COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	))))	**CASE NO. 2016-00371**

REDACTED – PUBLIC VERSION

Direct Testimony and Exhibits

of

JEFFRY POLLOCK

On Behalf of

Louisville/Jefferson Metro Government

March 3, 2017

J. POLLOCK
INCORPORATED

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GLOSSARY OF ACRONYMS

Term	Definition
AMS	Advanced Metering System
BIP	Base-Intermediate-Peak
CCOSS	Class Cost-of-Service Study
CP	Coincident Peak
DSM	Demand Side Management
ECR	Environmental Cost Recovery
FERC	Federal Energy Regulatory Commission
FPL	Florida Power & Light Company
FPSC	Florida Public Service Commission
GPC	Georgia Power Company
GPSC	Georgia Public Service Commission
KLC	Kentucky League of Cities
LG&E	Kentucky Utilities Company
kW	Kilowatt
kWh	Kilowatt-Hour
LG&E	Louisville Gas and Electric Company
LOLP	Loss of Load Probability
Louisville Metro	Louisville/Jefferson Metro Government
NSP	Northern States Power Company
O&M	Operation and Maintenance
PEF	Progress Energy Florida
TIA	Team Incentive Award
USOA	Uniform System of Accounts

Direct Testimony of Jeffry Pollock

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

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 Master's Degree in Business Administration from Washington University. Since graduation in 1975, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces. My qualifications are documented in **Appendix A.** I have offered testimony in 25 state regulatory Commissions, FERC and several municipal/governmental utility boards, legislative committees and courts. A partial list of my appearances is provided in **Appendix B** to this testimony. This is my first appearance in Kentucky.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Louisville/Jefferson Metro Government (Louisville Metro). Louisville Metro is located in the largest, most densely populated area within the service area of Louisville Gas and Electric Company (LG&E). Furthermore, Louisville Metro provides and pays for the most extensive street light and traffic light infrastructure of any city within LG&E's service territory, and it also purchases electricity and natural gas delivery services under a wide range of tariffs.

Q WHAT ISSUES ARE YOU ADDRESSING?

A I am addressing the following issues:

- LG&E's proposed revenue requirement (Part 2);
- Electric class cost-of-service study (Part 3);
- Electric class revenue allocation (Part 4);
- Gas class cost-of-service study (Part 5); and
- Gas class revenue allocation (Part 6).

Q ARE YOU SPONSORING ANY EXHIBITS TO YOUR DIRECT TESTIMONY?

A Yes. I am sponsoring **Exhibit JP-1** through **JP-16**. These exhibits were prepared by me or under my supervision and direction.

Q DO YOU ENDORSE LG&E'S PROPOSALS ON THOSE ISSUES NOT ADDRESSED IN YOUR DIRECT TESTIMONY?

A No. The fact that I am not addressing all revenue requirement, CCOSS, revenue allocation issues and my use of LG&E's proposed revenue requirement in Parts 3-6 of my testimony should not be interpreted as an endorsement of LG&E's proposals.

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations are as follows:

Revenue Requirement Issues

- LG&E is proposing to increase depreciation rates. This proposal would increase test-year revenue deficiency by $14.3 million Electric and $0.5 million Gas. These increases ignore the results of LG&E's depreciation study, which reveals that it has accumulated a surplus in its depreciation reserve of $112.2 million (Electric) and $28.1 million (Gas).

- Depreciation is the ratable recovery of investment over the useful life of an asset. Accordingly, a depreciation surplus means that LG&E has not recovered its investments ratably. Consequently, the current generation of customers is subsidizing future customers. In other words, there is intergenerational inequity.

- The Commission should order LG&E to amortize this surplus over a five year period. This would lower LG&E's claimed revenue deficiency by $12.9 million (Electric) and $4.2 million (Gas). Amortizing a depreciation surplus is consistent with accepted practice and recent decisions made by other state regulators. Amortizing the surplus, thus, would not only mitigate the proposed rate increases, it would restore intergenerational equity.

- LG&E has overstated its test-year incentive compensation expense by $[redacted] million because it assumed it would payout 49% more for achieving non-financial goals than in the base year. A 49% increase is many times higher than the projected increase in wages and salaries. Overstating this expense by $[redacted] million would effectively restore funding for incentive compensation to be paid out for achieving financial goals, despite LG&E's claims to the contrary.

- This Commission and state regulators in many nearby states have consistently disallowed recovery of incentive compensation for achieving financial goals because increasing earnings benefits utility shareholders and not utility customers.

- Accordingly, the Commission should disallow $[redacted] million of test-year incentive compensation expense ($[redacted] million Electric and $[redacted] million Gas).

- LG&E is proposing to include fuel expense in applying the 45-day rule in determining its cash working capital requirement. However, the Fuel Adjustment Clause provides current recovery of fuel costs, and further, LG&E already includes fuel inventory in working capital. Accordingly, fuel expense should be removed from the cash working capital requirement. This would reduce LG&E's Electric revenue deficiency by $4.1 million.

- LG&E is proposing to recover the substantial costs of deploying advanced meters throughout its service area (for both Electric and Gas operations) in base rates, but it is not proposing any mechanism for flowing through the claimed benefits of AMS deployment until after this rate case. This means that until the next rate case, all of the benefits of AMS deployment will flow solely to LG&E shareholders.

- To ensure that customers receive the benefits from the investments that LG&E believes are cost-effective while the new rates are in effect and to incentivize LG&E to maximize the benefits, the Commission should reduce LG&E's claimed revenue deficiency by $13.2 million (Electric) and $2.75 million (Gas), which reflects the estimated benefits for the years 2019 and 2020.

Electric Class Cost-of-Service Study

- LG&E's Electric class cost-of-service studies (CCOSSs) generally comport with accepted practice in that they recognize the ways that costs are incurred to provide electricity service to each of the various customer classes and they account for the differences in class service and load characteristics that support charging different average rates per kilowatt-hour (kWh).
- LG&E is supporting the Loss of Load Probability (LOLP) method of allocating production plant and related operating expenses. LOLP is a variant of the coincident peak (CP) method.
- Despite supporting LOLP, LG&E also filed a cost study using the Base-Intermediate-Peak (BIP) method. This method has previously been accepted by the Commission. The primary differences between LOLP and BIP are that the latter explicitly allocates fixed costs on an energy (or average demand) basis, and it places more weight on winter coincident peak demands than LOLP.
- The results of the LOLP and BIP CCOSSs are directionally similar; that is, the same customer classes are either consistently above cost or consistently below cost at present rates.
- Of the two competing methods, LOLP better reflects cost causation because it is consistent with how LG&E plans its generation system to meet expected customer needs and further, it also recognizes that generation capacity must be sized to meet its projected peak (not average) demand while providing an ample reserve margin in order to keep the lights on and the machines running.
- The LOLP CCOSS results demonstrate that most of the non-Residential classes are paying rates that are above allocated costs; that is, they are subsidizing other classes. The only exceptions are the Retail Transmission Service (RTS) and Special Contract classes, which are being subsidized.

Electric Class Revenue Allocation

- All rates should be moved toward cost; that is, the interclass subsidies should be reduced to the maximum extent practicable. Cost-based rates are equitable and will promote stability. They send proper price signals and therefore encourage conservation and maximize efficiency.
- Moving rates closer to cost should be constrained primarily by the principle of gradualism; that is, no class should experience an increase greater than 1.5 times the system average increase.
- Despite its support for cost-based rates, LG&E's proposed class revenue allocation would not eliminate subsidies gradually. In fact, it would move the majority of customer classes away from (rather than closer to) cost. Further, the RTS class would move from slightly below cost to substantially above cost. Overall, rates would move 47% away from cost. At this pace, rates would never reach cost.
- The Commission should allocate the authorized electric base revenue increase in a manner that would reduce the subsidies, while limiting the maximum increase to 1.5 times the system average base rate increase, excluding embedded fuel costs, to recognize gradualism. Following this process would result in overall rates that are 20% closer to cost.

Class Cost-of-Service Study: Natural Gas

- LG&E's Gas CCOSS generally comports with accepted cost allocation practices. In particular, it properly classifies and allocates the costs of distribution mains and other facilities in a manner consistent with cost causation.
- The CCOSS demonstrates that the non-Residential customer classes are providing rates of return that are substantially above the system average. Thus, these classes are heavily subsidizing Residential gas delivery service.

Class Revenue Allocation: Natural Gas

- The same ratemaking principles apply to the allocation of any increase in gas delivery rates as apply to the allocation of any electric base revenue increase.
- LG&E's proposed allocation would move rates only 5% closer to cost. At this slow pace, it would take 40 years to achieve cost-based rates.
- The Commission should move all gas delivery rates closer to cost. Because the non-Residential classes are heavily subsidizing Residential gas delivery service, their rates should not be increased. Should the Commission authorize a lower revenue requirement, 50% of the reduction should be used to reduce delivery rates to the non-Residential gas

classes. Following this process would result in delivery rates moving about 74% closer to cost.

2. REVENUE REQUIREMENT ISSUES

Q HAVE YOU REVIEWED LG&E'S PROPOSED ELECTRIC AND GAS REVENUE INCREASES?

A Yes. LG&E is proposing a $93.6 million (8.4%) electric revenue increase and $13.8 million (4.2%) gas revenue increase.[1] These increases are based on a fully forecasted test year: the twelve months ending June 30, 2018. The choice of a fully forecasted test year not only eliminates regulatory lag, thereby reducing operating risk, it also invites scrutiny over the many assumptions essential to setting just and reasonable rates.

For example, LG&E approves its official corporate budget in late November prior to the start of the fiscal year.[2] Thus, although the 2017 portion of the test year has been fully vetted by LG&E's upper management, the 2018 portion of the test year has not. This makes it especially important to thoroughly scrub and, if appropriate, challenge key assumptions particularly when they are noticeably out-of-line relative to past experience.

Q ARE THERE ANY ASPECTS OF LG&E'S PROPOSED REVENUE REQUIREMENT THAT RAISE CONCERNS ABOUT WHETHER THE PROPOSED RATES WOULD BE JUST AND REASONABLE?

A Yes. As discussed next, LG&E is proposing to change its depreciation rates even though it has accumulated a substantial surplus in its accumulated depreciation reserve for certain functionalized plant. If the Commission orders LG&E to amortize

[1] Schedule M-2.3

[2] LG&E's Response to AG 1-112.

this surplus, consistent with recent decisions made by other state regulators, it could significantly mitigate the proposed increases, while restoring intergenerational equity.

Further, test-year revenue requirements reflect unexplained large increases in incentive compensation expense and the substantial costs of deploying an Advanced Metering System (AMS), but without recognizing any of the attendant benefits (*i.e.,* cost savings). Because the rates to be approved in this matter could remain in effect for at least two years, adopting these proposals would not reasonably balance LG&E's interests with the interests of LG&E's customers. This would be contrary to the regulatory compact, which should provide LG&E a reasonable opportunity (and not a guarantee) to recover its reasonable and necessary operating expenses and provide a reasonable return on its used and useful investments.

Depreciation Expense

Summary

Q HAVE YOU REVIEWED THE TESTIMONY CONCERNING DEPRECIATION ISSUES AS FILED BY LG&E IN THIS PROCEEDING?

A Yes. LG&E is proposing changes in its depreciation rates. The proposed changes account for about $14.3 million of LG&E's claimed $93.6 million electric revenue deficiency and for about $0.5 million of the claimed $13.8 million gas revenue deficiency.

Q DO YOU AGREE WITH LG&E'S PROPOSED TEST-YEAR DEPRECIATION EXPENSE?

A No. First, LG&E has ignored its own depreciation studies, which demonstrate that LG&E has accumulated surpluses of $112.2 million and $28.1 million in its Electric and Gas depreciation reserves, respectively. The results of LG&E's depreciation study for electric plant are summarized in **Exhibit JP-1**, page 1, and in the table below.

Electric Plant Depreciation Reserve Surplus and Annual Accruals
Excluding ECR-Related Investment
Kentucky Jurisdiction
($ in Millions)

Function	Reserve Surplus	Proposed Accrual	Years of Accruals	Average Remaining Life
Steam Production	$56.8	$57.3	1.0	23.2
Hydro Production	($0.6)	$4.0	0.2	33.5
Other Production	($13.7)	$16.8	0.8	19.0
Transmission	$17.4	$9.6	1.8	45.9
Distribution	$40.5	$37.4	1.1	39.3
General	$0.4	$0.6	0.6	9.6
Common	$11.4	$19.8	0.6	5.6
Total	$112.2	$145.5		

As the table demonstrates, the steam production and distribution functions account for $97.3 million ($56.8 million + $40.5 million) of the $112.2 million surplus (Electric).

The results of LG&E's Gas depreciation study are summarized in **Exhibit JP-1**, page 2, and in the table below.

Gas Plant Reserve Surplus and Annual Accruals Kentucky Jurisdiction ($ in Millions)				
Function	**Reserve Surplus**	**Proposed Depreciation Expense**	**Years of Accruals**	**Average Remaining Life**
Storage	$5.6	$3.6	1.6	39.9
Transmission	$0.4	$1.1	0.4	55.0
Distribution	$16.5	$25.2	0.7	38.5
General	$0.7	$0.5	1.4	12.9
Common	$4.9	$8.5	0.6	5.6
Total	$28.1	$38.9		

As the table demonstrates, the storage, distribution and common functions account for $27 million ($5.6 million + $16.5 million + $4.9 million) of the $28.1 million gas depreciation surplus.

Q SHOULD LG&E'S PROPOSED DEPRECIATION RATES BE APPROVED?

A No. LG&E's proposed deprecation rates do little to reduce the $97.3 million and $27 million of surpluses accumulated in the electric production and distribution plant and natural gas storage, distribution and common plant. Eliminating the surplus would take between 23 and 39 years. As explained later, the presence of a depreciation surplus is contrary to the definition of depreciation, which is the recovery of an investment ratably (*i.e.,* equally) over its service life to ensure that both present and future customers are treated equitably; that is, they pay only for the portion of the facilities that is used to provide electric service.

