capacity by pursuing both the Suwannee CTs and Hines Chiller Projects because DEF would lose about 128 MW of capacity by retiring the existing Suwannee units. Third, if the projected 2014-2015 load growth fails to materialize, the Hines Chiller Project could be deferred.

In summary, Acquisition 1 has the advantages of lower cost, greater flexibility and lower risk than the Suwannee/Hines self-build projects.

Q HOW WOULD ACQUISITION 1 REDUCE DEF'S FUTURE CAPITAL COMMITMENTS?

A The Suwannee/Hines self-build projects would commit ratepayers to paying an estimated $357 million of additional capital costs over the estimated 35 and 29-year lives, respectively, of these facilities. Acquisition 1 would require less capital commitment. Further, there is no risk of a cost over-run (because the purchase price, terms and conditions would be firmly established up-front), and the facility has provided a reliable supply of power to other Florida electric utilities, including DEF's predecessor, Progress Energy Florida. Minimizing capital commitments is important because DEF's customers are already facing higher rates to provide for the recovery of $2.1 billion of capital costs associated with DEF's retired/retiring generation facilities over the next 23 years.

Q WHAT CAPITAL COSTS WILL DEF'S CUSTOMERS BE RESPONSIBLE FOR IN FUTURE ELECTRICITY RATES?

A DEF can seek the recovery of the capital costs shown in **Exhibit___(JP-4)** pursuant to the terms of the 2013 Settlement. Lines 1-10 show the capital items related to the retirement of existing generation facilities. As can be seen, that commitment alone could exceed $2.1 billion. The projects comprising the $2.1

billion capital recovery are summarized in the table below.

Capital Recovery of Existing Generation Assets Pursuant to the 2013 Rate Settlement		
Item	**Amount ($Millions)**	**Date Cost Recovery To Commence**
Point of Discharge Cooling Towers	$18	Jan. 2013
CR3	Up to $1,466	Jan. 2017
CR3 EPU	$323	2013-2019
CR3 Dry Cask Storage	TBD	Jan. 2017
Levy EPC Contract Cancelation	$350	2013-2017
CR South Remaining Book Value	TBD	Jan. 2021

Q **ARE THESE THE ONLY COMMITMENTS THAT DEF'S RETAIL CUSTOMERS ARE OBLIGATED TO FUND IN FUTURE ELECTRICITY RATES?**

A No. The 2013 Settlement also addressed the ratemaking treatment of any new generation resources that might be approved in these proceedings. As can be seen in **Exhibit___(JP-4),** beginning on line 11, the self-build projects that DEF is proposing in these proceedings are estimated to cost $1.87 billion, assuming that any cost over-runs are not incurred or allowed to be included in rates.

Thus, the extreme makeover of DEF's generation fleet, if approved for cost recovery by the Commission, could result in a total capital recovery of over $4.0 billion. To put this in context, in its 2009 rate case (D-090079-EI), the Commission found that PEF's rate base was $6.3 billion, including CR3. Thus, the proposed $4 billion capital recovery would exceed 60% of its rate base.

Q DOES THE $4 BILLION INCLUDE ALL PROJECTED CAPITAL RECOVERY THAT WILL HAVE TO BE SUPPORTED IN DEF'S ELECTRICITY RATES?

A No. The $4 billion of capital recovery is associated only with the extreme makeover of DEF's generation fleet. It does not include generation capacity additions after 2018 or any transmission, distribution or other plant additions to accommodate load growth, attach new customers, modernization, and replacement.

Q HOW WILL FUTURE CAPITAL RECOVERY AFFECT RATES?

A Electricity rates include all of the costs associated with future capital recovery, which include:

- Incremental non-fuel operation and maintenance expenses associated with new generation, transmission and distribution, and general plant;
- Return on investment;
- Depreciation expense;
- Property taxes; and
- State and federal income taxes.

Q WHY SHOULD THE COMMISSION ALSO BE CONCERNED ABOUT THE RATE IMPACTS ASSOCIATED WITH DEF'S EXTREME GENERATION MAKEOVER?

A DEF's electricity rates are already among the highest in Florida and in nearby southeastern states. This is demonstrated in **Exhibit___(JP-5)**, which shows typical electricity rates for customers served by investor-owned electric utilities (IOUs), including DEF (the red bars) and other Florida IOUs (the blue bars) based on rates in effect on January 1, 2014. The rate comparisons include:

- Page 1: Residential 1,000 kWh per month;
- Page 2: Small Commercial 40 kW at 48% load factor;

- Page 3: Large Commercial 500 kW at 49% load factor; and
- Page 4: Industrial 1,000 kW at 89% load factor.

A similar comparison for rates in effect as of July 2013, is provided in **Exhibit___(JP-6)**. Both exhibits were prepared from data provided by the Edison Electric Institute.

As can be seen in **Exhibits___(JP-5)** and **(JP-6),** even before the extreme makeover of DEF's generation fleet, DEF's electricity rates are among the highest of the Florida IOUs. This makes DEF's planned makeover of its generation fleet not only costly, but risky. The risk is that DEF's rates will increase if projected load growth fails to materialize. This is because DEF would incur the higher costs of the capacity additions, but these costs would be spread over a lower sales base. Higher electricity rates can also be expected to constrain load growth, thus increasing the probability that rates could spiral even higher.

<u>Conclusions and Recommendation</u>

Q BASED ON YOUR ANALYSIS OF DEF'S FILED TESTIMONY AND RESPONSES TO VARIOUS DISCOVERY REQUESTS, WHAT CONCLUSIONS HAVE YOU DRAWN?

A DEF's proposed extreme makeover of its generation assets, including the recovery of costs associated with retiring generation assets (*e.g.*, CR3, CR South, older gas units) and with its proposed self-build generation projects (*e.g.* Suwannee CTs, Hines Chiller Uprate and Citrus County combined cycle gas turbines) will commit customers to paying over $4 billion for less than 200 MW of new capacity. With DEF's current electricity rates already among the highest among IOUs in Florida and in surrounding states, DEF's customers can ill-afford the high price tag. Further, if DEF proceeds with its self-build projects and the substantial projected load growth fails to materialize, rates would spiral further upwards in a self-sustaining customer reaction to high electricity rates (*i.e.,* the "death spiral"). This is too great a risk to impose on DEF's customers for the little benefit received.

Therefore, based on the lower projected costs, lower rate impact, greater flexibility and lower risk, Acquisition 1 is clearly a better choice for DEF's customers. For all of these reasons, DEF's request in this proceeding should be denied.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

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PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
131002	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Rebuttal	MN	Class Cost-of-Service Study, Class Revenue Allocation	7/7/2014
140303	PPL ELECTRIC UTILITIES CORPORATION	PP&L Industrial Customer Alliance	2013-2398440	Rebuttal	PA	Energy Efficiency Cost Recovery	7/1/2014
131002	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Direct	MN	Revenue Requirements, Fuel Clause Rider, Class Cost-of-Service Study, Rate Design and Revenue Allocation	6/5/2014
140303	PPL ELECTRIC UTILITIES CORPORATION	PP&L Industrial Customer Alliance	2013-2398440	Direct	PA	Energy Efficiency Cost Recovery	5/23/2014
140105	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	42042	Direct	TX	Transmission Cost Recovery Factor	4/24/2014
130901	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41791	Cross	TX	Class Cost-of-Service Study and Rate Design	1/31/2014
130901	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41791	Direct	TX	Revenue Requirements, Fuel Reconciliation; Cost Allocation Issues; Rate Design Issues	1/10/2014
131005	DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Supplemental Surrebuttal	PA	Class Cost-of-Sevice Study	12/13/2013
131005	DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Surrebuttal	PA	Class Cost-of-Service Study; Cash Working Capital; Miscellaneous General Expense; Uncollectable Expense; Class Revenue Allocation	12/9/2013
131005	DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Rebuttal	PA	Rate L Transmission Service; Class Revenue Allocation	11/26/2013
130905	ENTERGY TEXAS, INC. ITC HOLDINGS CORP.	Texas Industrial Energy Consumers	41850	Direct	TX	Rate Mitigation Plan; Conditions re Transfer of Control of Ownership	11/6/2013
130501	MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Surrebuttal	IA	Class Cost-of-Service Study; Class Revenue Allocation; Depreciation Surplus	11/4/2013
130602	SHARYLAND UTILITIES	Texas Inustrial Energy Consumers and Atlas Pipeline Mid-Continent WestTex, LLC	41474	Cross-Rebuttal	TX	Customer Class Definitions; Class Revenue Allocation; Allocation of TTC costs	11/4/2013
131005	DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Direct	PA	Class Cost-of-Service, Class Revenue Allocations	11/1/2013
130906	PUBLIC SERVICE ENERGY AND GAS	New Jersey Large Energy Users Coalition	EO13020155 and GO13020156	Direct	NJ	Energy Strong	10/28/2013
130602	SHARYLAND UTILITIES	Texas Inustrial Energy Consumers and Atlas Pipeline Mid-Continent WestTex, LLC	41474	Direct	TX	Regulatory Asset Cost Recovery; Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	10/18/2013
130903	GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Association of Manufacturers	36989	Direct	GA	Depreciation Expense, Alternate Rate Plan, Return on Equity, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	10/18/2013