Q WHAT IS THE SIGNIFICANCE OF LG&E'S DEPRECIATION RESERVE SURPLUS?

A A depreciation surplus means that the current generation of customers is subsidizing future customers. In other words, there is intergenerational inequity.

Q HOW CAN INTERGENERATIONAL INEQUITY BE RESOLVED?

A Intergenerational inequity can be resolved, thus restoring intergenerational equity, by amortizing a large depreciation reserve surplus over a much shorter time period than the assets' proposed remaining lives.

Q IS AMORTIZING A DEPRECIATION SURPLUS OVER A SHORT TIME PERIOD CONSISTENT WITH ACCEPTED PRACTICE AND PRECEDENT?

A Yes, as discussed later, amortizing surplus depreciation is consistent with accepted regulatory accounting practice and precedent. Further, if properly implemented, it would not violate generally accepted accounting principles.

Background

Q WHAT IS DEPRECIATION?

A Depreciation reflects the consumption or use of assets used to provide utility service. Thus, it provides for capital recovery of a utility's original investment. Generally, this capital recovery occurs over the average service life of the investment or assets. The most commonly used definition of depreciation is found in the Code of Federal Regulations (CFR):

> Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence,

> changes in the art, changes in demand and requirements of public authorities.[3]

In addition, the American Institute of Certified Public Accountants in Accounting Research and Terminology Bulletin #1 provides the following definition of depreciation accounting:

> Depreciation accounting is a system of accounting which aims to distribute cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is the portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.[4]

This definition recognizes depreciation as an allocation of cost to particular accounting periods over the life of assets.

Q WHAT ARE THE KEY PARAMETERS THAT DETERMINE THE AMOUNT OF DEPRECIATION RECOGNIZED FOR RATEMAKING PURPOSES?

A Depreciation accounting provides for the recovery of the original cost of an asset over its life. As a result, it is critical that an appropriate average life be used to develop the depreciation rates so that present and future customers are treated equitably. In addition to the recovery of the original cost, depreciation rates also contain a provision for net salvage. Net salvage is the value of the scrap or reused materials less the cost of removing the asset being depreciated. A utility will reflect in its rates the net salvage over the useful life of the asset.

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[3] *18 CFR Part 101*.

[4] National Association of Regulatory Utility Commissioners (NARUC), *Public Utility Depreciation Practices* at 14 (Aug. 1996).

Q HOW ARE DEPRECIATION RATES CALCULATED?

A Depreciation rates are calculated using the straight-line method. LG&E uses the remaining life technique to calculate the depreciation rates. Remaining life depreciation rates are derived using the following formula:

$$Remaining\ Life\ Rate = \frac{100\%\ - Reserve\ \% - Avg.Future\ Net\ Salvage\ \%}{Avg.Remaining\ Life\ in\ Years}$$

Under this method of developing depreciation rates, the un-depreciated portion of the plant in service, adjusted for net salvage, is recovered over the average remaining life of the asset or group of assets. Therefore, at the end of the useful life, the asset is fully depreciated.

Surplus Depreciation Reserve

Q HOW DID YOU QUANTIFY THE AMOUNT OF THE SURPLUS DEPRECIATION RESERVE?

A The depreciation surplus is quantified in **Exhibit JP-1** for Electric (page 1) and Gas page 2) plant accounts. The information shown in **Exhibit JP-1** may be found in LG&E's depreciation study.[5]

LG&E's depreciation study was based on December 31, 2015, plant balances. The depreciation reserve surplus shown in **Exhibit JP-1** (column 3) is the difference in the book reserve (column 2) and the calculated accrued depreciation (*i.e.,* theoretical reserve), which is shown in column 1. If the book reserve amount is greater than the theoretical reserve a reserve surplus exists. Conversely if the book reserve amount is less than the theoretical reserve, a reserve deficiency exists.

[5] Direct Testimony of John J. Spanos, Exhibit JJS-LG&E-1, Part IX.

Summing the total book reserves and theoretical reserves for all accounts reveals LG&E has accrued a $115.2 million Electric surplus **(Exhibit JP-1**, page 1 column 3) after removing the reserve associated with investment that is separately recovered in the ECR and DSM surcharges and a $28.1 million Gas surplus **(Exhibit JP-1**, page 2, column 3). In other words, based on LG&E's proposed average and the remaining service lives of its investments, LG&E's book depreciation reserve is $115.2 million (Electric) and $28.1 million (Gas) more than the "required" or "theoretical" reserve than the studies show would be appropriate.

Exhibit JP-1, page 1, column 8 shows the proposed future test period accrual for each function, and column 9 shows the years of accruals associated with the surplus reserve. The steam production and distribution functions surplus reserves each represent one year of accruals.

Referring to **Exhibit JP-1**, page 2, column 4 shows the proposed future test period accrual for each gas function, and column 5 shows the years of accruals associated with the surplus reserve. The storage function surplus reserve represents over one year of accruals and the distribution and common functions surplus reserves represent over one-half year of accruals.

Q WHAT IS THE THEORETICAL RESERVE?

A The theoretical reserve is the amount of accumulated depreciation that would have been accrued given the current asset life and net removal cost assumptions employed in LG&E's depreciation study.

Q WHAT IS THE SIGNIFICANCE OF COMPARING THE THEORETICAL AND BOOK DEPRECIATION RESERVES?

A The purpose of depreciation is to recover capital investment, including removal costs. Such recovery should, to the extent possible, come from the customers that use the utility service. Comparing the theoretical reserve to the book reserve is a useful indicator to determine if the utility is appropriately recovering its capital investment ratably over the projected service life. A depreciation surplus indicates that the current generation of ratepayers has paid a disproportionate share of the assets consumed to provide utility services. This would result in subsidizing the service provided to future generations of ratepayers. Intergenerational subsidies are neither fair nor equitable.

Q HOW CAN INTERGENERATIONAL EQUITY BE RESTORED?

A Intergenerational equity can be restored by amortizing a large depreciation reserve surplus over a much shorter time period than the assets' proposed remaining lives.

Q IS THERE ANY DISPUTE OVER THE AMOUNT OF THE DEPRECIATION RESERVE SURPLUS FOR ELECTRIC STEAM PRODUCTION AND DISTRIBUTION PLANT AND FOR GAS STORAGE, DISTRIBUTION AND COMMON PLANT ACCOUNTS?

A No. The theoretical reserve calculations are based on LG&E's proposed depreciation parameters. Thus, the $97.3 million (Electric) and $27 million (Gas) depreciation surplus is based on LG&E's proposed life and net salvage parameters. If lives were understated or the net salvage values overstated, the Electric and Gas surplus would be higher.

Recommendation

Q SHOULD THE COMMISSION ADDRESS LG&E'S DEPRECIATION SURPLUS?

A Yes. The $97.3 million and $27 million surplus depreciation reserves for certain Electric and Gas accounts, respectively, should be addressed now — particularly since LG&E is also proposing to adjust depreciation rates in this case. With LG&E's current customers facing significant rate increases, the Commission should require LG&E to amortize its depreciation reserve surplus over a reasonable period. This will help mitigate the rate increase as well as restore intergenerational equity.

Q OVER WHAT PERIOD SHOULD THE ELECTRIC AND GAS DEPRECIATION SURPLUS BE AMORTIZED?

A Based on the magnitude of the surplus and practices in other states that have also used surplus depreciation to offset a revenue deficiency, I recommend a five-year amortization of the Electric and Gas depreciation surplus.

Q HOW WOULD AMORTIZING A $97.3 MILLION ELECTRIC DEPRECIATION SURPLUS AND $27.0 MILLION GAS DEPRECIATION SURPLUS IMPACT LG&E'S OVERALL REVENUE REQUIREMENT?

A First, it would reduce test-year Electric and Gas depreciation expenses by $19.4 and $5.4 million, respectively. These amounts are derived in **Exhibit JP-2**, page 1 (Electric) and page 2 (Gas).

Second, amortizing the depreciation surplus would necessitate a corresponding increase in the accrual rates. This is because when the theoretical reserve is used instead of the book reserve in the rate calculation, there is more investment to be depreciated over the remaining life. These impacts are shown in **Exhibit JP-3**. Specifically, the forecasted test-year accruals were determined using depreciation rates recalculated using the theoretical reserve values. The accruals calculated using the theoretical reserves are shown in column 4. The accruals using the actual reserve amounts are shown in column 5. As can be seen on **Exhibit JP-3**, page 1, amortizing the $97.3 million Electric surplus would require increasing the accrual rates, thereby increasing Electric depreciation expense by $4.2 million (line 3, column 6). Amortizing the $27 million Gas depreciation would require raising the accrual rates, thereby increasing Gas depreciation expense by $0.5 million as shown on **Exhibit JP-3**, page 2 (line 3, column 3).

Third, the net change in test-year depreciation expense would increase net plant in service. High net plant means a higher return on investment. The revenue requirement impacts of higher net plant are calculated in **Exhibit JP-4**. As can be seen on page 1, the net reduction in Electric depreciation expense calculated in **Exhibits JP-2** and **JP-3** would increase Electric net plant by $19.4 million (line 3). Applying LG&E's proposed rate of return (line 4) and tax conversion factor (line 5) would translate into an additional Electric revenue requirement of $2.3 million (line 6).

Thus, the net impact of amortizing a $97.3 million depreciation surplus would be to reduce LG&E's proposed Electric revenue requirement by $12.9 million (line 8).

Referring to **Exhibit JP-4**, page 2, the net reduction in Gas depreciation expense would increase Gas net plant by $5.4 million (line 3). Applying the same proposed rate of return and conversion factor translates into an additional Gas revenue requirement of $0.7 million (line 6). Therefore, the net impact of amortizing a $27.0 million Gas depreciation surplus would be to reduce LG&E's proposed Gas revenue requirement by $4.2 million (line 8).

Q WHAT WOULD BE THE CONSEQUENCE OF ALLOWING THE ELECTRIC AND GAS DEPRECIATION SURPLUS TO SELF-CORRECT OVER THE NEXT 23-39 YEARS?

A Without a mid-course correction, the current generation of customers would pay more for the investment required to provide electricity service. Likewise, future customers would underpay for the investment used to provide service. Thus, the consequence would be to force current customers to subsidize future ones, thereby perpetuating intergenerational inequity.

Q WOULD YOUR PROPOSED MID-COURSE CORRECTION VIOLATE STRAIGHT-LINE DEPRECIATION?

A No. The affected assets would continue to be depreciated on a straight-line basis, albeit at a lower rate, for the next five years. This is illustrated in **Exhibit JP-5**.

Q PLEASE EXPLAIN EXHIBIT JP-5.

A **Exhibit JP-5** illustrates how amortizing a depreciation surplus would restore intergenerational equity. The illustration is based on a $100 asset that is initially assumed to have a 20-year life span. Ignoring removal costs and salvage, annual depreciation expense would be $5 as shown in **Exhibit JP-5**, page 1. In year 10, the utility has accumulated a $50 depreciation reserve. However, it then determines that the remaining life of the asset is 30 years. Thus, the theoretical reserve is $33.30 thereby resulting in a $16.70 surplus, as shown in **Exhibit JP-5**, page 2.

Let's assume that a mid-course correction is made beginning in Year 11 by amortizing the depreciation surplus over five years. This is shown in **Exhibit JP-5**, page 3. As can be seen, annual depreciation expense would be zero in years 11-15. Thereafter, the annual expense would increase to $3.30 for years 16-30. More importantly, as shown on lines 26 and 27, by implementing the mid-course correction, customers in years 1-15 would pay the same amount for the asset as customers in years 16-30. In other words, there would be intergenerational equity.

This would not occur under the remaining life method, as shown in **Exhibit JP-5**, page 4. As can be seen, customers in years 1-15 would pay two-thirds of the cost, while customers in years 16-30 would pay only one-third of the cost. In other words, the remaining life method would not result in a systematic and rational allocation.

Q IS AMORTIZING A SURPLUS DEPRECIATION RESERVE AN ACCEPTED PRACTICE?

A Yes. The NARUC Public Utility Depreciation Practices Manual states:

> The use of an annual amortization over a short period of time or the setting of depreciation rates using the remaining life technique are two of the most common options for eliminating the imbalance.[6]

As previously stated, the remaining life method would not correct the surplus for 23 to 39 years. Thus, the remaining life method will not provide either a timely or an adequate remedy to the intergenerational inequity created by LG&E's large

[6] NARUC, *Public Utility Depreciation Practices August 1996* at 189.

depreciation surplus. For this reason, an annual amortization over a short time period would be the more appropriate measure to restore intergenerational equity.

Q IS THERE ANY PRECEDENT FOR REQUIRING A UTILITY TO USE ITS SURPLUS DEPRECIATION RESERVE TO MITIGATE A RATE INCREASE?

A Yes. The same technique was proposed by Georgia Power Company (GPC) and approved by the Georgia Public Service Commission (GPSC) to bring GPC's 2009 and 2010 earnings to within the earnings band approved in its 2007 rate case.[7]

The Florida Public Service Commission (FPSC) adopted the same recommendation in the most recent rate cases involving Florida Power & Light Company (FPL) and Progress Energy Florida (PEF).[8] Specifically, FPL was ordered to use a $1.2 billion surplus to offset unrecovered capital costs and to amortize the remaining surplus over four years. PEF was ordered to amortize a portion of its $690 million surplus reserve. In both cases, the objective was to negate large base rate increases. In its Order in the FPL case, the FPSC stated:

> In conclusion, each account's book reserve shall be brought to its calculated theoretically correct level. Of the $1,208.8 million bottom-line reserve surplus, $314.2 million shall be used to offset the unrecovered costs associated with the capital recovery schedules of near-term retiring investments. The remaining reserve surplus of $894.6 million shall be amortized over a 4-year period, beginning January 1, 2010.[9]

[7] *Georgia Power Company Request for an Accounting Order to Amortize a Portion of Its Regulatory Liability for Accrued Removal Costs*, Docket No. 25060, Order Adopting Stipulation.