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130501	MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Rebutal	IA	Class Cost-of-Service Study	10/1/2013
130902	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	130007	Direct	FL	Environmental Cost Recovery Clause	9/13/2013
130501	MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Direct	IA	Class Cost-of-Service Study, Class Revenue Allocation, Depreciation, Cost Recovery Clauses, Revenue Sharing, Revenue True-up	9/10/2013
130202	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	12-00350-UT	Rebuttal	NM	RPS Cost Rider	9/9/2013
130701	WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	13-WSEE-629-RTS	Cross-Answering	KS	Cost Allocation Methodology	9/5/2013
130202	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	12-00350-UT	Direct	NM	Class Cost-of-Service Study	8/22/2013
130701	WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	13-WSEE-629-RTS	Direct	KS	Class Revenue Allocation.	8/21/2013
130203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41437	Direct	TX	Avoided Cost; Standby Rate Design	8/14/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-699	Direct	KS	Class Revenue Allocation	8/12/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Supplemental	KS	Testimony in Support of Settlement	8/9/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Supplemental	KS	Modification Agreement	7/24/2013
130201	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	130040	Direct	FL	GSD-IS Consolidation, GSD and IS Rate Design, Class Cost-of-Service Study, Planned Outage Expense, Storm Damage Expense	7/15/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Supplemental	KS	Testimony in Support of Nonunanimous Settlement	6/28/2013
121203	JERSEY CENTRAL POWER & LIGHT COMPANY	Gerdau Ameristeel Sayreville, Inc.	ER12111052	Direct	NJ	Cost of Service Study for GT-230 KV Customers; AREP Rider	6/14/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Direct	KS	Wholesale Requirements Agreement; Process for Exemption From Regulation; Conditions Required for Public Interest Finding on CCN spin-down	5/14/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Cross	KS	Formula Rate Plan for Distribution Utility	5/10/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Direct	KS	Formula Rate Plan for Distribution Utility	5/3/2013
121001	ENTERGY TEXAS, INC. ITC HOLDINGS CORP.	Texas Industrial Energy Consumers	41223	Direct	TX	Public Interest of Proposed Divestiture of ETI's Transmission Business to an ITC Holdings	4/30/2013
121101	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Surrebuttal	MN	Depreciation; Used and Useful; Cost Allocation; Revenue Allocation	4/12/2013
121101	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Rebuttal	MN	Class Revenue Allocation.	3/25/2013

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121101	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Direct	MN	Depreciation; Used and Useful; Property Tax; Cost Allocation; Revenue Allocation; Competitive Rate & Property Tax Riders	2/28/2013
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Second Supplemental Rebuttal	TX	Competitive Generation Service Tariff	2/1/2013
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Second Supplemental Direct	TX	Competitive Generation Service Tariff	1/11/2013
110202	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	40443	Cross Rebuttal	TX	Cost Allocation and Rate Design	1/10/2013
110202	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	40443	Direct	TX	Application of the Turk Plant Cost-Cap; Revenue Requirements; Class Cost-of-Service Study; Class Revenue Allocation; Industrial Rate Design	12/10/2012
120301	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Corrected Supplemental Rebuttal	FL	Support for Non-Unanimous Settlement	11/13/2012
120301	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Corrected Supplemental Direct	FL	Support for Non-Unanimous Settlement	11/13/2012
120602	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	12-E-0201/12-G-0202	Rebuttal	NY	Electric and Gas Class Cost-of-Service Studies.	9/25/2012
120602	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	12-E-0201/12-G-0202	Direct	NY	Electric and Gas Class Cost-of-Service Study; Revenue Allocation; Rate Design; Historic Demand	8/31/2012
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	12-MKEE-650-TAR	Direct	KS	Transmission Formula Rate Plan	7/31/2012
120502	WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	12-WSEE-651-TAR	Direct	KS	TDC Tariff	7/30/2012
120301	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Direct	FL	Class Cost-of-Service Study, Revenue Allocation, and Rate Design	7/2/2012
120101	LONE STAR TRANSMISSION, LLC	Texas Industrial Energy Consumers	40020	Direct	TX	Revenue Requirement, Rider AVT	6/21/2012
111102	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39896	Cross	TX	Class Cost-of-Service Study, Revenue Allocation, and Rate Design	4/13/2012
111102	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39896	Direct	TX	Revenue Requirements, Class Cost-of-Service Study, Revenue Allocation, and Rate Design	3/27/2012
91023	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Supplemental Rebuttal	TX	Competitive Generation Service Issues	2/24/2012
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Supplemental Direct	TX	Competitive Generation Service Issues	2/10/2012
101101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	39722	Direct	TX	Carrying Charge Rate Applicable to the Additional True-Up Balance and Tax Balances	11/4/2011
110703	GULF POWER COMPANY	Florida Industrial Power Users Group	110138-EI	Direct	FL	Cost Allocation and Storm Reserve	10/14/2011

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90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39504	Direct	TX	Carrying Charge Rate Applicable to the Additional True-Up Balance and Taxes	9/12/2011
101101	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
101101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	39360	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
100503	ONCOR ELECTRIC DELIVERY COMPANY, LLC	Texas Industrial Energy Consumers	39375	Direct	TX	Energy Efficiency Cost Recovery Factor	8/2/2011
90103	ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	31653	Direct	AL	Renewable Purchased Power Agreement	7/28/2011
101101	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Direct	TX	Energy Efficiency Cost Recovery Factor	7/26/2011
101101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	36360	Direct	TX	Energy Efficiency Cost Recovery Factor	7/20/2011
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39366	Direct	TX	Energy Efficiency Cost Recovery Factor	7/19/2011
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39363	Direct	TX	Energy Efficiency Cost Recovery Factor	7/15/2011
101201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Surrebuttal	MN	Depreciation; Non-Asset Margin Sharing; Step-In Increase; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	5/26/2011
101201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Rebuttal	MN	Classification of Wind Investment	5/4/2011
101201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Direct	MN	Surplus Depreciation Reserve, Incentive Compensation, Non-Asset Trading Margin Sharing, Cost Allocation, Class Revenue Allocation, Rate Design	4/5/2011
101202	ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-381-EA-10	Direct	WY	2010 Protocols	2/11/2011
100802	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	38480	Direct	TX	Cost Allocation, TCRF	11/8/2010
90402	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	31958	Direct	GA	Alternate Rate Plan, Return on Equity, Riders, Cost-of-Service Study, Revenue Allocation, Economic Development	10/22/2010
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	38339	Cross-Rebuttal	TX	Cost Allocation, Class Revenue Allocation	9/24/2010
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	38339	Direct	TX	Pension Expense, Surplus Depreciation Reserve, Cost Allocation, Rate Design, Riders	9/10/2010
100303	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	10-E-0050	Rebuttal	NY	Multi-Year Rate Plan, Cost Allocation, Revenue Allocation, Reconciliation Mechanisms, Rate Design	8/6/2010

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100303	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	10-E-0050	Direct	NY	Multi-Year Rate Plan, Cost Allocation, Revenue Allocation, Reconciliation Mechanisms, Rate Design	0714/2010
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37744	Cross Rebuttal	TX	Cost Allocation, Revenue Allocation, CGS Rate Design, Interruptible Service	6/30/2010
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37744	Direct	TX	Class Cost of Service Study, Revenue Allocation, Rate Design, Competitive Generation Services, Line Extension Policy	6/9/2010
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37482	Cross Rebuttal	TX	Allocation of Purchased Power Capacity Costs	2/3/2010
90402	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	28945	Direct	GA	Fuel Cost Recovery	1/29/2010
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37482	Direct	TX	Purchased Power Capacity Cost Factor	1/22/2010
90403	VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00081	Direct	VA	Allocation of DSM Costs	1/13/2010
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37580	Direct	TX	Fuel refund	12/4/2009
90403	VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00019	Direct	VA	Standby rate design; dynamic pricing	11/9/2009
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	37135	Direct	TX	Transmission cost recovery factor	10/22/2009
80703	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	09-MKEE-969-RTS	Direct	KS	Revenue requirements, TIER, rate design	10/19/2009
90601	VARIOUS UTILITIES	Florida Industrial Power Users Group	090002-EG	Direct	FL	Interruptible Credits	10/2/2009
80505	ONCOR ELECTRIC DELIVERY COMPANY	Texas Industrial Energy Consumers	36958	Cross Rebuttal	TX	2010 Energy efficiency cost recovery factor	8/18/2009
81001	PROGRESS ENERGY FLORIDA	Florida Industrial Power Users Group	90079	Direct	FL	Cost-of-service study, revenue allocation, rate design, depreciation expense, capital structure	8/10/2009
90404	CENTERPOINT	Texas Industrial Energy Consumers	36918	Cross Rebuttal	TX	Allocation of System Restoration Costs	7/17/2009
90301	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	080677	Direct	FL	Depreciation; class revenue allocation; rate design; cost allocation; and capital structure	7/16/2009
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	36956	Direct	TX	Approval to revise energy efficiency cost recovery factor	7/16/2009
90601	VARIOUS UTILITIES	Florida Industrial Power Users Group	VARIOUS DOCKETS	Direct	FL	Conservation goals	7/6/2009
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	36931	Direct	TX	System restoration costs under Senate Bill 769	6/30/2009
90502	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	36966	Direct	TX	Authority to revise fixed fuel factors	6/18/2009
80805	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	36025	Cross-Rebuttal	TX	Cost allocatiion, revenue allocation and rate design	6/10/2009

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80805	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	36025	Direct	TX	Cost allocation, revenue allocation, rate design	5/27/2009
81201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Surrebuttal	MN	Cost allocation, revenue allocation, rate design	5/27/2009
90403	VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00018	Direct	VA	Transmission cost allocation and rate design	5/20/2009
90101	NORTHERN INDIANA PUBLIC SERVICE COMPANY	Beta Steel Corporation	43526	Direct	IN	Cost allocation and rate design	5/8/2009
81203	ENTERGY SERVICES, INC	Texas Industrial Energy Consumers	ER008-1056	Rebuttal	FERC	Rough Production Cost Equalization payments	5/7/2009
81201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Rebuttal	MN	Class revenue allocation and the classification of renewable energy costs	5/5/2009
81201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Direct	MN	Cost-of-service study, class revenue allocation, and rate design	4/7/2009
81203	ENTERGY SERVICES, INC	Texas Industrial Energy Consumers	ER08-1056	Answer	FERC	Rough Production Cost Equalization payments	3/6/2009
80901	ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-333-ER-08	Direct	WY	Cost of service study; revenue allocation; inverted rates; revenue requirements	1/30/2009
81203	ENTERGY SERVICES	Texas Industrial Energy Consumers	ER08-1056	Direct	FERC	Entergy's proposal seeking Commission approval to allocate Rough Production Cost Equalization payments	1/9/2009
80505	ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	35717	Cross Rebuttal	TX	Retail transformation; cost allocation, demand ratchet waivers, transmission cost allocation factor	12/24/2008
70101	GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Traditional Manufacturers Association	27800	Direct	GA	Cash Return on CWIP associated with the Plant Vogtle Expansion	12/19/2008
80505	ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	35717	Direct	TX	Revenue Requirement, class cost of service study, class revenue allocation and rate design	11/26/2008
80802	TAMPA ELECTRIC COMPANY	The Florida Industrial Power Users Group and Mosaic Company	080317-EI	Direct	FL	Revenue Requirements, retail class cost of service study, class revenue allocation, firm and non firm rate design and the Transmission Base Rate Adjustment	11/26/2008
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Supplemental Direct	TX	Recovery of Energy Efficiency Costs	11/6/2008
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Cross-Rebuttal	TX	Cost Allocation, Demand Ratchet, Renewable Energy Certificates (REC)	10/28/2008

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PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Direct	TX	Revenue Requirements, Fuel Reconciliation Revenue Allocation, Cost-of-Service and Rate Design Issues	10/13/2008
50106	ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	18148	Direct	AL	Energy Cost Recovery Rate (WITHDRAWN)	9/16/2008
50701	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	35269	Direct	TX	Allocation of rough production costs equalization payments	7/9/2008
70703	ENTERGY GULF STATES UTILITIES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Non-Unanimous Stipulation	6/11/2008
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Supplemental Rebuttal	TX	Transmission Optimization and Ancillary Services Studies	6/3/2008
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Supplemental Direct	TX	Transmission Optimization and Ancillary Services Studies	5/23/2008
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	33891	Supplemental Direct	TX	Certificate of Convenience and Necessity	5/8/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Cross-Rebuttal	TX	Cost Allocation and Rate Design and Competitive Generation Service	4/18/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Eligible Fuel Expense	4/11/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Competitive Generation Service Tariff	4/11/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Revenue Requirements	4/11/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Cost of Service study, revenue allocation, design of firm, interruptible and standby service tariffs; interconnection costs	4/11/2008
41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	35038	Rebuttal	TX	Over $5 Billion Compliance Filing	4/14/2008
60303	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	26794	Direct	GA	Fuel Cost Recovery	4/15/2008
71202	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd.	07-00319-UT	Rebuttal	NM	Revenue requirements, cost of service study, rate design	3/28/2008
61101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	35105	Direct	TX	Over $5 Billion Compliance Filing	3/20/2008
51101	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	32902	Direct	TX	Over $5 Billion Compliance Filing	3/20/2008
71202	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd.	07-00319-UT	Direct	NM	Revenue requirements, cost of service study (COS); rate design	3/7/2008
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	34724	Direct	TX	IPCR Rider increase and interim surcharge	11/28/2007
70601	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	25060-U	Direct	GA	Return on equity; cost of service study; revenue allocation; ILR Rider; spinning reserve tariff; RTP	10/24/2007
70303	ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	34077	Direct	TX	Acquisition; public interest	9/14/2007
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	33891	Direct	TX	Certificate of Convenience and Necessity	8/30/2007
61201	ALTAMAHA ELECTRIC MEMBERSHIP CORPORATION	SP Newsprint Company	25226-U	Rebuttal	GA	Discriminatory Pricing; Service Territorial Transfer	7/17/2007

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61201	ALTAMAHA ELECTRIC MEMBERSHIP CORPORATION	SP Newsprint Company	25226-U	Direct	GA	Discriminatory Pricing; Service Territorial Transfer	7/6/2007
70502	PROGRESS ENERGY FLORIDA	Florida Industrial Power Users Group	070052-EI	Direct	FL	Nuclear uprate cost recovery	6/19/2007
70603	ELECTRIC TRANSMISSION TEXAS LLC	Texas Industrial Energy Consumers	33734	Direct	TX	Certificate of Convenience and Necessity	6/8/2007
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Rebuttal Remand	TX	Interest rate on stranded cost reconciliation	6/15/2007
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Remand	TX	Interest rate on stranded cost reconciliation	6/8/2007
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Rebuttal	TX	CREZ Nominations	5/21/2007
50701	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	33687	Direct	TX	Transition to Competition	4/27/2007
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Direct	TX	CREZ Nominations	4/24/2007
61101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	33309	Cross-Rebuttal	TX	Cost Allocation,Rate Design, Riders	4/3/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32710	Cross-Rebuttal	TX	Fuel and Rider IPCR Reconcilation	3/16/2007
61101	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	33310	Direct	TX	Cost Allocation,Rate Design, Riders	3/13/2007
61101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	33309	Direct	TX	Cost Allocation,Rate Design, Riders	3/13/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32710	Direct	TX	Fuel and Rider IPCR Reconcilation	2/28/2007
41219	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	31461	Direct	TX	Rider CTC design	2/15/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	33586	Cross-Rebuttal	TX	Hurricane Rita reconstruction costs	1/30/2007
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	32898	Direct	TX	Fuel Reconciliation	1/29/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	33586	Direct	TX	Hurricane Rita reconstruction costs	1/18/2007
60303	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	23540-U	Direct	GA	Fuel Cost Recovery	1/11/2007
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Cross Rebuttal	TX	Cost allocation, Cost of service, Rate design	1/8/2007
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Cost allocation, Cost of service, Rate design	12/22/2006
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Revenue Requirements,	12/15/2006
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Fuel Reconcilation	12/15/2006
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32907	Cross Rebuttal	TX	Hurricane Rita reconstruction costs	10/12/06
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32907	Direct	TX	Hurricane Rita reconstruction costs	10/09/06
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Cross Rebuttal	TX	Stranded Cost Reallocation	09/07/06
60101	COLQUITT EMC	ERCO Worldwide	23549-U	Direct	GA	Service Territory Transfer	08/10/06
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Direct	TX	Stranded Cost Reallocation	08/23/06
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	32672	Direct	TX	ME-SPP Transfer of Certificate to SWEPCO	8/23/2006

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50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	32758	Direct	TX	Rider CTC design and cost recovery	08/24/06
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32685	Direct	TX	Fuel Surcharge	07/26/06
60301	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	171406	Direct	NJ	Gas Delivery Cost allocation and Rate design	06/21/06
60303	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	22403-U	Direct	GA	Fuel Cost Recovery Allowance	05/05/06
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	32475	Cross-Rebuttal	TX	ADFIT Benefit	04/27/06
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	32475	Direct	TX	ADFIT Benefit	04/17/06
41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	31994	Cross-Rebuttal	TX	Stranded Costs and Other True-Up Balances	3/16/2006
41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	31994	Direct	TX	Stranded Costs and Other True-Up Balances	3/10/2006
50303	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	ER05-168-001	Direct	NM	Fuel Reconciliation	3/6/2006
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31544	Cross-Rebuttal	TX	Transition to Competition Costs	01/13/06
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31544	Direct	TX	Transition to Competition Costs	01/13/06
50601	PUBLIC SERVICE ELECTRIC AND GAS COMPANY AND EXELON CORPORATION	New Jersey Large Energy Consumers Retail Energy Supply Association	BPU EM05020106 OAL PUC-1874-05	Surrebuttal	NJ	Merger	12/22/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	EL05-19-002; ER05-168-001	Responsive	FERC	Fuel Cost adjustment clause (FCAC)	11/18/2005
50601	PUBLIC SERVICE ELECTRIC AND GAS COMPANY AND EXELON CORPORATION	New Jersey Large Energy Consumers Retail Energy Supply Association	BPU EM05020106 OAL PUC-1874-05	Direct	NJ	Merger	11/14/2005
50102	PUBLIC UTILITY COMMISSION OF TEXAS	Texas Industrial Energy Consumers	31540	Direct	TX	Nodal Market Protocols	11/10/2005
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31315	Cross-Rebuttal	TX	Recovery of Purchased Power Capacity Costs	10/4/2005
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31315	Direct	TX	Recovery of Purchased Power Capacity Costs	9/22/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	EL05-19-002; ER05-168-001	Responsive	FERC	Fuel Cost Adjustment Clause (FCAC)	9/19/2005
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	31056	Direct	TX	Stranded Costs and Other True-Up Balances	9/2/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	EL05-19-00; ER05-168-00	Direct	FERC	Fuel Cost adjustment clause (FCAC)	8/19/2006
50203	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	19142-U	Direct	GA	Fuel Cost Recovery	4/8/2005
41230	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	30706	Direct	TX	Competition Transition Charge	3/16/2005
41230	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	30485	Supplemental Direct	TX	Financing Order	1/14/2005
41230	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	30485	Direct	TX	Financing Order	1/7/2005
8201	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	04S-164E	Cross Answer	CO	Cost of Service Study, Interruptible Rate Design	12/13/2004
8201	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	04S-164E	Answer	CO	Cost of Service Study, Interruptible Rate Design	10/12/2004

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8244	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	18300-U	Direct	GA	Revenue Requirements, Revenue Allocation, Cost of Service, Rate Design, Economic Development	10/8/2004
8195	CENTERPOINT, RELIANT AND TEXAS GENCO	Texas Industrial Energy Consumers	29526	Direct	TX	True-Up	6/1/2004
8156	GEORGIA POWER COMPANY/SAVANNAH ELECTRIC AND POWER COMPANY	Georgia Industrial Group	17687-U/17688-U	Direct	GA	Demand Side Management	5/14/2004
8148	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	29206	Direct	TX	True-Up	3/29/2004
8095	CONECTIV POWER DELIVERY	New Jersey Large Energy Consumers	ER03020110	Surrebuttal	NJ	Cost of Service	3/18/2004
8111	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	28840	Rebuttal	TX	Cost Allocation and Rate Design	2/4/2004
8095	CONECTIV POWER DELIVERY	New Jersey Large Energy Consumers	ER03020110	Direct	NJ	Cost Allocation and Rate Design	1/4/2004
7850	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	26195	Supplemental Direct	TX	Fuel Reconciliation	9/23/2003
8045	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE-2003-00285	Direct	VA	Stranded Cost	9/5/2003
8022	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	17066-U	Direct	GA	Fuel Cost Recovery	7/22/2003
8002	AEP TEXAS CENTRAL COMPANY	Flint Hills Resources, LP	25395	Direct	TX	Delivery Service Tariff Issues	5/9/2003
7857	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	ER02050303	Supplemental	NJ	Cost of Service	3/14/2003
7850	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	26195	Direct	TX	Fuel Reconciliation	12/31/2002
7857	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	ER02050303	Surrebuttal	NJ	Revenue Allocation	12/16/2002
7836	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	02S-315EG	Answer	CO	Incentive Cost Adjustment	11/22/2002
7857	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	ER02050303	Direct	NJ	Revenue Allocation	10/22/2002
7863	DOMINION VIRGINIA POWER	Virginia Committee for Fair Utility Rates	PUE-2001-00306	Direct	VA	Generation Market Prices	8/12/2002
7718	FLORIDA POWER CORPORATION	Florida Industrial Power Users Group	000824-EI	Direct	FL	Rate Design	1/18/2002
7633	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	14000-U	Direct	GA	Cost of Service Study, Revenue Allocation, Rate Design	10/12/2001
7555	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	010001-EI	Direct	FL	Rate Design	10/12/2001
7658	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	24468	Direct	TX	Delay of Retail Competition	9/24/2001
7647	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	24469	Direct	TX	Delay of Retail Competition	9/22/2001
7608	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	23950	Direct	TX	Price to Beat	7/3/2001
7593	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	13711-U	Direct	GA	Fuel Cost Recovery	5/11/2001
7520	GEORGIA POWER COMPANY SAVANNAH ELECTRIC & POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	12499-U,13305-U, 13306-U	Direct	GA	Integrated Resource Planning	5/11/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Rebuttal	TX	Allocation/Collection of Municipal Franchise Fees	3/31/2001
7309	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	22351	Cross-Rebuttal	TX	Energy Efficiency Costs	2/22/2001
7305	CPL, SWEPCO, and WTU	Texas Industrial Energy Consumers	22352, 22353, 22354	Cross-Rebuttal	TX	Allocation/Collection of Municipal Franchise Fees	2/20/2001
7423	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	13140-U	Direct	GA	Interruptible Rate Design	2/16/2001
7305	CPL, SWEPCO, and WTU	Texas Industrial Energy Consumers	22352, 22353, 22354	Supplemental Direct	TX	Transmission Cost Recovery Factor	2/13/2001