[8] Progress Energy was merged into Duke Power. The successor company is named Duke Energy Florida.

[9] *In re: Petition For Increase In Rates By Florida Power & Light Company*, Docket No. 080677-EI, Order No. PSC-10-0153-FOF-EI at 87.

The FPSC's Order in the PEF case stated:

> Balancing the need to correct the reserve surplus with concerns regarding reduced cash flow and financial integrity, we find that $23 million of the reserve surplus shall be amortized over four years in the annual amount of $5,840,613, thereby bringing the increase in annual revenue requirement to zero. The remaining $667 million reserve surplus shall be recovered through the remaining life rate design.[10]

The Minnesota Public Utilities Commission approved an eight-year amortization of a $265 million surplus depreciation reserve for Northern States Power (NSP).[11] Just recently, the Alabama Public Service Commission voted to use a surplus in Alabama Power Company's cost of removal reserve to offset a $142 million under-collection under Rate CNP-B (Certified New Plant: Purchased Power).[12]

Q HOW DID PROGRESS ENERGY FLORIDA MAKE USE OF ITS REMAINING RESERVE SURPLUS?

A In 2010, the FPSC approved a Stipulation and Settlement Agreement that requires PEF to maintain the currently approved base rates. To accomplish this, PEF was allowed discretion to use the remaining surplus by reducing depreciation expense by up to $150 million in 2010, up to $250 million in 2011, and up to any remaining balance in 2012 until the earlier of when the surplus reaches zero or the term of the

[10] *In re: Petition For Increase In Rates By Progress Energy Florida, Inc*., Docket No. 090079-EI, Order No. PSC-10-0131-FOF-EI at 52.

[11] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*; Docket No. E-002/GR-12-961, Findings of Fact, Conclusions and Order at 26, 28-29 (Sept. 3, 2013).

[12] Alabama Power Company, Docket No. U-5208, Order (Feb. 17, 2017).

Agreement expires.[13]

Q IS LG&E'S SURPLUS DEPRECIATION RESERVE COMPARABLE IN MAGNITUDE TO NORTHERN STATES POWER, FLORIDA POWER & LIGHT AND PROGRESS ENERGY FLORIDA?

A LG&E's depreciation surplus is somewhat smaller as shown in the table below.

Surplus Reserve Depreciation
(Dollars in Millions)

Description	LG&E* Electric	LG&E Gas	NSP	FPL	PEF
Accumulated Book Depreciation	$1,714	$331	$3,846	$10,915	$4,529
Theoretical Depreciation	$1,599	$303	$3,251	$9,669	$3,740
Reserve Surplus	$115	$28	$595	$1,246	$789
Surplus as a % of Book Depreciation	7%	8%	15%	11%	17%

*Includes all plant accounts.

However, LG&E is seeking substantial rate increases. Further intergenerational inequity is still a concern. This justifies similar immediate action to restore intergenerational equity and to help mitigate the impact of both pending and future base rate increases.

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[13] *In re: Petition For Increase In Rates By Progress Energy Florida, Inc*. Docket No. 090079-EI, *In re: Petition For Limited Proceeding To Include Bartow Repowering Project In Base Rates, By Progress Energy Florida, Inc*., Docket No. 090144-EI, *In re: Petition For Expedited Approval Of The Deferral Of Pension Expenses, Authorization To Charge Storm Hardening Expenses To The Storm Damage Reserve, And Variance From Or Waiver Of Rule 25-6.0143(1)(c), (d), and (f), F.A.C., by Progress Energy Florida, Inc*., Docket No. 090145-EI; *In re: Petition for Approval of an Accounting Order to Record a Depreciation Expense Credit , by Progress Energy Florida, Inc.,* Docket No. 100136-EI, Order No. PSC-10-0398-S-EI, Order Approving Stipulation and Settlement, Att. 1 at 3 (Jun. 18, 2010).

Q DO THE ALABAMA, FLORIDA, GEORGIA AND MINNESOTA COMMISSIONS USE THE REMAINING LIFE METHOD IN SETTING DEPRECIATION RATES FOR THE UTILITIES THAT THEY REGULATE?

A Yes.

Q WHY ELSE SHOULD LG&E'S LARGE DEPRECIATION SURPLUS BE APPLIED IN THIS CASE?

A As was the case in Alabama, Florida and Minnesota, a depreciation surplus can be used to mitigate rate increases, such as LG&E is proposing in this case. Further, it is consistent with setting rates that are just and reasonable and reflect a utility's cost of service. And finally, using surplus depreciation is not a disallowance. LG&E will continue to have a reasonable opportunity to recover its used and useful investment. The only difference is that there will be a better matching between cost recovery and the customers utilizing electricity service.

Q PLEASE SUMMARIZE YOUR RECOMMENDATION ON DEPRECIATION EXPENSE.

A Consistent with accepted practice and precedent, the Commission should lower LG&E's test-year electric revenue requirement by $12.9 million to amortize a $97.3 million accumulated Electric depreciation reserve surplus over five years. Further, LG&E's test-year gas revenue requirement should be reduced by $4.2 to amortize a $27.0 million accumulated Gas depreciation reserve surplus over the same five year span. Not only would this help to mitigate LG&E's proposed rate increase, it would also restore intergenerational equity.

Incentive Compensation

Q WHAT IS MEANT BY INCENTIVE COMPENSATION?

A Incentive compensation is the additional compensation paid to employees to encourage certain behavior and/or results. It is paid as a reward to an individual and/or business group contingent upon achievement of pre-established goals and objectives.

Q IS INCENTIVE COMPENSATION TYPICALLY AN ISSUE IN SETTING RATES?

A Yes. Not all incentive compensation benefits ratepayers. As discussed later, incentive compensation based on achieving certain operational goals may be a reasonable and necessary expense which may benefit ratepayers. However, incentive compensation targeted to achieve certain financial goals is only for the benefit of shareholders and provides little, if any, benefit to ratepayers. Thus, the latter expenses should not be charged to ratepayers.

Q IS LG&E SEEKING TO RECOVER INCENTIVE COMPENSATION ASSOCIATED WITH ACHIEVING CERTAIN FINANCIAL GOALS IN THIS PROCEEDING?

A Not directly. However, LG&E is proposing rates based on a substantial increase in the amount of incentive compensation expense that it projects to payout for achieving operational goals. Furthermore, the projected increase is so disproportionate relative to the corresponding projected increase in wages and salaries it would also provide implicit recovery of incentive compensation to achieve financial goals.

LG&E's Proposal

Q IS LG&E PROPOSING TO RECOVER COSTS INCURRED UNDER ITS INCENTIVE COMPENSATION PROGRAM IN BASE RATES?

A Yes. LG&E has included $10.9 million of incentive compensation expenses in the test year.

Q SHOULD LG&E BE ALLOWED FULL RECOVERY OF ALL PROJECTED INCENTIVE COMPENSATION PAYMENTS?

A No. First, LG&E has overstated its test-year incentive compensation expense. Second, to the extent that any of this overstated expense may be indirectly related to incentive compensation that is paid out based on achieving certain financial goals such as achieving net income or earnings levels, this expense should be disallowed because it benefits only shareholders not customers.

Q WHAT INCENTIVE COMPENSATION PLAN DOES LG&E OFFER ITS EMPLOYEES?

A LG&E offers its employees the Team Incentive Award Plan (TIA). Past years and proposed test-year expenses for each goal category are listed on **Exhibit JP-6**.

Q WHAT IS THE TIA INCENTIVE PLAN?

A The TIA Plan provides for an annual award payout based on the achievement of financial and operational targets.

Q WHAT PERFORMANCE MEASURES TRIGGER PAYOUTS UNDER THE TIA?

A In general, the payouts under the TIA are based on the financial measures of net income and cost control and the operating measures of customer reliability and satisfaction, corporate safety and individual and team effectiveness. As can be seen in **Exhibit JP-6**, the TIA accounts for $10.9 million of test-year expense.

Q HOW IS THE FUNDING AMOUNT FOR THE TIA DETERMINED?

A The funding level for the TIA is based on a weighting of individual measures. LG&E has noted in discovery that these incentive measures are re-evaluated annually.[14] The targeted awards are based on the following levels:

Target Award Participation[15]	
Employee Group	**Target**
Non-Exempt and Hourly	6% of annual earnings
Exempt Individual Contributors	9% of base salary
Managers	14% of base salary
Senior Managers	25% of base salary

As the table demonstrates, the target awards for employees other than non-exempt and hourly are proportional to base salaries.

Q IS THERE ANYTHING UNUSUAL ABOUT THE $10.9 MILLION TEST-YEAR EXPENSE?

A Yes. Although LG&E is projecting a $10.9 million (11.2%) increase in test-year expense, the base year expense included $2.5 million of payouts associated with achieving net income goals (**Exhibit JP-6**, line 1). The corresponding test-year expense is zero. In order to achieve the projected $10.9 million test-year expense, LG&E would have to increase the incentive compensation expense associated with achieving the other (non-financial) goals by almost 49% (**Exhibit JP-6**, line 8). A

[14] LG&E's Response to KIUC 1-19.

[15] LG&E's Response to AG 1-210.

49% increase is many times the projected wage and salary increase.

Q IS A 49% INCREASE IN TEST-YEAR INCENTIVE COMPENSATION EXPENSE REASONABLE?

A No. As demonstrated above, incentive compensation is related to salaries. However, LG&E's projected wages and salaries are not increasing by anywhere near 49%. This excessive increase in test-year incentive compensation expense cannot be explained solely by higher payouts for achieving operational goals.

Therefore, I conclude that some portion of the test-year incentive compensation expense is related to achieving financial goals.

Q HAS THIS COMMISSION PREVIOUSLY DETERMINED THAT INCENTIVE COMPENSATION FOR ACHIEVING FINANCIAL GOALS SHOULD BE DISALLOWED?

A Yes. In a recent Kentucky Power Company rate case (Case No. 2014-00396) the Commission stated:

> Incentive criteria based on a measure of EPS, with no measure of improvement in areas such as service quality, call-center response, or other customer-focused criteria are clearly shareholder oriented. As noted in Case No. 2013-00148, the Commission has long held that ratepayers receive little, if any, benefit from these types of incentive plans.[74] [footnote omitted] It has been the Commission's practice to disallow recovery of the cost of employee incentive plans that are tied to EPS or other earnings measures and we find that Kentucky Power's argument to the contrary does nothing to change this holding as it is unpersuasive.[16]

[16] *In the Matter of: Application of Kentucky Power Company For: (1) a General Adjustment of its Rates for Electric Service; (2) an Order Approving its 2014 Environmental Compliance Plan; (3) an Order Approving its Tariffs and Riders; and (4) an Order Granting all other Required Approvals and Relief*, Case No. 2014-00396, Order at 13 (Jun. 22, 2015).

Q HAVE OTHER STATE REGULATORS SIMILARLY DISALLOWED INCENTIVE COMPENSATION THAT IS TARGETED TO ACHIEVING FINANCIAL OBJECTIVES?

A Yes. The table below summarizes the most recent decisions by regulators in surrounding states that have disallowed (either in whole or in part) financially-based forms of incentive compensation.

Recent Orders Disallowing Financially-Based Incentive Compensation in Litigated Proceedings			
State	**Docket No.**	**Utility**	**Date**
Arkansas	15-015-U	Entergy Arkansas	2/23/2016
Kansas	10-KCPE-415-RTS	Kansas City Power and Light	11/22/2010
Louisiana	U-20925	Entergy Louisiana	5/25/2005
Missouri	ER-2014-0370	Kansas City Power and Light	9/2/2015
Oklahoma	PUD 201100034	Oklahoma Natural Gas	7/5/2011
Texas PUC	43695	Southwestern Public Service	2/23/2016

Thus, this Commission's policy aligns with the practices in most surrounding states.

Recommendation

Q WHAT DO YOU RECOMMEND?

A Incentive compensation awards only tied to corporate earnings objectives should be disallowed. In addition, LG&E's rates should not assume an exponential increase in the allowable incentive compensation expense.

Q WHAT ADJUSTMENT SHOULD BE MADE TO LG&E'S PROPOSED TEST-YEAR INCENTIVE COMPENSATION EXPENSE?

A I recommend that test-year TIA expense should reflect the same proposed general wage increase that LG&E has included in its proposed revenue requirement, which is [redacted]%.[17] Based on this assumption, I recommend that the Commission disallow $[redacted] million of the proposed LG&E TIA expenses. The derivation of the $[redacted] million disallowance is shown in **Exhibit JP-6**.

The $[redacted] million adjustment assumes that test-year TIA expense would be [redacted]% higher than base year expense. This assumption is consistent with LG&E's projected wage and salary increases. This results in a test-year expense of $[redacted] million (line 10), which is $[redacted] million (line 11) below the $10.9 million expense (line 8) projected by LG&E.

Q WHAT IS THE IMPACT OF THIS DISALLOWANCE ON THE ELECTRIC AND GAS COST OF SERVICE?

A The following table shows the allocation of the $[redacted] million disallowance between Electric and Gas operations. The allocation was based on the total amount of test-year Electric and Gas labor expenses.

Incentive Compensation Disallowance
Allocated Between Electric and Gas Operations
($ in Millions)[18]

Item	Total Company	Electric Operations	Gas Operations
Total Labor Expense	$97.4	$71.5	$25.9
Allocation Factors	100.0%	73.4%	26.6%
Disallowance	[redacted]	[redacted]	[redacted]

LG&E's Electric and Gas operations account for $71.5 million and $25.9 million of labor expense. These represent 73.4% and 26.6% of the total LG&E labor expense,

[17] LG&E's Response to PSC No. 36 – Confidential.

[18] Electric Cost of Service Study: LG&E's Response to PSC 2- 111; Gas Cost of Service Study: LG&E's Response to PSC 1-53.

respectively. Accordingly, $[redacted] million of the disallowed incentive compensation expense should apply to Electric while $[redacted] million should apply to Gas operations.