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7310	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	22349	Cross-Rebuttal	TX	Rate Design	2/12/2001
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Cross-Rebuttal	TX	Unbundled Cost of Service	2/12/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Cross-Rebuttal	TX	Stranded Cost Allocation	2/6/2001
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Direct	TX	Rate Design	2/5/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Supplemental Direct	TX	Rate Design	1/25/2001
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Cross-Rebuttal	TX	Stranded Cost Allocation	1/12/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Direct	TX	Stranded Cost Allocation	1/9/2001
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Direct	TX	Cost Allocation	12/13/2000
7375	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	22352	Cross-Rebuttal	TX	CTC Rate Design	12/1/2000
7375	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	22352	Direct	TX	Cost Allocation	11/1/2000
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Direct	TX	Cost Allocation	11/1/2000
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Cross-Rebuttal	TX	Cost Allocation	11/1/2000
7305	CPL, SWEPCO, and WTU	Texas Industrial Energy Consumers	22352, 22353, 22354	Direct	TX	Excess Cost Over Market	11/1/2000
7315	VARIOUS UTILITIES	Texas Industrial Energy Consumers	22344	Direct	TX	Generic Customer Classes	10/14/2000
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Direct	TX	Excess Cost Over Market	10/10/2000
7315	VARIOUS UTILITIES	Texas Industrial Energy Consumers	22344	Rebuttal	TX	Excess Cost Over Market	10/1/2000
7310	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	22349	Cross-Rebuttal	TX	Generic Customer Classes	10/1/2000
7310	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	22349	Direct	TX	Excess Cost Over Market	9/27/2000
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Cross-Rebuttal	TX	Excess Cost Over Market	9/26/2000
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Direct	TX	Excess Cost Over Market	9/19/2000
7334	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	11708-U	Rebuttal	GA	RTP Petition	3/24/2000
7334	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	11708-U	Direct	GA	RTP Petition	3/1/2000
7232	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Industrial Energy Consumers	99A-377EG	Answer	CO	Merger	12/1/1999
7258	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	21527	Direct	TX	Securitization	11/24/1999
7246	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	21528	Direct	TX	Securitization	11/24/1999
7089	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE980813	Direct	VA	Unbundled Rates	7/1/1999
7090	AMERICAN ELECTRIC POWER SERVICE CORPORATION	Old Dominion Committee for Fair Utility Rates	PUE980814	Direct	VA	Unbundled Rates	5/21/1999
7142	SHARYLAND UTILITIES, L.P.	Sharyland Utilities	20292	Rebuttal	TX	Certificate of Convenience and Necessity	4/30/1999
7060	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Industrial Energy Consumers Group	98A-511E	Direct	CO	Allocation of Pollution Control Costs	3/1/1999
7039	SAVANNAH ELECTRIC AND POWER COMPANY	Various Industrial Customers	10205-U	Direct	GA	Fuel Costs	1/1/1999
6945	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	950379-EI	Direct	FL	Revenue Requirement	10/1/1998
6873	GEORGIA POWER COMPANY	Georgia Industrial Group	9355-U	Direct	GA	Revenue Requirement	10/1/1998
6729	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE960036,PUE960296	Direct	VA	Alternative Regulatory Plan	8/1/1998

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6713	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	16995	Cross-Rebuttal	TX	IRR	1/1/1998
6582	HOUSTON LIGHTING & POWER COMPANY	Lyondell Petrochemical Company	96-02867	Direct	COURT	Interruptible Power	1997
6758	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	17460	Direct	TX	Fuel Reconciliation	12/1/1997
6729	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE960036,PUE960296	Direct	VA	Alternative Regulatory Plan	12/1/1997
6713	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	16995	Direct	TX	Rate Design	12/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	16705	Rebuttal	TX	Competitive Issues	10/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	16705	Rebuttal	TX	Competition	10/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	473-96-2285/16705	Direct	TX	Rate Design	9/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	16705	Direct	TX	Wholesale Sales	8/1/1997
6744	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	970171-EU	Direct	FL	Interruptible Rate Design	5/1/1997
6632	MISSISSIPPI POWER COMPANY	Colonial Pipeline Company	96-UN-390	Direct	MS	Interruptible Rates	2/1/1997
6558	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	15560	Direct	TX	Competition	11/11/1996
6508	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	15195	Direct	TX	Treatment of margins	9/1/1996
6475	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	15015	DIRECT	TX	Real Time Pricing Rates	8/8/1996
6449	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	14965	Direct	TX	Quantification	7/1/1996
6449	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	14965	Direct	TX	Interruptible Rates	5/1/1996
6449	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	14965	Rebuttal	TX	Interruptible Rates	5/1/1996
6523	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	95A-531EG	Answer	CO	Merger	4/1/1996
6235	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	13575	Direct	TX	Competitive Issues	4/1/1996
6435	SOUTHWESTERN PUBLIC SERVICE COMMISSION	Texas Industrial Energy Consumers	14499	Direct	TX	Acquisition	11/1/1995
6391	HOUSTON LIGHTING & POWER COMPANY	Grace, W.R. & Company	13988	Rebuttal	TX	Rate Design	8/1/1995
6353	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	14174	Direct	TX	Costing of Off-System Sales	8/1/1995
6157	WEST TEXAS UTILITIES COMPANY	Texas Industrial Energy Consumers	13369	Rebuttal	TX	Cancellation Term	8/1/1995
6391	HOUSTON LIGHTING & POWER COMPANY	Grace, W.R. & Company	13988	Direct	TX	Rate Design	7/1/1995
6157	WEST TEXAS UTILITIES COMPANY	Texas Industrial Energy Consumers	13369	Direct	TX	Cancellation Term	7/1/1995
6296	GEORGIA POWER COMPANY	Georgia Industrial Group	5601-U	Rebuttal	GA	EPACT Rate-Making Standards	5/1/1995
6296	GEORGIA POWER COMPANY	Georgia Industrial Group	5601-U	Direct	GA	EPACT Rate-Making Standards	5/1/1995
6278	COMMONWEALTH OF VIRGINIA	VCFUR/ODCFUR	PUE940067	Rebuttal	VA	Integrated Resource Planning	5/1/1995
6295	GEORGIA POWER COMPANY	Georgia Industrial Group	5600-U	Supplemental	GA	Cost of Service	4/1/1995
6063	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	94I-430EG	Rebuttal	CO	Cost of Service	4/1/1995
6063	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	94I-430EG	Reply	CO	DSM Rider	4/1/1995
6295	GEORGIA POWER COMPANY	Georgia Industrial Group	5600-U	Direct	GA	Interruptible Rate Design	3/1/1995
6278	COMMONWEALTH OF VIRGINIA	VCFUR/ODCFUR	PUE940067	Direct	VA	EPACT Rate-Making Standards	3/1/1995
6125	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	13456	Direct	TX	DSM Rider	3/1/1995
6235	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	13575|13749	Direct	TX	Cost of Service	2/1/1995