Cash Working Capital

Q WHAT IS CASH WORKING CAPITAL?

A Cash working capital is defined as follows:

> The average amount capital provided by investors, over and above the investment in plant and other specifically measured rate base items, to bridge the gap between the time expenditures are required to provide services and the time collections are received for such services.[19]

In other words, cash working capital functions, in connection with other rate base items, to measure the amount of investors' supplied capital required to provide service.

Q HAVE YOU REVIEWED LG&E'S PROPOSED CASH WORKING CAPITAL ALLOWANCE?

A Yes. LG&E is proposing to use a variation of the "45-day formula" which was widely used by FERC and other state regulatory commissions. LG&E's variation of the formula is 1/8th of the total operation and maintenance (O&M) expense, excluding purchased power and ECR related expenses.

Q IS THIS THE ONLY VARIATION OF THE 45-DAY FORMULA?

A No. In the absence of a lead-lag study to determine cash working capital, FERC will accept a different variation of the 45-day formula. Specially, FERC's 45-day formula

[19] Robert L. Hahne and Gregory Aliff, Accounting for Public Utilities, Section 5.04 (November, 2010).

uses 1/8th of the annual O&M expense minus fuel and purchased power expenses.[20] In other words, all fuel expense is removed. Other commissions have also used a similar approach.[21]

Q WHAT IS THE DIFFERENCE BETWEEN THE TWO VARIATIONS OF THE 45-DAY FORMULA?

A The difference between LG&E's and other commissions' application of the 45-day formula is that LG&E includes fossil fuel expense whereas FERC and other state regulatory commissions exclude fossil fuel expense.

Q WHICH VARIATION OF THE 45-DAY FORMULA IS MORE APPROPRIATE?

A The more appropriate variation is to exclude all fuel and purchased power expenses as well as other expenses (*e.g.,* ECR) that are recovered in separate surcharge mechanisms. First, LG&E is already including fossil fuel investment (Fuel Stock) as part of its rate base. Second, the Fuel Adjustment Clause (FAC) provides for timely adjustments in the cost of fuel and purchased power costs. The FAC is adjusted monthly to reflect fluctuations in these costs. Hence, LG&E is recovering its fuel expenses on a current basis. Accordingly, it is unnecessary to also include a working capital allowance for fossil fuel expense.

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[20] Trans-Elect NTD Path 15, LLC, Docket No. ER05-17-002, Initial Decision at 31 (Dec. 21, 2005); Xcel Energy Southwest Transmission Company, LLC, Docket No. ER14-2751-000, Order on Transmission Formula Rate Proposal and Incentives, Accepting, and Suspending Filing, and Establishing Settlement and Hearing Judge Procedures at 41 (Nov. 26, 2014).

[21] *Monongahela Power Company In the Matter of Increased Rates and Charges*, Case No. 8127 at 6 (Mar. 18, 1977), *In Re: Petition of Tampa Electric Company for an Increase in its Rates and Charges*, Docket No. 760846-EU, Order Authorizing Certain Increase at 9 (Oct. 4, 1977), *In the Matter of the Application of Indiana & Michigan Electric Company for Authority to Increase its Rates for the Sale of Electric Energy*, Case no. U-6148, Opinion and Order at 28 (May 12, 1981).

Q WHAT DO YOU RECOMMEND?

A The Commission should remove all fuel expense, including fossil fuel, in the application of the 45-day formula. A revised cash working capital calculation, with all fuel and purchased power expense removed, is provided in **Exhibit JP-7**. The effect of this recommendation would be to reduce LG&E's Electric revenue deficiency by $4.1 million (line 12).

AMS Costs

Q HAVE YOU REVIEWED LG&E'S PROPOSAL TO DEPLOY AMS METERS THROUGHOUT ITS SERVICE AREA?

A Yes. LG&E is seeking Commission approval of a Certificate of Public Convenience and Necessity and cost recovery beginning in this rate case for its proposal to fully deploy AMS meters throughout its service area. According to LG&E, deployment would commence in the third quarter of 2017. This is within the timeframe of its fully-forecasted test year in this rate case.

Q HAS LG&E PROJECTED THE OVERALL COST OF DEPLOYING AMS METERS?

A Yes. LG&E states that it will incur total capital costs of $119 million (Electric) and $55 million (Gas), and deployment-related O&M expenses of $13.0 million (Electric) and $2.5 million (Gas) through the year 2021.[22] The deployment will also mean replacing all of the existing (non-AMS) meters. LG&E is proposing to establish a $12.1 million (Electric) regulatory asset which reflects its estimate of the amount of

[22] Direct Testimony of John P. Malloy at 17.

unrecovered costs associated with the existing meters.[23]

Q IS LG&E PROPOSING ANY SPECIFIC PRO-FORMA ADJUSTMENTS TO TEST-YEAR REVENUE REQUIREMENTS TO RECOGNIZE THE AMS DEPLOYMENT?

A Yes. The AMS deployment includes $22.7 (Electric) and $12.2 million (Gas) of additional plant investment and $2.92 million (Electric) and approximately $0.5 million (Gas) of additional O&M expense.[24]

Q WHY IS LG&E INCURRING THE SUBSTANTIAL COSTS OF FULLY DEPLOYING AMS METERS?

A LG&E suggests that the AMS deployment will provide $1.02 billion of benefits (in nominal dollars) to its customers through the year 2039.[25] This would more than offset the projected cost by about $470 million (in nominal dollars).[26] Note: these amounts are combined for KU, LG&E Electric, LG&E Gas and Old Dominion Power Company.

Q WHAT SPECIFIC COSTS AND BENEFITS ARE LG&E PROJECTING WITH ITS AMS DEPLOYMENT?

A The LG&E-Electric specific cost benefit analysis is shown in **Exhibit JP-8,** page 1. As can be seen, electric AMS deployment is projected to cost $188.7 million (line 25, sum of columns 1-3) but it is expected to produce benefits of $360.2 million (line 25, column 4), thereby resulting in $171.5 million (line 25, column 5) of net benefits (all in

[23] Direct Testimony of Christopher M. Garrett at 43.

[24] Schedule B-2.3 at 5 and Schedule D-1 at 5-6.

[25] Direct Testimony of John P. Malloy, JPM-1 at 31.

[26] *Id.* at 17.

nominal dollars). Further, the projected benefits, which are principally O&M savings, are not projected to begin flowing until 2019 – this is after the test year.

The LG&E-Gas specific cost-benefit analysis is shown in **Exhibit JP-8**, page 2. As can be seen the gas AMS deployment is projected to cost $72.8 million (line 25, sum of columns 1-3) but it is expected to produce benefits of $65.6 million (line 25, column 4), thereby resulting in $7.2 million (line 25, column 5) of net benefits (all in nominal dollars). Further, the projected benefits, which are principally O&M savings, are not projected to begin flowing until 2019 – this is after the test year.

Q HAS LG&E PROPOSED ANY MECHANISM FOR FLOWING THROUGH ANY OF THE PROJECTED BENEFITS OF THE AMS DEPLOYMENT TO ITS CUSTOMERS?

A No.

Q YOU PREVIOUSLY STATED THAT LG&E IS PROPOSING TO CREATE A REGULATORY ASSET TO RECOVER THE COST OF EXISTING METERS. HOW WOULD THE CREATION OF THIS REGULATORY ASSET AFFECT RATES?

A LG&E's proposal to create a regulatory asset is intended to defer recovery of the cost of the existing meters until the cost savings associated with the AMS deployment are realized.[27]

Q DO YOU HAVE ANY CONCERNS ABOUT LG&E'S COST RECOVERY PROPOSALS?

A Yes. Although LG&E is reserving the right to flow additional costs associated with

[27] Direct Testimony of Christopher M. Garrett at 45.

the AMS deployment to customers (*i.e*., the unrecovered cost of existing meters), it is not similarly proposing any mechanism to flow any of the projected savings of the AMS deployment to customers. As can be seen in **Exhibit JP-8**, LG&E is projecting $13.2 million in Electric O&M savings (page 1, lines 4-5) and $2.7 million and $2.8 million in Gas O&M savings (page 2, lines 4-5) in the years 2019 and 2020, respectively. These translate into about $16 million per year.

Q IN THE ABSENCE OF A SPECIFIC MECHANISM, HOW WOULD THE PROJECTED O&M SAVINGS FLOW THROUGH?

A Absent a specific mechanism or another rate case, LG&E's projected $13.2 million (Electric) and $2.75 million (Gas) of O&M savings for the years 2019 and 2020 would flow through to LG&E's operating income. Effectively, this would deny customers from receiving any of the benefits of the AMS deployment until LG&E's next rate case.

Q WHAT DO YOU RECOMMEND?

A To better match the costs and benefits of what is arguably a substantial undertaking by LG&E, LG&E's retail revenue requirement should be reduced by $13.2 million (Electric) and $2.75 million (Gas) which are the averages for each plant during the years 2019 and 2020. My recommendation would ensure that customers receive the projected benefits of the proposed AMS deployment prior to the next rate case. Further, requiring LG&E to flow through the expected benefit in the rates to be approved in this case, would also provide LG&E an incentive to maximize the actual benefits achieved from the AMS deployment.

3. CLASS COST-OF-SERVICE STUDY: ELECTRIC

Q HAS LG&E FILED ANY CLASS COST-OF-SERVICE STUDIES IN THIS CASE?

A Yes. LG&E filed two Electric CCOSSs and a Gas CCOSS.[28] Both Electric CCOSSs are identical in all respects except for the method of allocating production plant and related operating expenses. The two production plant allocation methods used by LG&E are:

- Base-Intermediate-Peak (BIP) method; and
- Loss of Load Probability (LOLP) method

Of the two methods used, LG&E is supporting the LOLP method because it is consistent with how LG&E plans generation capacity to provide reliable service to its customers.[29]

Q WHAT ISSUES ARE YOU ADDRESSING ON LG&E'S PROPOSED CLASS COST-OF-SERVICE STUDIES?

A I am addressing the overall structure of each CCOSS filed by LG&E, as well as the issues surrounding the two proposed production plant allocation methods. I am not addressing the allocation of any specific costs.

Q BASED ON YOUR REVIEW, DO THE TWO CLASS COST-OF-SERVICE STUDIES FILED BY LG&E IN THIS CASE GENERALLY COMPORT WITH ACCEPTED PRACTICE?

A Yes. Both CCOSSs are both structurally sound and generally recognize the ways

[28] LG&E's Gas CCOSS is discussed in Part 5.

[29] Testimony of Robert M. Conroy at 6.

that costs are incurred to serve each of the various customer classes, including the differences in class service and load characteristics that support charging different average rates per kWh. These differences are explained later.

<u>Background</u>

Q WHAT IS A CLASS COST-OF-SERVICE STUDY?

A A CCOSS is an analysis used to determine each class's responsibility for the utility's costs. Thus, it determines whether a class generates sufficient revenues to recover the class's cost of service. A CCOSS separates the utility's total costs into portions incurred on behalf of the various customer groups. Most of a utility's costs are incurred to jointly serve many customers. For purposes of rate design and revenue allocation, customers are grouped into homogeneous classes according to their usage patterns and service characteristics.

Q WHAT PROCEDURES ARE USED TO CONDUCT A CLASS COST-OF-SERVICE STUDY?

A The basic procedure for conducting a CCOSS is fairly simple. First, we identify the different types of costs (*functionalization*), determine their primary causative factors (*classification*), and then apportion each item of cost among the various rate classes (*allocation*). Adding up the individual pieces gives the total cost for each class.

Identifying the utility's different levels of operation is a process referred to as *functionalization*. The utility's investments and expenses are separated into production, transmission, distribution, and other functions. To a large extent, this is done in accordance with the Uniform System of Accounts (USOA) developed by FERC.

Once costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as *classification*. Costs are classified as demand-related, energy-related or customer-related. Demand (or capacity) related costs vary with peak demand, which is measured in kilowatts (kW). This includes production, transmission, and some distribution investment and related fixed O&M expenses. As explained later, peak demand determines the amount of capacity needed for reliable service. Energy-related costs vary with the production of energy, which is measured in kilowatt-hours (kWh). Energy-related costs include fuel and variable O&M expense. Customer-related costs vary directly with the number of customers, and include expenses such as meters, service drops, billing, and customer service. In addition, LG&E also classifies a portion of the distribution network as customer-related.

Each functionalized and classified cost must then be *allocated* to the various customer classes. This is accomplished by developing allocation factors that reflect the percentage of the total cost that should be paid by each class. The allocation factors should reflect *cost causation*; that is, the degree to which each class caused the utility to incur the cost.

Q WHAT KEY PRINCIPLES ARE RECOGNIZED IN A CLASS COST-OF-SERVICE STUDY?

A A properly conducted CCOSS recognizes two key cost-causation principles. First, customers are served at different delivery voltages. This affects the amount of investment the utility must make to deliver electricity to the meter. Second, since cost causation is also related to how electricity is used, both the timing and rate of energy consumption (*i.e.*, demand) are critical. Because electricity cannot be stored for any significant time period, a utility must acquire sufficient generation resources and construct the required transmission facilities to meet the maximum projected demand, including a reserve margin as a contingency against forced and unforced outages, severe weather, and load forecast error. Customers that use electricity during the critical peak hours cause the utility to invest in generation and transmission facilities.

Q WHAT FACTORS CAUSE THE PER-UNIT COSTS TO DIFFER BETWEEN CUSTOMER CLASSES?

A Factors that affect the per-unit cost include whether a customer's usage is constant or fluctuating (load factor), whether the utility must invest in transformers and distribution systems to provide the electricity at lower voltage levels, and the amount of electricity that a customer uses. In general, some customers are less costly to serve on a per unit basis when they:

1. Operate at higher load factors;
2. Take service at higher delivery voltages; and
3. Use more electricity per customer.

For example, the difference in the losses incurred to deliver electricity at the various delivery voltages is a reason why the per-unit energy cost to serve is not the same for all customers. More losses occur to deliver electricity at distribution voltage (either primary or secondary) than at transmission voltage, which is generally the level at which industrial customers take service. This means that the cost per kWh is lower for a transmission customer than a distribution customer. The cost to deliver a kWh at primary distribution, though higher than the per-unit cost at transmission, is also lower than the delivered cost at secondary distribution.

In addition to lower losses, transmission customers do not use the distribution system. Instead, transmission customers construct and own their own distribution systems. Thus, distribution system costs are not allocated to transmission level customers who do not use that system. Distribution customers, by contrast, require substantial investments in these lower voltage facilities to provide service. Secondary distribution customers require more investment than do primary distribution customers. This results in a different cost to serve each type of customer.

Two other cost drivers are efficiency and size. These drivers are important because most fixed costs are allocated on either a demand or customer basis.

Efficiency can be measured in terms of load factor. Load factor is the ratio of average demand (*i.e.*, energy usage divided by the number of hours in the period) to peak demand. A customer that operates at a high load factor is more efficient than a lower load factor customer because it requires less capacity for the same amount of energy. For example, assume that two customers purchase the same amount of energy, but one customer has an 80% load factor and the other has a 40% load factor. The 40% load factor customers would have twice the peak demand of the 80% load factor customers, and the utility would therefore require twice as much capacity to serve the 40% load factor customer as the 80% load factor. Said differently, the fixed costs to serve a high load factor customer are spread over more kWh usage than for a low load factor customer.

Production Plant Allocation

Q YOU PREVIOUSLY STATED THAT LG&E FILED TWO CLASS COST-OF-SERVICE STUDIES USING DIFFERENT PRODUCTION PLANT ALLOCATION METHODS. WHICH METHOD DOES LG&E PREFER?

A LG&E's preferred CCOSS uses the LOLP method. In addition, LG&E filed a BIP study because this is the method that the Commission has preferred in past cases.

Q WHAT IS THE LOLP METHOD?

A LOLP is a variant of the coincident peak (CP) method of allocation. CP allocates costs based on each class's demand(s) that occur(s) coincident with the system peak(s). The system peaks used in a CP allocation typically reflect the load characteristics of the utility. For example, summer peak demands would be used to allocate costs under a CP method if the utility in question has a predominant summer system peak. Winter peak demands would be used to allocate costs under a CP method if the utility in question has a predominant winter system peak. A utility having both summer and winter peaks might employ an average of the summer and winter CPs.

LOLP is similar except that instead of choosing the specific peak hours to derive an allocation factor, the critical peak hours are already identified. As explained by Mr. Seelye:

> LOLP represents the probability that a utility system's total demand will exceed its generation capacity during a given hour. Loss of load

> probability therefore takes into consideration the magnitude of the load, installed generation capacity, forced outage rates, maintenance schedules, and ramp-up rates of generating units. LOLP can be calculated for any period – an hour, a day, a week, etc. LOLP is a critical measurement used by KU and LG&E in planning its generation resources. Specifically, it is used to evaluate the level of reserve margins that the Companies target.
>
> For the cost of service study, LOLP was calculated for each hour of the test year based on the hourly loads for the test year and the characteristics of KU and LG&E's generating facilities, including capacity, forced outage rates, and maintenance schedules. Hourly loads for each rate class were then weighted by the LOLP for each hour to determine LOLP weighted hourly load for each rate class. The weighted loads for each rate class are then summed for the test year to determine a production fixed cost allocator.[30]

Thus, LOLP spreads production plant costs over the hours that LG&E considers to be critical from a planning perspective.

Q WHAT IS THE BASE-INTERMEDIATE-PEAK METHOD?

A The BIP method allocates production plant-related costs in a manner that reflects that supply role played by each specific generating unit. The supply roles are defined as base load, intermediate, and peaking.

Thus, the first step in the BIP method is to separate the costs of power plants that operate as base load, intermediate or peaking units. Base load units typically operate throughout the year. Intermediate and peaking units operate when needed to follow load or when other units are experiencing outages. The fixed costs are then assigned based on their supply role. For example, the fixed costs associated with base load units are assigned throughout the year (*i.e.,* base period), while the corresponding fixed costs of intermediate and peaking units are allocated to either

[30] Direct Testimony of William Steven Seelye at 90-91.

the summer and/or winter peak periods. This process resulted in assigning LG&E's production fixed costs as follows:

- Base period: 34.38%.
- Winter peak period: 36.02%.
- Summer peak period: 29.60%[31]

The second step is to allocate the period costs to customer classes. LG&E's proposed class allocations are as follows:

- Base period: Average demand, which is the energy at the source divided by the hours in the test year.
- Winter peak period: Winter coincident peak.
- Summer peak period: Summer coincident peak.

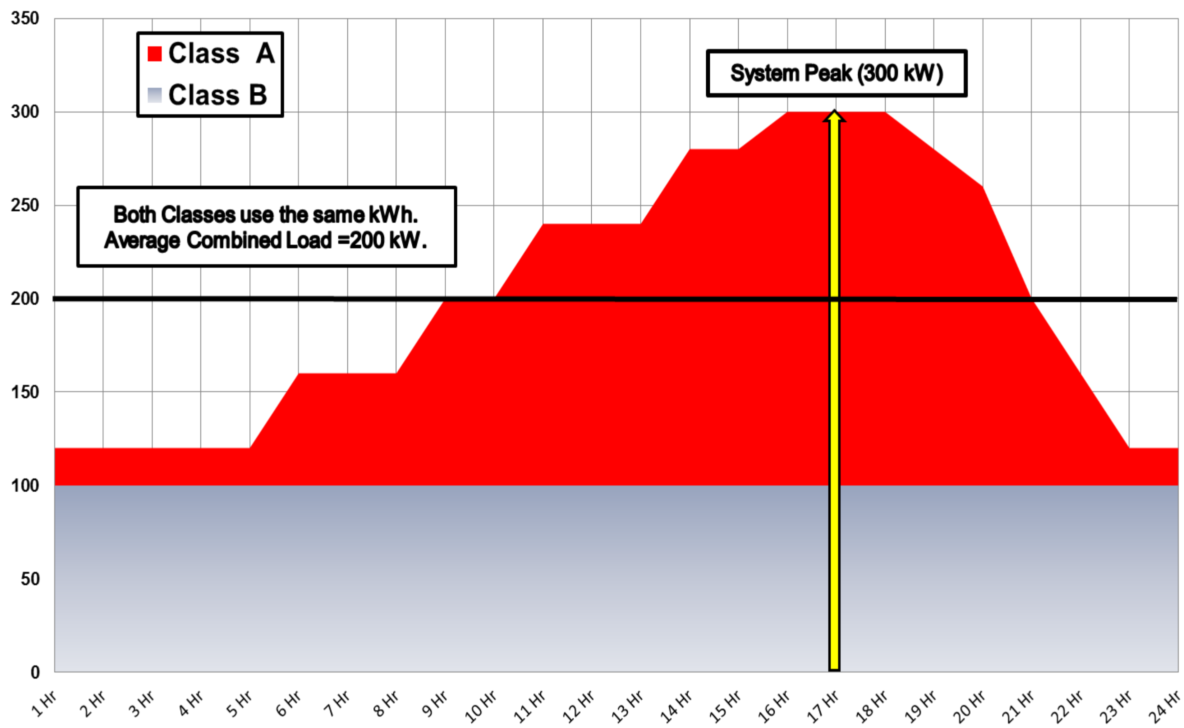
Thus, the most significant difference between LOLP and BIP is that BIP is, in part, a pure energy allocator.

Q WHICH METHOD, LOLP OR BIP, REFLECTS COST CAUSATION?

A In my opinion, LOLP reflects cost causation. This is because LOLP recognizes LG&E's obligation to serve. The obligation to serve means that when customers flip the switch, the light or air conditioning will turn on and the machine will operate. Thus, to ensure continuous service, the utility must size its capacity based on the projected system peak demand plus a margin to provide for contingencies such as forced outages, unexpected severe weather or load forecast error. If a utility were to size its generation capacity to meet average demand, it could not provide continuous service. This is demonstrated in the chart below. The chart depicts a utility that

[31] *Id.* at Exhibit WSS-16.

Why Electric Facilities are Sized to Meet Peak Demand



serves two customer classes (A and B).

Each class uses 2,400 kWh of energy over a 24-hour period. Thus, both classes have an average demand of 100 kW (2,400 kWh ÷ 24 hours). However, Class A has a cyclical load shape while Class B has a flat load shape. Because of its cyclical load shape, Class A's maximum demand is 200 kW. Class B's maximum demand is 100 kW. In order to serve both classes, the utility would require 300 kW (ignoring reserves). Had the utility provided only 200 kW (which is the combined average load of the two classes), it could not have provided reliable service.

Q DO YOU HAVE OTHER CONCERNS WITH THE BIP METHOD?

A Yes. As previously stated, about 34% of LG&E's production fixed costs would be allocated on a pure energy basis. A pure energy allocator assumes that every hour of the year is cost-causative; that is, usage at 2 a.m. in the spring and fall is just as important in determining a utility's base load investment as usage that occurs between 3 and 4 p.m. on a hot summer afternoon or between 8 and 9 p.m. on a cold winter morning.

The reality is, as previously discussed, that the required amount of generation capacity is sized to meet a utility's peak demand. Further, an investment that is built to serve on-peak demand is also available to serve off-peak demand. In other words, off-peak usage is a *bi-product* of on-peak usage. Therefore, BIP is not consistent with cost causation because off-peak usage is merely a *bi-product* of providing generation capacity that meets LG&E's projected peak demand.

In summary, cost causation is primarily a function of peak demand. Thus, a proper cost allocation method should emphasize peak demand. LOLP places more emphasis on peak demand. Therefore, it reflects cost causation.

Summary of CCOSS Results

Q DESPITE THE DIFFERENCES BETWEEN LOLP AND BIP METHODS, ARE THE RESULTS OF THE LOLP COST STUDY DRAMATICALLY DIFFERENT FROM THE RESULTS OF THE BIP COST STUDY?

A No. The table below summarizes the results of the LOLP and BIP CCOSSs. As the table demonstrates, the results are directionally similar; that is,for most of the major customer classes, a class that is above cost under LOLP is also above cost under BIP, and vice versa.

Summary of LG&E's Electric Class Cost-of-Service Study Results at Present Rates

Customer Class	LOLP Method		BIP Method	
	Rate of Return	Subsidy ($000)	Rate of Return	Subsidy ($000)
Residential	2.04%	($57,553)	2.65%	($42,599)
General Service	8.65%	16,869	7.34%	11,926
Power Service Primary	7.03%	748	6.49%	580
Power Service Secondary	9.70%	21,463	8.84%	18,532
Time of Day Primary	5.39%	1,726	4.57%	(1,391)
Time of Day Secondary	11.90%	16,355	11.92%	16,377
Retail Transmission	4.83%	(168)	3.48%	(2,986)
Special Contract #1	2.18%	(645)	1.70%	(797)
Special Contract #2	3.11%	(195)	2.45%	(285)
Lighting Rate RLS & LS	6.01%	1,327	5.39%	605
Lighting Rate LE	17.55%	39	8.01%	16
Lighting Rate TE	10.39%	36	7.62%	21
Total Kentucky Jurisdiction	4.92%	$0	4.92%	$0

A negative amount means that a class is being subsidized by other classes; a positive amount means that a class is subsidizing other classes.

Q **PLEASE EXPLAIN THE TERMS RATE OF RETURN AND SUBSIDY.**

A Rate of return measures the profitability of each customer class. It is derived by dividing net operating income (revenues less allocated operating expenses) by rate base. The subsidy represents the extent that current revenues are above (a positive amount) or below (a negative amount) cost, where cost is defined as income sufficient to earn the system average rate of return. Thus, reducing the subsidies would result in moving rates closer to cost.

Q WHAT DO THE RESULTS OF THE CLASS COST-OF-SERVICE STUDIES DEMONSTRATE?

A The results demonstrate that LG&E's rates are not cost-based. In order to move closer to cost-based rates, the General Service, Power Service Secondary, Power Service Primary, Time of Day Primary, Time of Day Secondary, and Lighting classes should receive below-system average rate increases, while the below-cost classes should receive above-system average rate increases.

However, given that there are disparities between revenues and costs by rate class in both CCOSSs, adopting either the LOLP or the BIP method would not significantly change the class revenue allocation needed to move all rates closer to cost, which is discussed next.

Recommendation

Q WHAT DO YOU RECOMMEND?

A Given the similarity between the two CCOSSs, the Commission need not reach any decision on which CCOSS, LOLP or BIP, should be adopted. However, if the Commission wants to approve a specific CCOSS for use in both allocating base revenues and designing rates, I recommend that the LOLP CCOSS be adopted.

4. CLASS REVENUE ALLOCATION: ELECTRIC

Q. WHAT IS CLASS REVENUE ALLOCATION?

A. Class revenue allocation is the process of determining how any base revenue change the Commission approves should be spread to each customer class a utility serves.

Q. HOW SHOULD ANY CHANGE IN BASE REVENUES APPROVED IN THIS DOCKET BE SPREAD AMONG THE VARIOUS CUSTOMER CLASSES LG&E SERVES?

A. Base revenues should reflect the actual cost of providing service to each customer class as closely as practicable. Regulators sometimes limit the immediate movement to cost based on principles of gradualism, rate administration, and other factors.

Q. PLEASE EXPLAIN THE PRINCIPLE OF GRADUALISM.

A. *Gradualism* is a concept that is applied to prevent a class from receiving an overly-large rate increase. That is, the movement to cost of service should be made gradually rather than all at once because it would result in rate shock to the affected customers.

Q. HOW IS RATE ADMINISTRATION RELATED TO RATE CHANGE?

A. *Rate administration* is a concept that applies when the design of a rate may be tied to the design of other rates to minimize revenue losses when customers migrate from a more expensive to a less expensive rate.