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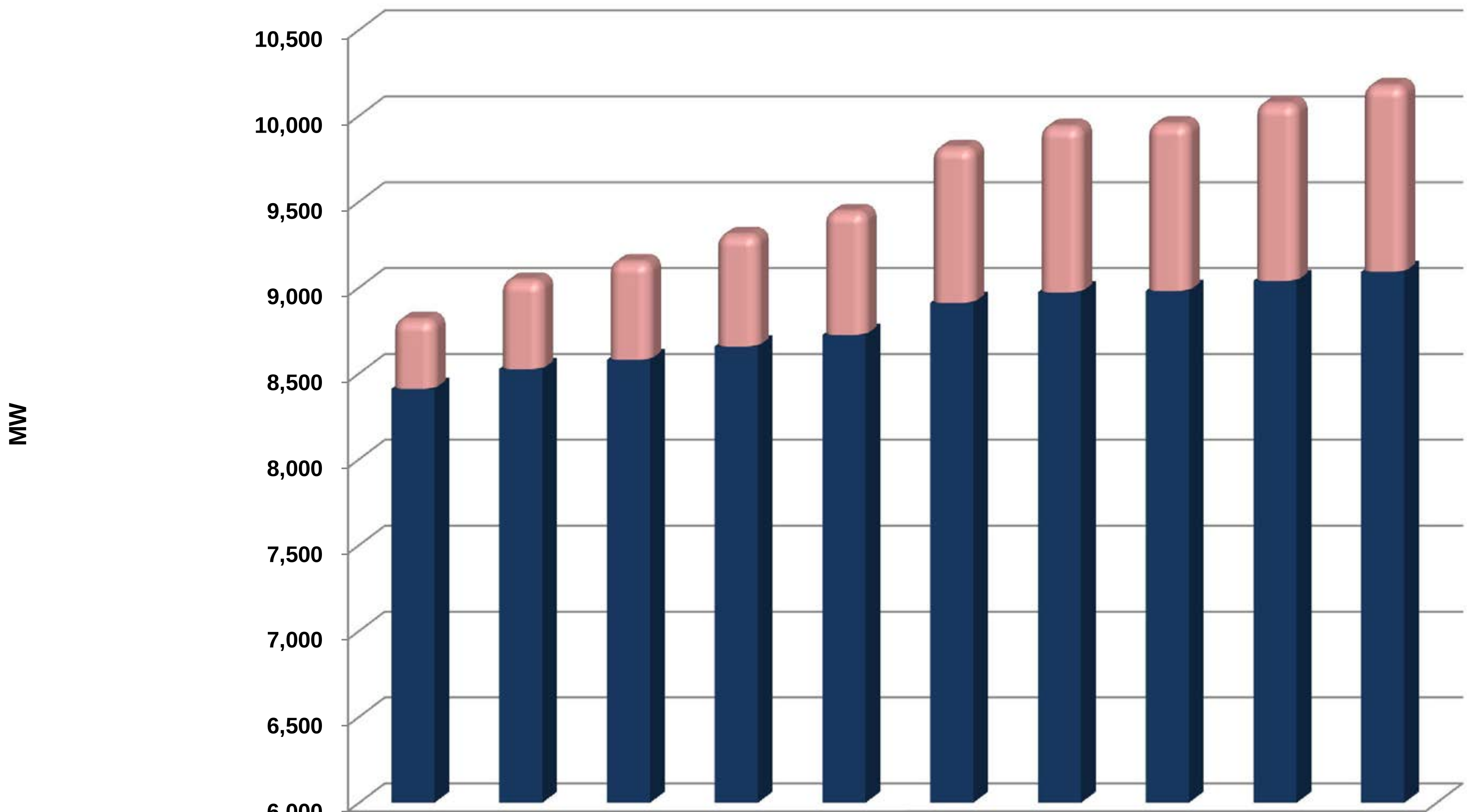
6063	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	94I-430EG	Answering	CO	Competition	2/1/1995
6061	HOUSTON LIGHTING & POWER COMPANY	Texas Industrial Energy Consumers	12065	Direct	TX	Rate Design	1/1/1995
6181	GULF STATES UTILITIES COMPANY	Texas Industrial Energy Consumers	12852	Direct	TX	Competitive Alignment Proposal	11/1/1994
6061	HOUSTON LIGHTING & POWER COMPANY	Texas Industrial Energy Consumers	12065	Direct	TX	Rate Design	11/1/1994
5929	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	12820	Direct	TX	Rate Design	10/1/1994
6107	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	12855	Direct	TX	Fuel Reconciliation	8/1/1994
6112	HOUSTON LIGHTING & POWER COMPANY	Texas Industrial Energy Consumers	12957	Direct	TX	Standby Rates	7/1/1994
5698	GULF POWER COMPANY	Misc. Group	931044-EI	Direct	FL	Standby Rates	7/1/1994
5698	GULF POWER COMPANY	Misc. Group	931044-EI	Rebuttal	FL	Competition	7/1/1994
6043	EL PASO ELECTRIC COMPANY	Phelps Dodge Corporation	12700	Direct	TX	Revenue Requirement	6/1/1994
6082	GEORGIA PUBLIC SERVICE COMMISSION	Georgia Industrial Group	4822-U	Direct	GA	Avoided Costs	5/1/1994
6075	GEORGIA POWER COMPANY	Georgia Industrial Group	4895-U	Direct	GA	FPC Certification Filing	4/1/1994
6025	MISSISSIPPI POWER & LIGHT COMPANY	MIEG	93-UA-0301	Comments	MS	Environmental Cost Recovery Clause	1/21/1994
5971	FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	940042-EI	Direct	FL	Section 712 Standards of 1992 EPACT	1/1/1994

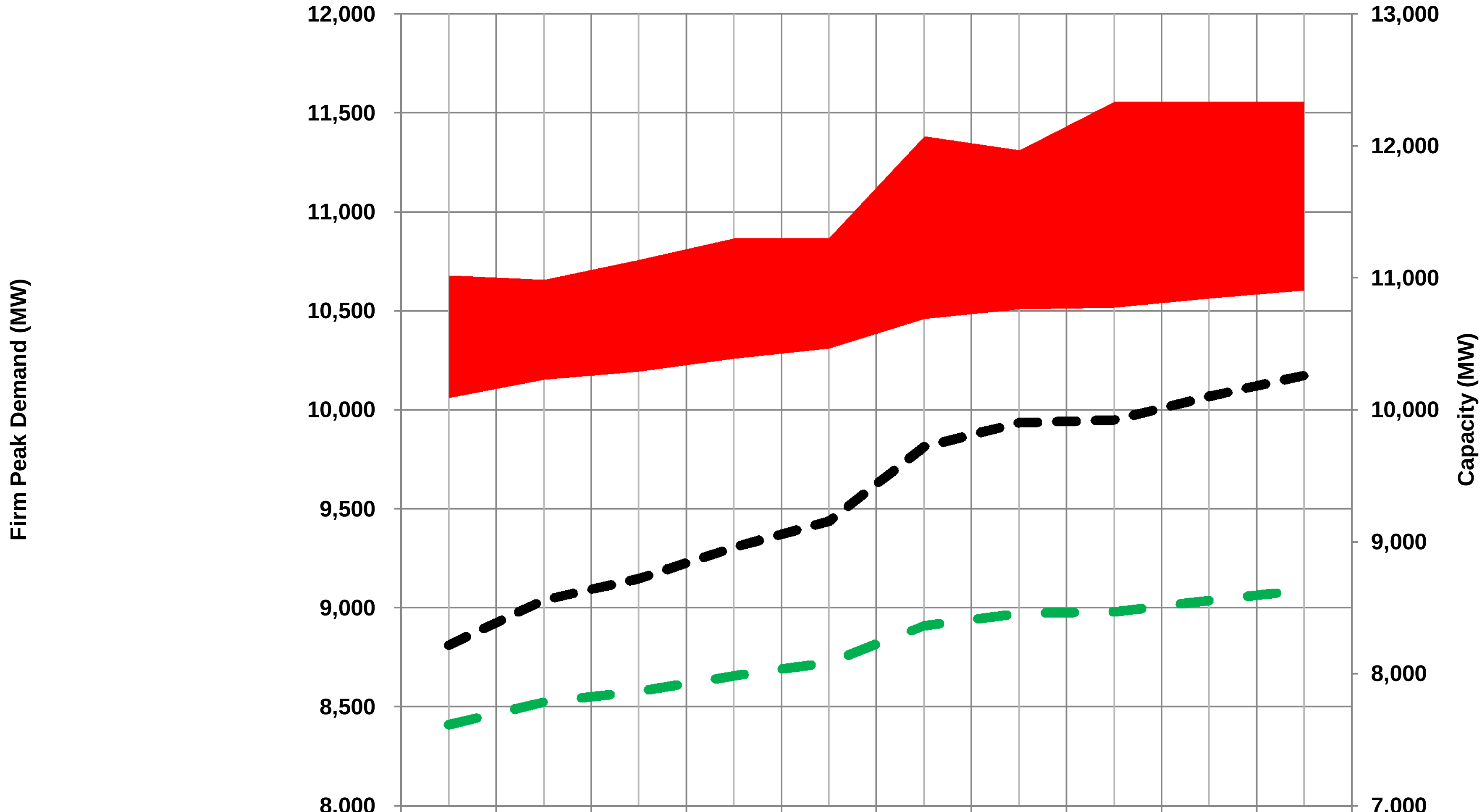
DUKE ENERGY FLORIDA
Projected Net Firm Summer Peak Demand
Projected 2014-2023



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
DEF Additional Load Growth	402	516	570	649	716	902	964	971	1,030	1,083
At 50% of Projected Growth	8,411	8,525	8,579	8,658	8,725	8,911	8,973	8,980	9,039	9,092

Source: Duke Energy Florida 2014 Ten Year Site Plan

Projected Summer Capacity and Firm Peak Demand
DEF Vs. Load Growth at 50% of DEF's Projection



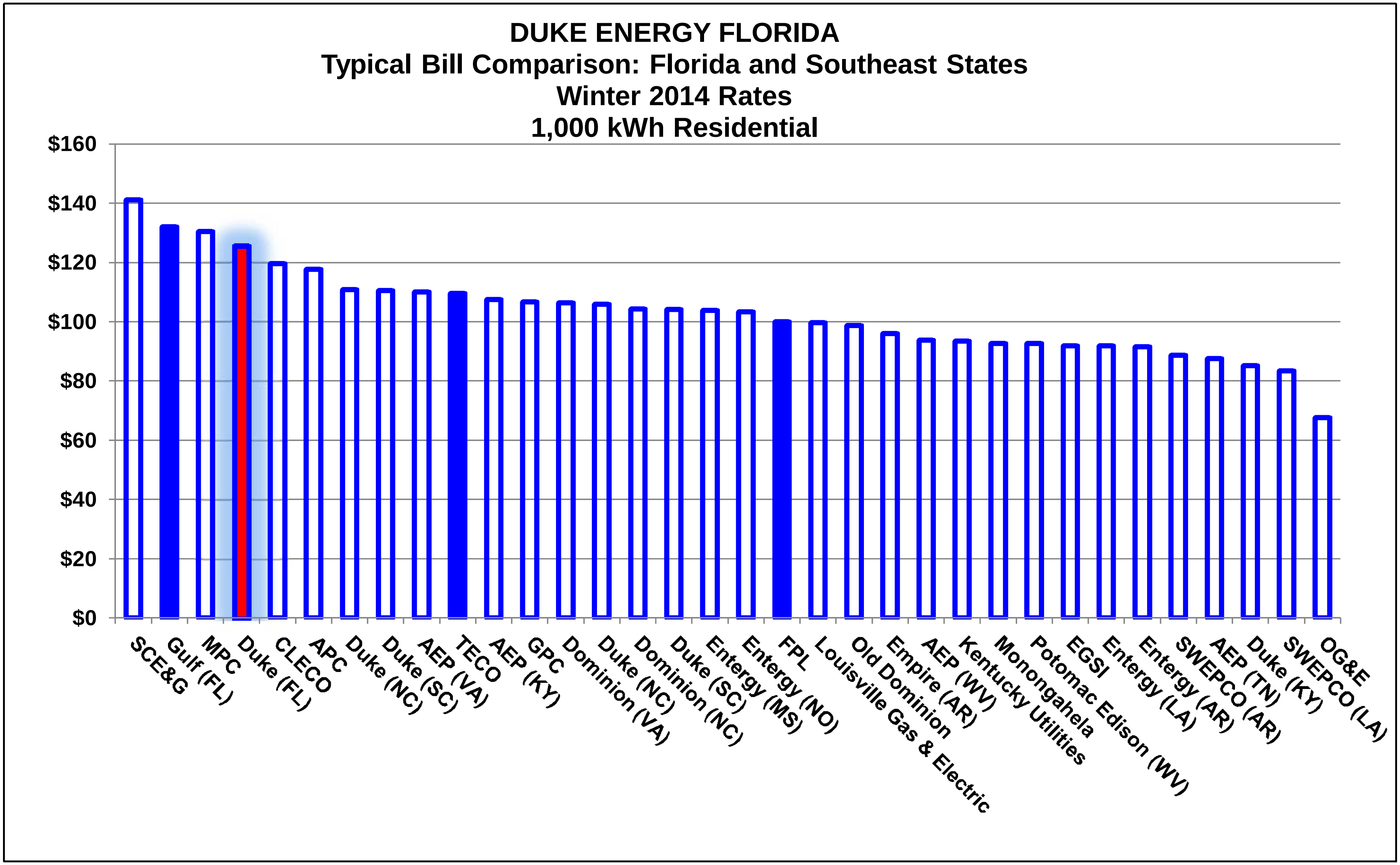
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Potential Excess Capacity	930	760	844	915	837	1,383	1,204	1,563	1,493	1,429
At 50% of Projected Growth	10,093	10,230	10,295	10,389	10,469	10,693	10,767	10,776	10,846	10,910
DEF Proj. Firm Peak Demand	8,812	9,041	9,149	9,306	9,440	9,813	9,936	9,951	10,068	10,174
At 50% of Projected Growth	8,411	8,525	8,579	8,658	8,725	8,911	8,973	8,980	9,039	9,092

DUKE ENERGY FLORIDA
Scheduled Rate Increases Associated With Future Capital Recovery
Pursuant To The 2013 Settlement
(Dollar Amounts in Millions)

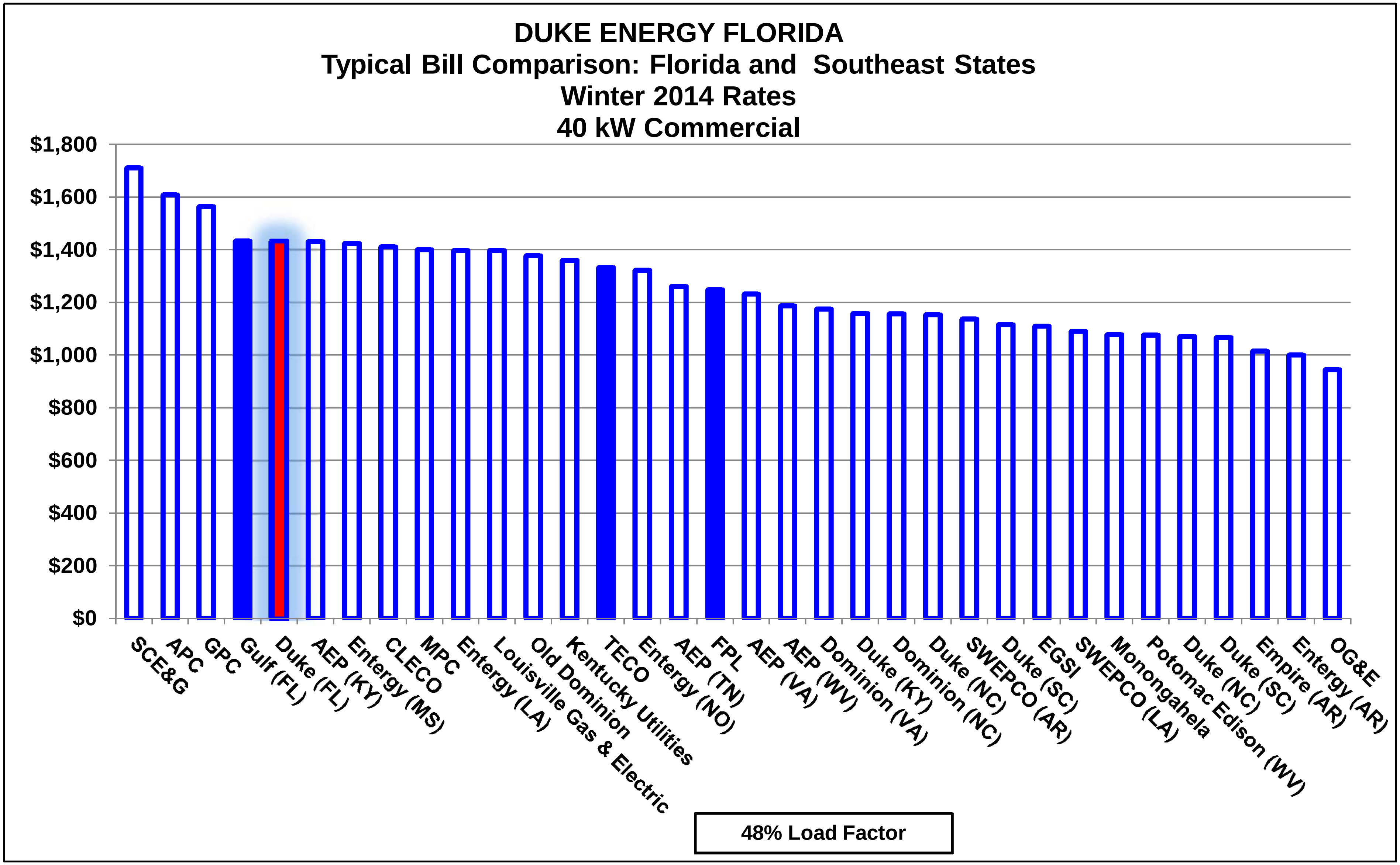
Line	Description	Effective Date	Capital Recovery	Pargraph in D.130208 Settlement	Notes	Source of Cost Data
		(1)	(2)	(3)	(4)	(5)
	Existing Generation Facilities					
1	Point of Discharge Cooling Towers	Jan-13	$18.2	9b	3-Year Amortization	d.
2	Base Rate Increase	Jan-13		13	$150 Million per Year	b.
3	Levy EPC Contract Cancelation	2013-2017	$350.0	11	5-Year Amortization	b.
4	Crystal River 3 EPU	2013-2019	$323.0	9a	7-Year Amortization	a.
5	Fuel Factor Increases	Jan-14		7	$1.00 /MWh: 2014-2015 $1.50 /MWh: 2016	b.
6	Crystal River 3 Regulatory Asset (RA)	Jan-17	$1,466.0	5e2	Capped Amount; 20-Year Recovery	b.
7	Crystal River 3 Dry Cask Storage	Jan-17	TBD	5e1	Recovery Commences After CR3 RA	
8	CR3 Nuclear Decommissioning Trust	As Needed		7b	Up to $8 Million/Year	
9	Crystal River South	Jan-21	TBD	8	Remaining Book Value	
10	Total		$2,157.2			
	New Generation Facilities					
11	Suwannee Simple Cycle Project	Jun-16	$197.0	16a	Limited Proceeding; 35-Years	c.
12	Hines Chiller Uprate Project	Mar-17	$160.0	16a	Limited Proceeding; 29 Years	c.
13	Citrus County Combined Cycle	May-18	$1,514.0	16b	GBRA	c.
14	Total		$1,871.0			
15	**Total Future Capital Recovery**		**$4,028.2**			

Sources:

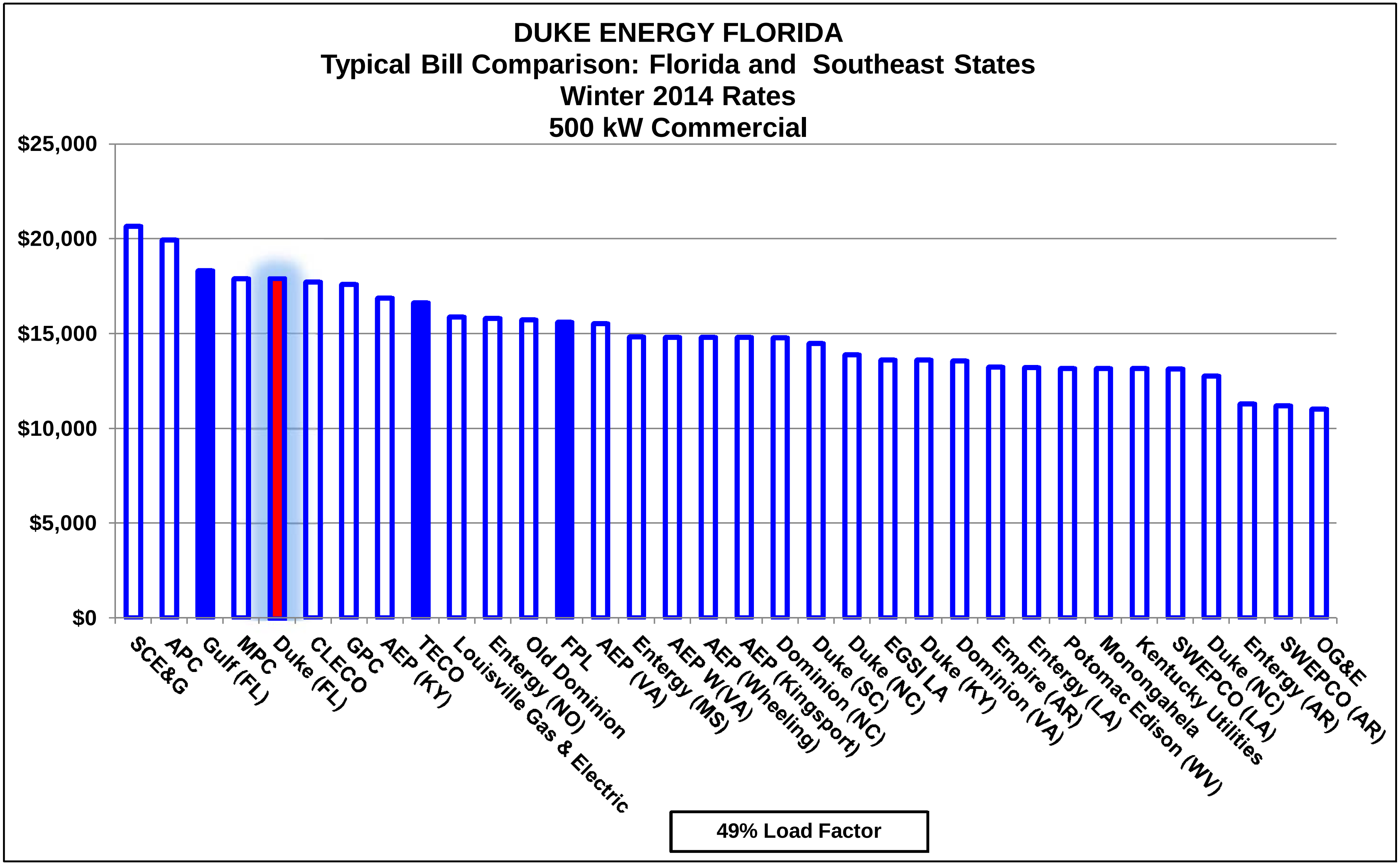
a 2013 FERC Form 1 Report.
b Settlement in Docket No. 130208.
c DEF Petitions in Docket Nos. 140010 and 140011.
d. Direct Testimony of Thomas G. Foster, Docket No. 130007-EI