Q. ARE THERE OTHER REASONS TO APPLY COST-OF-SERVICE PRINCIPLES WHEN CHANGING RATES?

A. Yes. The other reasons for adhering to cost-of-service principles are equity, engineering efficiency (cost-minimization), stability and conservation.

Q. WHY ARE COST-BASED RATES EQUITABLE?

A. Rates which primarily reflect cost-of-service considerations are equitable because each customer pays what it actually *costs* the utility to serve the customer – no more and no less. If rates are not based on cost, then some customers must pay part of the cost of providing service to other customers, which is inequitable.

Q. HOW DO COST-BASED RATES PROMOTE ENGINEERING EFFICIENCY?

A. With respect to engineering efficiency, when rates are designed so that demand and energy charges are properly reflected in the rate structure, customers are provided with the proper incentive to minimize their costs, which will, in turn, minimize the costs to the utility.

Q. HOW CAN COST-BASED RATES PROVIDE STABILITY?

A. When rates are closely tied to cost, the utility's earnings are stabilized because changes in customer use patterns result in parallel changes in revenues and expenses.

Q. HOW DO COST-BASED RATES ENCOURAGE CONSERVATION?

A. By providing balanced price signals against which to make consumption decisions, cost-based rates encourage conservation (of both peak day and total usage), which is properly defined as the avoidance of wasteful or inefficient use (not just *less use*). If rates are not based on a CCOSS, then consumption choices are distorted.

LG&E's Proposal

Q. HOW IS LG&E PROPOSING TO ALLOCATE THE PROPOSED BASE REVENUE INCREASE IN THIS PROCEEDING?

A. As previously discussed, LG&E is proposing a $93.6 million overall increase. The $93.6 million is comprised of the following components.

Components of LG&Es Proposed Increase (Dollars in 000)		
Description	**Amount**	**Percent**
Base Rates	$91.720	8.3%
Curtailable Rider	$1,920	-44.3%
Other Revenue	(22)	-0.1%
Total Proposed Increase	$93.618	8.4%

LG&E's proposed base revenue increase is shown in **Exhibit JP-9,** page 1. This measures the increase as a percent of total revenues, including those revenues that are collected under separate adjustment clauses. The adjustment clauses are:

- Fuel Adjustment Clause (FAC).
- Demand-Side Management Cost Recovery Mechanism (DSM).
- Environmental Cost Recovery Surcharge (ECR).
- Off-System Sales Adjustment Clause (OSS).
- Franchise Fee Rider (FF).
- School Tax (ST).
- Home Energy Assistance Program (HEA).

When measured on this basis, LG&E is proposing above-average rate increases to the Residential, Retail Transmission (RTS), and Special Contract #1 rates. As previously discussed, above system-average increases are appropriate for those classes that are currently below cost (*e.g.,* Residential, TODP, RTS, and Special Contracts #1 and #2).

Q. IS ANY OF THE PROPOSED $91.7 MILLION BASE REVENUE INCREASE RELATED TO THE RECOVERY OF FUEL, DSM AND ECR COSTS THAT ARE BEING SEPARATELY RECOVERED?

A. No. LG&E is seeking an increase in base rates, not an increase in non-base rate costs (*e.g.,* FAC, DSM, ECR) that are recovered in separate adjustment clauses. These non-base rate costs are recovered in separate adjustment clauses. Further, base rates also recover 2.725¢ per kWh of embedded fuel charges. The proposed increase has nothing to do with recovering higher fuel costs.

Q IS IT APPROPRIATE TO MEASURE THE IMPACT OF A BASE REVENUE INCREASE INCLUDING REVENUES THAT ARE RECOVERED IN SEPARATE ADJUSTMENT CLAUSES AND EMBEDDED FUEL CHARGES?

A No. Given that the $91.7 million base revenue increase is due entirely to the recovery of higher non-fuel base rate costs, the most appropriate way to measure the proposed increase is relative to the present revenues restated to remove the adjustment clauses and embedded fuel charges. When restated in this manner, LG&E's $91.7 million increase is actually a 14.2% increase in non-fuel base revenues as shown in the table below.

LG&E's Proposed Base Revenue Increase Excluding Embedded Fuel Costs (Dollars in 000)	
Description	**Amount**
Base Revenue Increase	$91,720
Present Base Revenues	$965,204
Embedded Fuel Charges*	$317,366
Non-Fuel Revenues	$647,838
Percent Increase	14.2%
* 2.725¢ per kWh.	

Q HAVE YOU RESTATED LG&E'S PROPOSED INCREASE RELATIVE TO NON-FUEL BASE REVENUES?

A Yes. **Exhibit JP-9**, page 2 restates LG&E's proposed class revenue allocation with all adjustment clauses and embedded fuel charges removed. When measured on this more appropriate basis, it is clear that the Power Service Primary class, which is providing an above system-average rate of return would also receive an above system average increase.

Q HOW DID LG&E DETERMINE ITS CLASS REVENUE ALLOCATION?

A LG&E states that its objective was to eliminate subsidies gradually over time based primarily on the results of the LOLP CCOSS as well as the ratemaking principle of gradualism for its proposed class revenue allocation.[32]

Q HOW DID LG&E APPLY GRADUALISM?

A I can find no evidence demonstrating how LG&E applied gradualism in this case.

[32] Testimony of Robert Steven Seelye at 9-10; Testimony of Robert M. Conroy at 7-9.

For example, LG&E's proposal reducing the Curtailment Service Rider credit by 44% violates gradualism because it would represent a price change that exceeds 1.5 times the system-average increase that LG&E is seeking in this case.

Q WOULD LG&E'S PROPOSED CLASS REVENUE ALLOCATION RESULT IN RATES MOVING CLOSER TO COST?

A No. **Exhibit JP-10** summarizes the LOLP CCOSS results at present and proposed rates. The rate of return is shown in columns 1 and 2, and the subsidies are shown in columns 3 and 4. Column 5 shows the change in the subsidies from present (column 3) to proposed (column 4) rates.

As can be seen, the subsidies at proposed rates for eight of the twelve customer classes would be higher than the corresponding subsidies at present rates; that is, rates would move farther from, rather than closer to cost for the majority of customer classes. Further, LG&E overshot the mark for the Retail Transmission (RTS) class, which would move from slightly below cost at present rates to substantially above cost at proposed rates. Overall, LG&E's proposed class revenue allocation would result in rates moving 47% away from cost.

Recommendation

Q WHAT DO YOU RECOMMEND?

A I recommend spreading the authorized revenue increase in a manner that would reduce each class's subsidy, subject only to limiting the increase to any rate class to 1.5 times the system average increase measured relative to non-fuel base revenues (*i.e.*, excluding adjustment clauses and embedded fuel charges).

Q HAVE YOU DEVELOPED A CLASS REVENUE ALLOCATION THAT MOVES RATES CLOSER TO COST?

A Yes. **Exhibit JP-11** is my recommended class revenue allocation. The starting point for my recommendation was to assign target relative increases by customer class based on the class's rate of return (as shown on **Exhibit JP-10**) as a percentage of the retail rate of return at present rates as follows:

ROR at Present Rates on Exhibit JP-10 As A % of Retail Avg. ROR	% of System Avg. Non-Fuel Increase
90%-110%	100%
75%-89%	125%
<75%	150%
111%-125%	75%
126%-200%	50%
>200%	0%

Thus, classes having rates of return that are ±10% of the system average would receive a system average increase. Classes that are below cost (*i.e.,* earning below-system average rates of return) at present rates would receive progressively higher relative increases depending on whether their rate of return is at or below 75% of the system average. Classes that are above cost (*i.e.,* earning a rate of return above the system average) would receive progressively lower below-average increases depending on whether their rate of return is above 110% and 126% of the system average increase. As Rate LE is earning an excessive return (over 200% of the system average) at present rates it would be inappropriate to increase that rate.

I then adjusted the target increases for the TOD classes so that there would not be any movement away from cost, and the RTS increase was capped so that it would move to (rather than above) cost.

Q HAVE YOU CONFIRMED THAT THE CLASS REVENUE ALLOCATION SHOWN IN EXHIBIT JP-11 WOULD RESULT IN MOVING ALL RATES, EXCEPT FOR RATE TODP, CLOSER TO COST?

A Yes. **Exhibit JP-12** shows the LOLP CCOSS results at recommended rates. As can be seen, with one exception, the subsidies would be lower. Overall, rates would move 20% closer to cost. This is in stark contrast to LG&E's proposed class revenue allocation, which would be a huge step backward (*i.e.,* overall rates would move 47% away from cost).

Q IF THE COMMISSION AUTHORIZES A LOWER INCREASE FOR LG&E, HOW SHOULD THAT LOWER INCREASE BE SPREAD AMONG THE CUSTOMER CLASSES?

A My recommendation would be to scale down the increases in proportion to the overall base revenue increase that the Commission ultimately awards. For example, if LG&E receives a $45.9 million base revenue increase (which is 50% of its proposed increase, excluding the increases in the Curtailment Rider and other revenues), then the increases shown in **Exhibit JP-11** should be reduced by 50%.

5. CLASS COST-OF-SERVICE STUDY: GAS

Q HAVE YOU REVIEWED THE CLASS COST-OF-SERVICE STUDY FOR NATURAL GAS DELIVERY SERVICE FILED BY LG&E IN THIS PROCEEDING?

A Yes. Based on my review, the structure and methodology used by LG&E generally comport with accepted practice.

Q WHAT PROCEDURES ARE USED IN A CLASS COST-OF-SERVICE STUDY FOR NATURAL GAS DELIVERY SERVICE?

A The basic procedure for conducting a Gas CCOSS is similar to the procedure used in an Electric CCOSS. First, we identify the different types of costs (functionalization), determine their primary causative factors (classification), and then apportion each item of cost among the various rate classes (allocation). Adding up the individual pieces gives the total cost for each class.

Identifying the utility's different levels of operation is a process referred to as functionalization. A local distribution company's (LDC's) investments and expenses are separated into transmission, distribution, and other functions. To a large extent, this is done in accordance with the Uniform System of Accounts developed by the Federal Energy Regulatory Commission (FERC).

Once costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as classification. For an LDC, costs are classified as demand or capacity costs, energy or commodity costs, and customer costs. As described in the NARUC Gas Distribution Rate Design Manual:

> Demand or capacity costs vary with the quantity or size of plant equipment. They are related to maximum system requirements which the system is designed to serve during short intervals and do not

> directly vary with the number of customers or their annual usage. Included in these costs are: the capital costs associated with production, transmission and storage plant and their related expenses; the demand cost of gas; and most of the capital costs and expenses associated with that part of distribution plant not allocated to customer costs, such as the costs associated with distribution mains in excess of the minimum size.
>
> Energy or commodity costs are those which vary with the quantity of gas produced or purchased. They are largely made up of the commodity portion of purchased gas cost and the cost of feedstock, catalyst, fuel, and other variable expenses used in the production of gas from a manufactured or synthetic gas (SNG) plant. Energy or commodity costs increase or decrease as more or less gas is consumed.
>
> Customer costs are those operating capital costs found to vary directly with the number of customers served rather than with the amount of utility service supplied. They include the expenses of metering, reading, billing, collecting, and accounting, as well as those costs associated with the capital investment in metering equipment and in customers' service connections. [This includes a portion of the distribution system, such as mains.][33]

Finally, certain costs vary with revenue and include, but are not limited to revenue-related taxes. These costs are termed revenue-related.

Each functionalized and classified cost must then be allocated to the various customer classes. This is accomplished by developing allocation factors that reflect the percentage of the total cost that should be paid by each class. The allocation factors should reflect cost causation; that is, the degree to which each class caused the utility to incur the cost.

[33] National Association of Regulatory Utility Commissioners (NARUC), *Gas Distribution Rate Design Manual* at 22-24 (June 1989).

Q WHAT KEY PRINCIPLES ARE RECOGNIZED IN A CLASS COST-OF-SERVICE STUDY FOR NATURAL GAS SERVICE?

A A properly conducted Gas CCOSS recognizes two key cost-causation principles. First, not all gas customers purchase gas supplied by an LDC. Some customers purchase and transport their own gas to the city gate. Thus, the LDC does not incur purchased gas and other related costs to serve a transportation customer. Second, since cost causation is also related to how natural gas is used, both the timing and rate of gas consumption (*i.e*., demand) are critical. Consistent with the obligation to serve and to ensure reliability, the LDC must purchase sufficient gas supply to meet the maximum needs of its sales customers. The LDC must also construct the required distribution mains and other facilities to meet the contribution to the maximum demand that can potentially be placed on the system by the classes or by the customers within the classes.

<u>Summary of Gas CCOSS Results</u>

Q WHAT ARE THE RESULTS OF LG&E'S CLASS COST-OF-SERVICE STUDY FOR NATURAL GAS SERVICE?

A The results of LG&E's Gas CCOSS are summarized in the table below. These are the same measures as previously discussed in connection with LG&E's Electric CCOSS.

Summary of LG&E's Gas Class Cost-of-Service Study Results At Present Rates		
Customer Class	**Rate of Return**	**Subsidy ($Millions)**
Residential Service Rate RGS	5.08%	($7,818)
Commercial Service Rate CGS	7.32%	3,529
Industrial Service Rate IGS	21.31%	2,634
As Available Gas Service Rate AAGS	30.69%	315
Firm Transportation Service Rate FT	11.00%	1,340
Total Retail	6.00%	$0

Q WHAT DO THE RESULTS OF LG&E'S GAS CLASS COST-OF-SERVICE STUDY DEMONSTRATE?

A The Gas CCOSS results demonstrate that LG&E's gas delivery rates diverge substantially from cost. As the above table demonstrates:

- Three classes are providing double-digit returns. This is significant because LG&E is seeking a proposed rate of return of only 7.19%.
- Residential delivery rates are being heavily subsidized by the other classes. Approximately 6¢ of every dollar of delivery revenue represents a subsidy by non-Residential delivery customers whose current rates are already generating more than adequate revenues than their allocated costs, even at LG&E's proposed revenue requirement.

Thus, in order to move rates closer to cost, residential delivery rates should receive above-average delivery rate increases, while all other classes should receive either substantially below-average or no increase in their delivery rates.

6. CLASS REVENUE ALLOCATION: GAS

Q DO THE SAME RATEMAKING PRINCIPLES THAT YOU DESCRIBE FOR ELECTRIC CLASS REVENUE ALLOCATION ALSO APPLY TO NATURAL GAS DELIVERY SERVICE?

A Yes.

LG&E Proposal

Q HOW IS LG&E PROPOSING TO SPREAD THE PROPOSED GAS DELIVERY REVENUE INCREASE?

A LG&E's proposed class revenue allocation is shown in **Exhibit JP-13**. As can be seen, LG&E is proposing to increase delivery rates for all but two customer classes: Industrial Gas Service (IGS) and As-Available Gas Service (AAGS). The IGS class would receive no increase, while the AAGS rates would be substantially reduced. For the remaining classes, the proposed increase would range from 2.7% for Firm Transportation (FT) to 10.2% for the Residential class. These compare to an overall 9.3% system-wide increase.

Q IS LG&E'S PROPOSED CLASS REVENUE ALLOCATION REASONABLE?

A No. LG&E says that it is proposing to spread the proposed delivery rate increase based on the results of its CCOSS. Although I agree in concept with LG&E's proposal, LG&E's proposed class revenue allocation would barely move rates closer to cost. This is shown in **Exhibit JP-14**. As can be seen, rates overall would move only 5% closer to cost. At this pace, assuming that LG&E were to file rate cases every three years, it would not achieve cost-based rates for at least 40 years.

<u>Recommendation</u>

Q WHAT DO YOU RECOMMEND?

A The results of LG&E's Gas CCOSS are far more disparate than the Electric CCOSS. All customer classes, except Residential, are paying rates that are not only above cost at present rates, they already exceed the rate of return that LG&E is seeking to earn in this case. Accordingly, I recommend no increase in gas delivery rates to the non-Residential classes. The resulting class revenue allocation is shown in **Exhibit JP-15**.

Exhibit JP-16 shows that based on the class revenue allocation presented in **Exhibit JP-15**, all classes would move closer to cost. Overall, Gas delivery rates would be 74% closer to cost.

Q IF THE COMMISSION AUTHORIZES A LOWER GAS REVENUE INCREASE FOR LG&E, HOW SHOULD THAT LOWER INCREASE BE SPREAD AMONG THE CUSTOMER CLASSES?

A I recommend 50% of any reduction in LG&E's overall increase be spread to reduce non-Residential delivery rates. As previously indicated, the non-Residential classes are currently providing rates of return in excess of the rate of return that LG&E is seeking in this case. If LG&E is awarded a lower rate of return, reducing the rates of return of the non-Residential classes (by lowering their delivery rates) would ensure some movement to cost even at a lower revenue deficiency.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES AND FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY	))))	**CASE NO. 2016-00371**

AFFIDAVIT OF JEFFRY POLLOCK

State of Missouri)
) **SS**
County of St. Louis)

Jeffry Pollock, being first duly sworn, on his oath states:

1. My name is Jeffry Pollock. I am President of J. Pollock, Incorporated, 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141. We have been retained by Louisville/Jefferson Metro Government to testify in this proceeding on its behalf;

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony, Exhibits and Appendices A and B, which have been prepared in written form for introduction into evidence in the Public Service Commission of Commonwealth of Kentucky, Case No. 2016-00371; and,

3. I hereby swear and affirm that my answers contained in the testimony are true and correct.

Jeffry Pollock
Jeffry Pollock

Subscribed and sworn to before me this 3rd day of March 2017.

KITTY TURNER
Notary Public - Notary Seal
State of Missouri
Commissioned for Lincoln County
My Commission Expires: April 25, 2019
Commission Number: 15390610

K. Tu
Kitty Turner, Notary Public
Commission #: 15390610

My Commission expires on April 25, 2019.

APPENDIX A

<u>Qualifications of Jeffry Pollock</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock. My business mailing address is 12647 Olive Blvd., Suite 585, St. Louis, Missouri 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 Master's Degree 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. Recent engagements have included advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing requests for proposals (RFPs), evaluating RFP responses and contract negotiation. I was also responsible for developing and presenting 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, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, 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 Board of Directors of the South Carolina Public Service Authority (a.k.a. Santee Cooper), the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

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.

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160402	SHARYLAND UTILITIES, L.P.	Texas Industrial Energy Consumers	45414	Direct	TX	Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; TCRF Allocation Factors; McAllen Division Deferrals	2/28/2017
140105	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	46025	Direct	TX	Long-Term Purchased Power Agreements	12/12/2016
151101	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Surrebuttal	MN	Settlement, Cost-of-Service Study, Class Revenue Allocation, Interruptible Rates, Renew-A-Source	10/18/2016
151101	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Rebutal	MN	Class Cost-of-Service Study, Class Revenue Allocation	9/23/2016
131001	VICTORY ELECTRIC COOPERATION ASSOCIATION, INC.	Westerrn Kansas Industrial Electric Consumers	16-VICE-494-TAR	Surrebuttal	KS	Formula-Based Rate Plan	9/22/2016
160704	NATIONAL FUEL GAS DISTRIBUTION CORPORATION	Multiple Intervenors	16-G-0257	Rebuttal	NY	Embedded Class Cost of Service; Class Revenue Allocation; Rate Design	9/16/2016
140105	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	45524	Cross-Rebuttal	TX	Class Cost-of-Service Study;	9/7/2016
160301	METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Surrebuttal	PA	Post-Test Year Sales Adjustment; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	8/31/2016
131001	VICTORY ELECTRIC COOPERATION ASSOCIATION, INC.	Westerrn Kansas Industrial Electric Consumers	16-VICE-494-TAR	Direct	KS	Formula-Based Rate Plan	8/30/2016
131001	WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC.	Westerrn Kansas Industrial Electric Consumers	16-WSTE-496-TAR	Direct	KS	Formula-Based Rate Plan and Debt Service Payments	8/30/2016
160704	NATIONAL FUEL GAS DISTRIBUTION CORPORATION	Multiple Intervenors	16-G-0257	Direct	NY	Embedded Class Cost of Service; Class Revenue Allocation; Rate Design	8/26/2016
160301	METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Rebuttal	PA	Class Cost-of-Service; Class Revenue Allocation	8/17/2016
140105	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	45524	Direct	TX	Revenue Requirement; Class Cost-of-Service; Revenue Allocation; Rate Design	8/16/2016
160301	METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER	MEIUG, PICA and WPPII	2016-2537349 2016-2537352 2016-2537359	Direct	PA	Post-Test Year Sales Adjustment; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	7/22/2016

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160101	FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	160021	DIrect	FL	Multi-Year Rate Plan, Construction Work in Progress; Cost of Capital; Class Revenue Allocation; Class Cost-of-Service Study; Rate Design	7/7/2016
160103	CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Supplemental	AR	Support for Settlement Stipulation	7/1/2016
160503	MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2016-0001	Direct	IA	Application of Advanced Ratemaking Principles to Wind XI	6/21/2016
151101	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Direct	MN	Class Cost-of-Service Study, Class Revenue Allocation, Multi-Year Rate Plan, Rate Design	6/14/2016
160103	CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Surrebuttal	AR	Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, LCS-1 Rate Design	6/7/2016
150504	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	15-00296-UT	Direct	NM	Support of Stipulation	5/13/2016
160102	CHEYENNE LIGHT, FUEL AND POWER COMPANY	Dyno Nobel, Inc. and HollyFrontier Cheyenne Refining LLC	20003-146-ET-15	Cross	WY	Large Power Contract Service Tariff	4/15/2016
160103	CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Direct	AR	Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, Act 725, Formula Rate Plan	4/14/2016
160102	CHEYENNE LIGHT, FUEL AND POWER COMPANY	Dyno Nobel, Inc. and HollyFrontier Cheyenne Refining LLC	20003-146-ET-15	Direct	WY	Large Power Contract Service Tariff	3/18/2016
150803	ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA POWER, LLC	Occidental Chemical Corporation	U-33770	Cross-Answering	LA	Approval to Construct St. Charles Power Station	2/26/2016
151102	NORTHERN INDIANA PUBLIC SERVICE COMPANY	NLMK-Indiana	44688	Cross-Answering	IN	Cost-of-Service Study, Rider 775	2/16/2016
150803	ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA POWER, LLC	Occidental Chemical Corporation	U-33770	Direct	LA	Approval to Construct St. Charles Power Station	1/21/2016
150701	ELECTRIC TRANSMISSION TEXAS LLC	Freeport-McMoRan Copper & Gold, Inc.	44941	Cross-Rebuttal	TX	Class Cost-of-Service Study, Class Revenue Allocation; Rate Design	1/15/2016
150503	ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Supplemental	AR	Support for Settlement Stipulation	12/31/2015
150701	ELECTRIC TRANSMISSION TEXAS LLC	Freeport-McMoRan Copper & Gold, Inc.	44941	Direct	TX	Class Cost-of-Service Study, Class Revenue Allocation; Rate Design	12/11/2015

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150503	ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Surrebuttal	AR	Post-Test-Year Additions; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Riders; Formula Rate Plan	11/24/2015
131001	MID-KANSAS ELECTRIC COMPANY, LLC, PRAIRIE LAND ELECTRIC COOPERATIVE, INC., SOUTHERN PIONEER ELECTRIC COMPANY, THE VICTORY ELECTRIC COOPERATIVE ASSOCIATION, INC., AND WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-MKEE-023	Direct	KS	Formula Rate Plan for Distribution Utility	11/17/2015
130901	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	45084	Direct	TX	Transmission Cost Recovery Factor Revenue Increase.	11/17/2015
140103	GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Assocation of Manufacturers	39638	Direct	GA	Natural Gas Price Assumptions, IFR Mechanism, Seasonal FCR-24 Rates, Imputed Capacity	11/4/2015
150801	NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	15-E-0283 15-G-0284 15-E-0285 15-G-0286	Rebuttal	NY	Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation	10/13/2015
150503	ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Direct	AR	Post-Test-Year Additions; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Riders; Formula Rate Plan	9/29/2015
150801	NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	15-E-0283 15-G-0284 15-E-0285 15-G-0286	Direct	NY	Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation, Electric Rate Design	9/15/2015
130602	SHARYLAND UTILITIES	Texas Industrial Energy Consumers	44620	Cross-Rebuttal	TX	Transmission Cost Recovery Factor Class Allocation Factors.	9/8/2015
150503	ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	14-118	Surrebuttal	AR	Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery	8/21/2015
130602	SHARYLAND UTILITIES	Texas Industrial Energy Consumers	44620	Direct	TX	Transmission Cost Recovery Factor Class Allocation Factors	8/7/2015
150303	PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Surrebuttal	PA	Class Cost-of-Service, Capacity Reservation Rider	8/4/2015
130701	WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	15-WSEE-115-RTS	Cross-Answering	KS	Class Cost-of-Service Study, Revenue Allocation	7/22/2015
150303	PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Rebuttal	PA	Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider, Revenue Deoupling	7/21/2015
150504	SOUTHWEST ERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd.	15-00083	Direct	NM	Long-Term Purchased Power Agreements	7/10/2015

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150503	ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-014	Surrebuttal	AR	Solar Power Purchase Agreement	7/10/2015
130701	WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	15-WSEE-115-RTS	Direct	KS	Class Cost-of-Service and Electric Distrbution Grid Resiliency Program	7/9/2015
130901	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	43958	Supplemental DIrect	TX	Certificiate of Need for Union Power Station Power Block 1	7/7/2015
150503	ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	14-118	Direct	AR	Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery	7/2/2015
150303	PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Direct	PA	Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider	6/23/2015
150503	ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-014-U	Direct	AR	Solar Power Purchase Agreement	6/19/2015
140201	FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	150075	Direct	FL	Cedar Bay Power Purchase Agreement	6/8/2015
140105	SOUTHWEST ERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Cross-Rebuttal	TX	Class Cost of Service Study; Class Revenue Allocation	6/8/2015
140201	FLORIDA POWER AND LIGHT COMPANY, DUKE ENERGY FLORIDA, GULF POWER COMPANY, TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	140226	Surrebuttal	FL	Opt-Out Provision	5/20/2015
140105	SOUTHWEST ERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Direct	TX	Post-Test Year Adjustments; Weather Normalization	5/15/2015
140105	SOUTHWEST ERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Direct	TX	Class Cost of Service Study; Class Revenue Allocation	5/15/2015
130901	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	43958	Direct	TX	Certificiate of Need for Union Power Station Power Block 1	4/29/2015
140404	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	42370	Cross-Rebuttal	TX	Allocation and recovery of Municipal Rate Case Expenses and the proposed Rate-Case-Expense Surcharge Tariff.	1/27/2015
140904	WEST PENN POWER COMPANY	West Penn Power Industrial Intervenors	2014-2428742	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015
140903	PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015

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140902	METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015
140904	WEST PENN POWER COMPANY	West Penn Power Industrial Intervenors	2014-2428742	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	12/18/2014
140903	PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	12/18/2014
140902	METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	12/18/2014
140804	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Healthcare Electric Coordinating Council	14AL-0660E	Cross	CO	Clean Air Clean Jobs Act Rider; Transmission Cost Adjustment	12/17/2014
140904	WEST PENN POWER COMPANY	West Penn Power Industrial Intervenors	2014-2428742	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider	11/24/2014
140903	PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider	11/24/2014
140902	METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider	11/24/2014
140905	CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	14-E-0318 / 14-G-0319	Direct	NY	Class Cost-of-Service Study; Class Revenue Allocation (Electric)	11/21/2014
140804	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Healthcare Electric Coordinating Council	14AL-0660E	Direct	CO	Clean Air Clean Jobs Act Rider; Electric Commodity Adjustment Incentive Mechanism	11/7/2014
140201	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	140001-E	Direct	FL	Cost-Effectiveness and Policy Issues Surrounding the Investment in Working Gas Production Facilities	9/22/2014
140401	ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Surrebuttal	WY	Class Cost-of-Service, Rule 12 (Line Extension Policy)	9/19/2014