Source: Edison Electric Institute - TYPICAL BILLS AND AVERAGE RATES REPORT - Winter 2014



Source: Edison Electric Institute - TYPICAL BILLS AND AVERAGE RATES REPORT - Winter 2014



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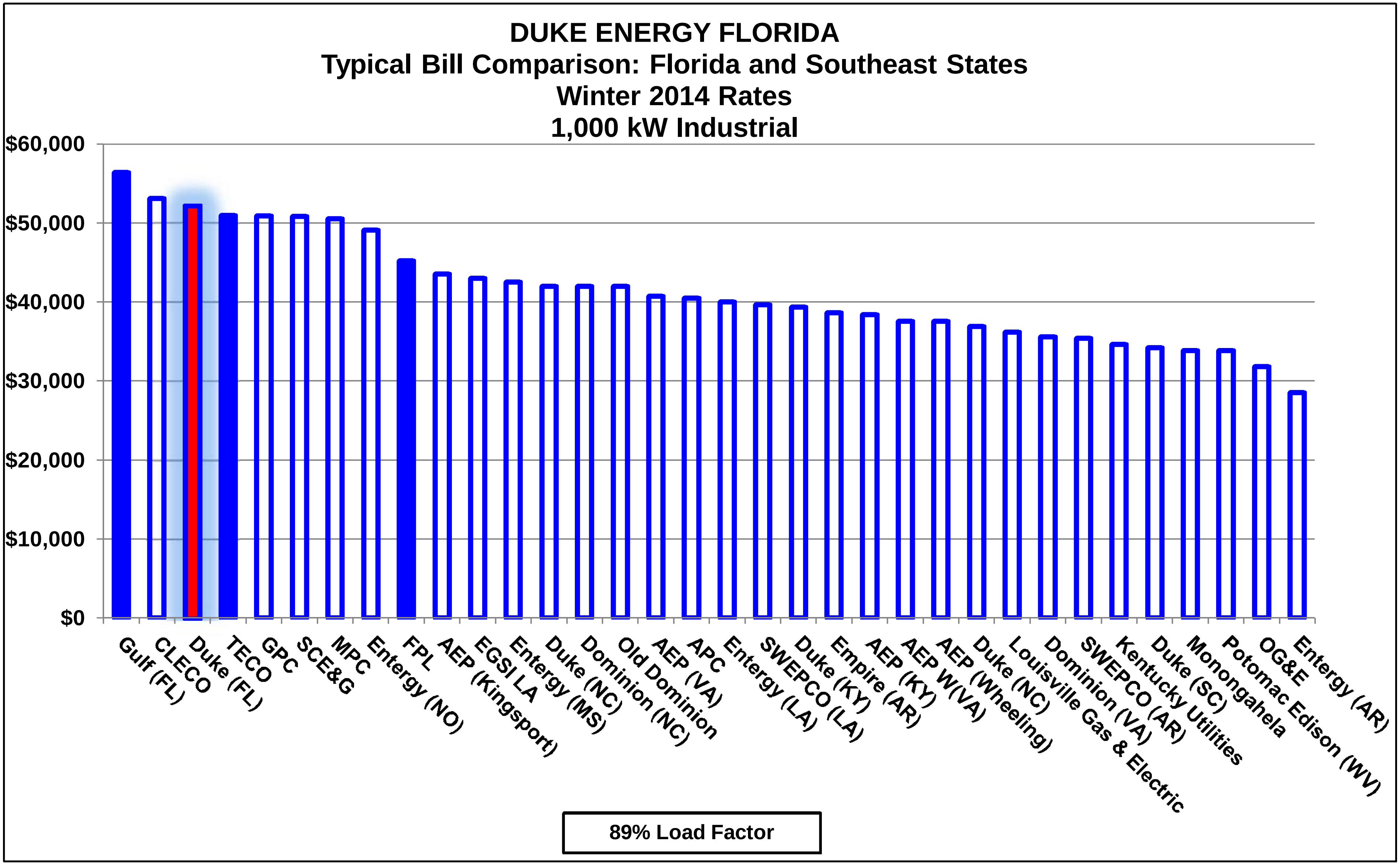

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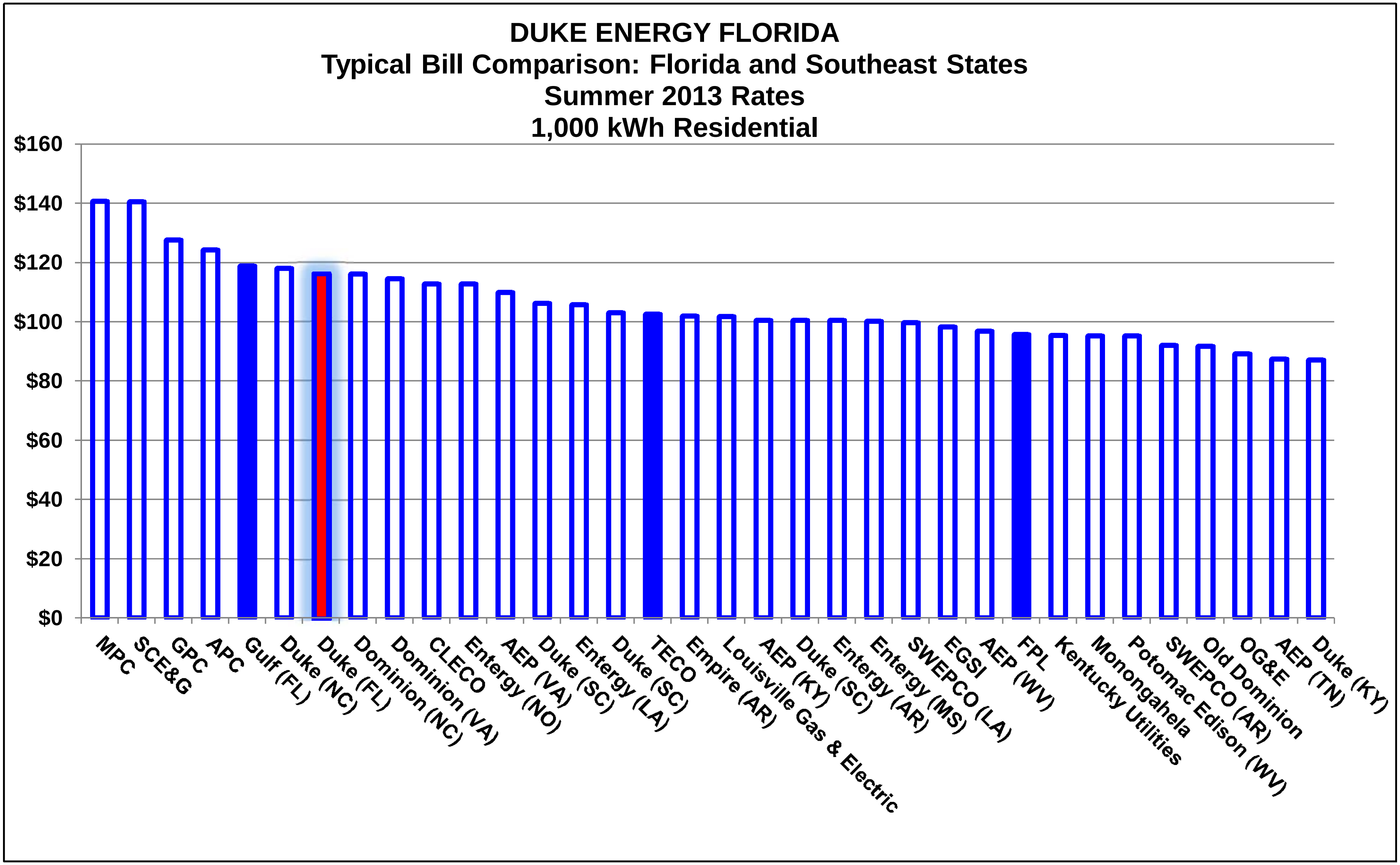

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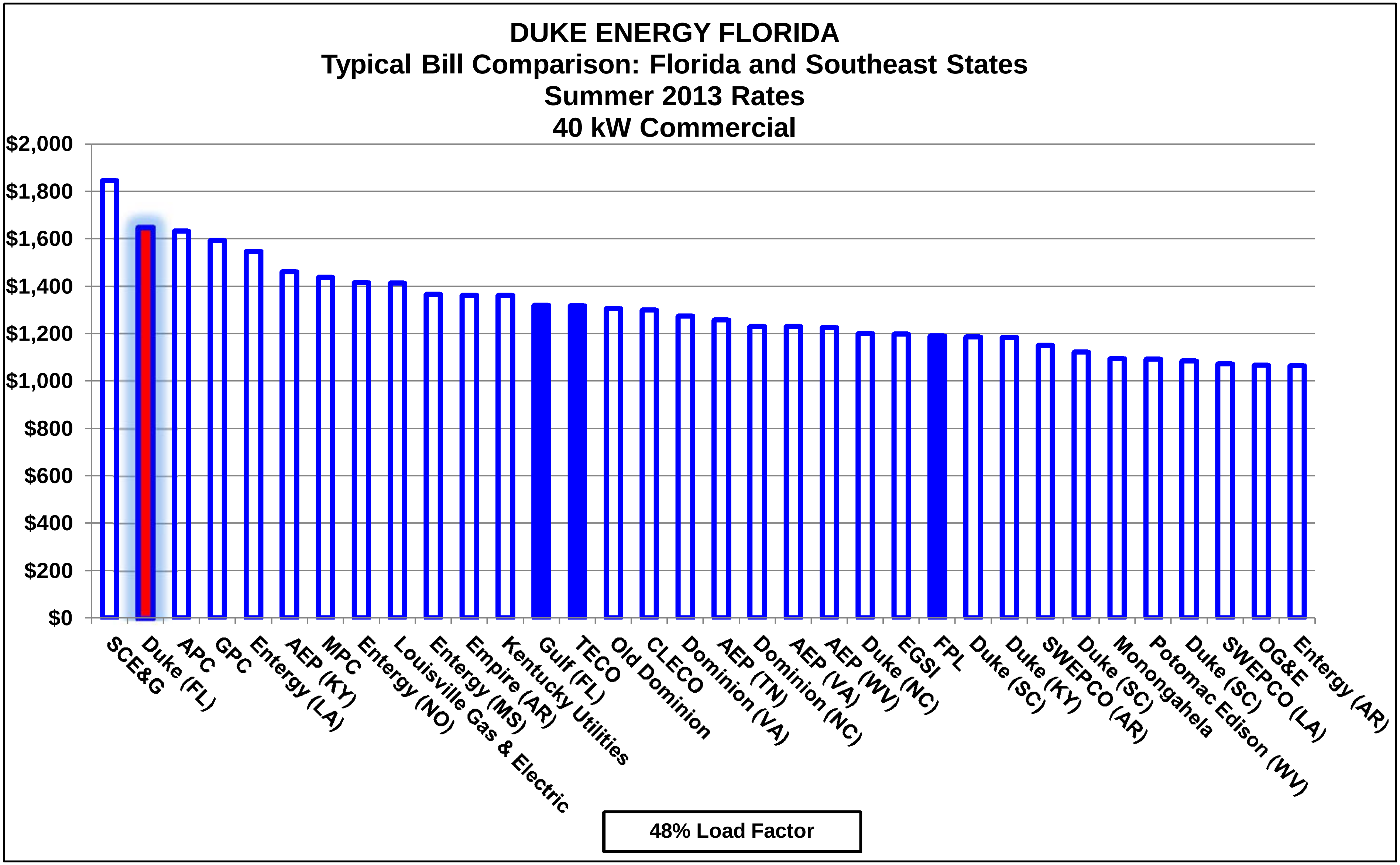

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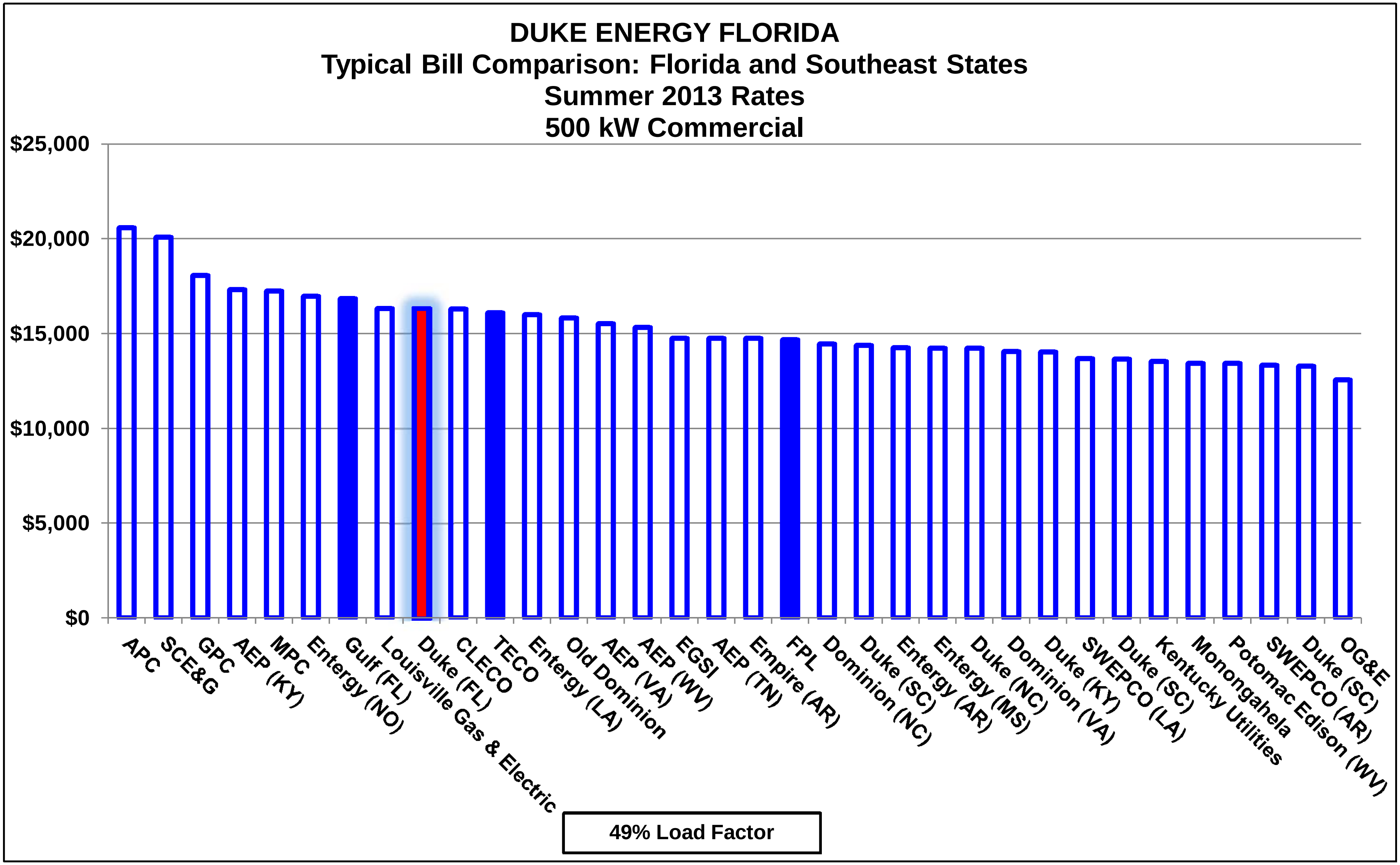

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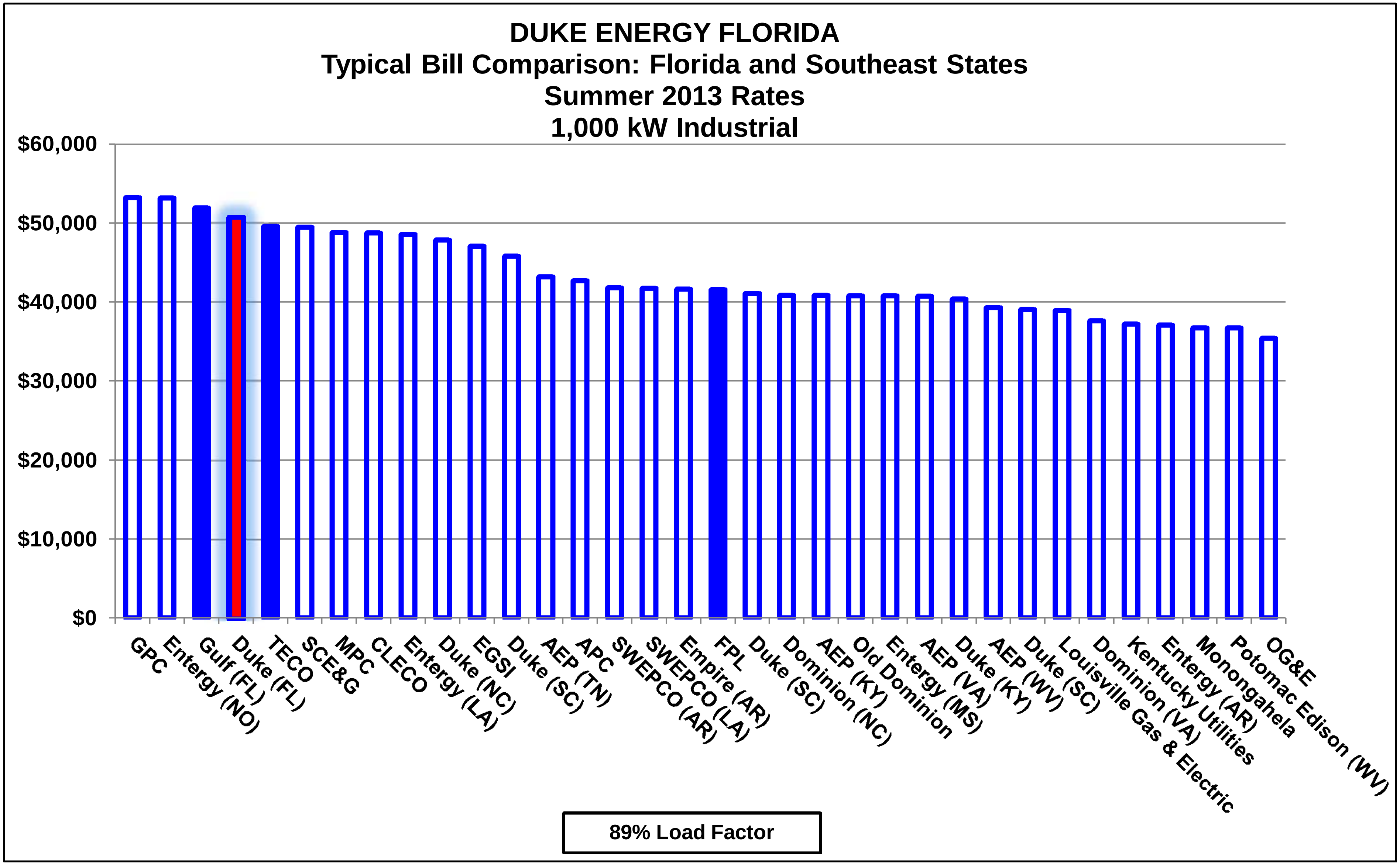

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