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140805	INDIANA MICHIGAN POWER COMPANY	I&M Industrial Group	44511	Direct	IN	Clean Energy Solar Pilot Project, Solar Power Rider and Green Power Rider	9/17/2014
140401	ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Cross	WY	Class Cost-of-Service Study; Rule 12 Line Extension	9/5/2014
140201	VARIOUS UTILITIES	Florida Industrial Power Users Group	140002-EI	Direct	FL	Energy Efficiency Cost Recovery Opt-Out Provision	9/5/2014
131002	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Surrebuttal	MN	Nuclear Depreciation Expense, Monticello EPU/LCM Project, Class Cost-of-Service Study, Class Revenue Allocation, Fuel Clause Rider Reform, Rate Design	8/4/2014
140401	ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Direct	WY	Class Cost-of-Service Study, Rule 12 Line Extension	7/25/2014
140601	DUKE ENERGY FLORIDA	NRG Florida, LP	140111 and 140110	Direct	FL	Cost-Effectiveness of Proposed Self Build Generating Projects	7/14/2014
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

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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
130501	MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Surrebuttal	IA	Class Cost-of-Service Study; Class Revenue Allocation; Depreciation Surplus	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
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
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
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

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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 Excemption 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 Subsidiary	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
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

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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
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

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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
100303	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	10-E-0050	Direct	NY	Multi-Year Rate Plan, Cost Allocation, Revenue Allocation, Reconciliation Mechanisms, Rate Design	7/14/2010
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

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90403	VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00019	Direct	VA	Standby rate design; dynamic pricing	11/9/2009
90403	VIRGINIA ELECTRIC AND POWER COMPANY	MWV	PUE-2009-00019	Direct	VA	Base Rate Case	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
81201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Surrebuttal	MN	Cost allocation, revenue allocation, rate design	5/27/2009
80805	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	36025	Direct	TX	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

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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
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
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
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
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 Cross Rebuttal	TX	Certificate of Convenience and Necessity	5/21/2008
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
60303	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	26794	Direct	GA	Fuel Cost Recovery	4/15/2008
41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	35038	Rebuttal	TX	Over $5 Billion Compliance Filing	4/14/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Eligible Fuel Expense	4/11/2008

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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
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	3/24/2008
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
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
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Rebuttal Remand	TX	Interest rate on stranded cost reconciliation	6/15/2007
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	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

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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
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	32758	Direct	TX	Rider CTC design and cost recovery	08/24/06
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
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
60101	COLQUITT EMC	ERCO Worldwide	23549-U	Direct	GA	Service Territory Transfer	08/10/06
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

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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
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
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

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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
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

Appendix B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
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
6713	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	16995	Cross-Rebuttal	TX	IRR	1/1/1998
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

Appendix B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
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
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

LOUISVILLE GAS AND ELECTRIC COMPANY
Derivation of Surplus Depreciation Reserve
At December 31, 2015
(Amounts in $000)

		Electric Plant			Kentucky Jurisdiction					
							Surplus Reserve			
Line	Function	Theoretical Reserve	Actual Reserve	Surplus Reserve	Theoretical Reserve	Actual Reserve	Amount	Excluding ECR & DSM	Proposed Accrual	Years
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Steam Production**	$787,072	$846,861	$59,789	$787,072	$846,861	$59,789	$56,766	$57,287	1.0
2	**Hydro Production**	14,394	13,773	(622)	14,394	13,773	(622)	(622)	4,021	0.2
3	**Other Production**	120,972	107,258	(13,715)	120,972	107,258	(13,715)	(13,715)	16,828	0.8
4	**Total Production**	922,439	967,891	45,453	922,439	967,891	45,453	42,430	78,137	0.5
5	**Transmission**	132,621	150,031	17,411	132,621	150,031	17,411	17,411	9,644	1.8
6	**Distribution**	451,042	491,593	40,551	451,042	491,593	40,551	40,551	37,359	1.1
7	**General**	6,968	7,357	390	6,968	7,357	390	382	598	0.6
8	**Common**	85,555	96,982	11,427	85,555	96,982	11,427	11,427	19,839	0.6
9	**Total**	**$1,598,624**	**$1,713,855**	**$115,231**	**$1,598,624**	**$1,713,855**	**$115,231**	**$112,200**	**$145,576**	0.8
10	**Steam Production and Distribution Total**	**$1,238,114**	**$1,338,454**	**$100,340**	**$1,238,114**	**$1,338,454**	**$100,340**	**$97,317**	**$94,646**	1.0

Source: Response to KIUC 1-1; Exhibit JJS-LGE-1; Schedule B 3.2 F.

LOUISVILLE GAS AND ELECTRIC COMPANY
Derivation of Surplus Depreciation Reserve
At December 31, 2015
(Amounts in $000)

		Gas Plant				
Line	Function	Theoretical Reserve	Actual Reserve	Surplus Reserve	Proposed Accrual	Years
		(1)	(2)	(3)	(4)	(5)
1	**Storage**	$31,265	$36,890	$5,625	$3,598	1.6
2	**Transmission**	10,880	11,274	394	1,087	0.4
3	**Distribution**	219,608	236,085	16,478	25,189	0.7
4	**General**	4,844	5,562	718	514	1.4
5	**Common**	36,666	41,564	4,897	8,504	0.6
6	**Total**	**$303,263**	**$331,375**	**$28,112**	**$38,891**	0.7
7	**Storage, Distribution and Common Total**	**$287,539**	**$314,539**	**$27,000**	**$37,291**	0.7

Source: Response to KIUC 1-1; Exhibit JJS-LGE-1, Schedule B-3.2 F Gas.

LOUISVILLE GAS AND ELECTRIC COMPANY
Derivation of Surplus Depreciation Reserve Amortization
At December 31, 2015
(Amounts in $000)

		Electric Plant			Kentucky Jurisdiction				
							Surplus Reserve		Average
Line	Function	Theoretical Reserve	Actual Reserve	Surplus Reserve	Theoretical Reserve	Actual Reserve	Amount	Excluding ECR & DSM	Remaining Life
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Steam Production**	$787,072	$846,861	$59,789	$787,072	$846,861	$59,789	$56,766	23.2
2	**Distribution**	451,042	491,593	40,551	451,042	491,593	40,551	40,551	39.3
3	**Total**	**$1,238,114**	**$1,338,454**	**$100,340**	**$1,238,114**	**$1,338,454**	**$100,340**	**$97,317**	**28.4**
4	Amortization Period (Years)							5	
5	**Annual Amortization**							**$19,463**	

Source: Response to KIUC 1-1; Exhibit JJS-LGE-1; Schedule B3.2 F.

LOUISVILLE GAS AND ELECTRIC COMPANY
Derivation of Surplus Depreciation Reserve
At December 31, 2015
(Amounts in $000)

		Gas Plant			Average
Line	Function	Theoretical Reserve	Actual Reserve	Surplus Reserve	Remaining Life
		(1)	(2)	(3)	(4)
1	**Storage**	$31,265	$36,890	$5,625	39.9
2	**Distribution**	219,608	236,085	16,478	38.5
3	**Common**	$36,666	$41,564	$4,897	5.6
4	**Total**	**$287,539**	**$314,539**	**$27,000**	**36.1**
5	Amortization Period (Years)			5	
6	**Annual Amortization**			**$5,400**	

Source: Response to KIUC 1-1; Exhibit JJS-LGE-1, Schedule B-3.2 F Gas.

LOUISVILLE GAS AND ELECTRIC COMPANY

Revised Depreciation Accruals Assuming a Five-Year Amortization of the Surplus Depreciation Reserve at December 31, 2015

(Amounts in $000)

		Electric Plant Annual Accruals*			Kentucky Jurisdiction Annual Accruals		
Line	Function	Theoretical Reserve	Actual Reserve	Surplus Reserve	Theoretical Reserve	Actual Reserve	Surplus Reserve
		(1)	(2)	(3)	(4)	(5)	(6)
1	**Steam Production**	$59,541	$57,287	$2,254	$59,541	$57,287	$2,254
2	**Distribution**	39,322	37,359	1,963	39,322	37,359	1,963
3	**Total**	**$98,863**	**$94,646**	**$4,217**	**$98,863**	**$94,646**	**$4,217**

Source: Schedule B-3.2 F, Response to KIUC 1-1
* - Does not include accruals associated with ECR and DSM investment.

LOUISVILLE GAS AND ELECTRIC COMPANY

Revised Accrual Rates Assuming an Five-Year Amortization of the Surplus Depreciation Reserve at June 30, 2018

(Amounts in $000)

		Gas Plant Annual Accruals		
Line	**Function**	**Theoretical Reserve**	**Actual Reserve**	**Surplus Reserve**
		(1)	(2)	(3)
1	**Storage**	$3,813	$3,598	$215
2	**Distribution**	25,548	25,189	359
3	**Common**	$8,459	$8,504	($45)
4	**Total**	$37,820	$37,291	$530

Source: Schedule B-3.2 F, Response to KIUC 1-1.

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment to Electric Revenue Requirement Assuming
a Five-Year Amortization of the Surplus Electric Depreciation Reserve
Forecast Test Year Ending June 30, 2018
(Amounts in $000)

Line	Description	Amount	Source
		(1)	(2)
1	Surplus Depreciation Reserve	$97,317	Exhibit JP-2, Page 1, Col. 7, Line 3
2	Amortization Period (Years)	5	
3	Increase in Electric Net Plant	$19,463	Line 1 ÷ Line 2
4	Proposed Rate of Return	7.243%	Schedule A
5	Revenue Requirement Conversion Factor	1.64093	Schedule A
6	Impact of Increase in Net Plant	$2,313	Line 3 x Line 4 x Line 5
7	Adjustment to Depreciation Rates	$4,217	Exhibit JP-3, Page 1, Col. 6, Line 3
8	Net Impact on Electric Revenue Requirements	($12,933)	Line 6 + Line 7 - Line 3

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjustment to Gas Revenue Requirement Assuming
a Five-Year Amortization of the Surplus Gas Depreciation Reserve
Forecast Test Year Ending June 30, 2018
(Amounts in $000)

Line	Description	Amount	Source
		(1)	(2)
1	Surplus Reserve	$27,000	Exhibit JP-2, Page 2, Col. 3, Line 4
2	Amortization Period (Years)	5	
3	Increase in Gas Net Plant	$5,400	Line 1 ÷ Line 2
4	Proposed Rate of Return	7.243%	Schedule A
5	Revenue Requirement Conversion Factor	1.64093	Schedule A
6	Impact of Increase in Net Plant	$642	Line 3 x Line 4 x Line 5
7	Adjustment to Depreciation Rates	$530	Exhibit JP-3, Page 2, Col. 3, Line 4
8	Net Impact on Gas Revenue Requirements	($4,229)	Line 6 + Line 7 - Line 3

ILLUSTRATION SHOWING THE IMPACT OF AMORTIZING A DEPRECIATION SURPLUS

Line	Place New Investment In Service	
1	Investment	$100.0
2	Life Span (Years)	20
3	Depreciation Expense	$5.0

Line	Year	Depreciation Expense
4	1	$5.0
5	2	$5.0
6	3	$5.0
7	4	$5.0
8	5	$5.0
9	6	$5.0
10	7	$5.0
11	8	$5.0
12	9	$5.0
13	10	$5.0
14	**Total Years 1-10**	**$50.0**

ILLUSTRATION SHOWING THE IMPACT OF AMORTIZING A DEPRECIATION SURPLUS

Line	10-Year Life Extension in Year 10	
1	Theoretical Reserve	$33.3
2	Book Reserve	$50.0
3	Depreciation Surplus	$16.7

ILLUSTRATION SHOWING THE IMPACT OF AMORTIZING A DEPRECIATION SURPLUS

Line	Amortize Surplus Over 5 Years	
	Year	**Depreciation Expense**
1	Years 11-15	$0.0
2	Years 16-30	$3.3
3	11	$0.0
4	12	$0.0
5	13	$0.0
6	14	$0.0
7	15	$0.0
8	16	$3.3
9	17	$3.3
10	18	$3.3
11	19	$3.3
12	20	$3.3
13	21	$3.3
14	22	$3.3
15	23	$3.3
16	24	$3.3
17	25	$3.3
18	26	$3.3
19	27	$3.3
20	28	$3.3
21	29	$3.3
22	30	$3.3
23	**Total Years 11-30**	$50.0
24	**Total Years 1-10**	$50.0
25	**Grand Total**	$100.0
	Costs Paid By Past/Future Customers	
26	Years 1-15	$50.0
27	Years 16-30	$50.0
28	**Grand Total**	$100.0

ILLUSTRATION SHOWING THE IMPACT OF AMORTIZING A DEPRECIATION SURPLUS

Line	Use Remaining Life Method (per MidAmerican)	
1	Remaining Investment	$50.0
2	Life Span	20
3	Depreciation Expense	$2.5
	Year	**Depreciation Expense**
4	11	$2.5
5	12	$2.5
6	13	$2.5
7	14	$2.5
8	15	$2.5
9	16	$2.5
10	17	$2.5
11	18	$2.5
12	19	$2.5
13	20	$2.5
14	21	$2.5
15	22	$2.5
16	23	$2.5
17	24	$2.5
18	25	$2.5
19	26	$2.5
20	27	$2.5
21	28	$2.5
22	29	$2.5
23	30	$2.5
24	**Total Years 11-30**	$50.0
	Costs Paid By Past/Future Customers	
25	Years 1-15	$62.5
26	Years 16-30	$37.5
27	**Grand Total**	$100.0

LOUISVILLE GAS AND ELECTRIC COMPANY
Adjustment to Normalize Incentive Compensation Expense
Forecast Test Year Ending June 30, 2018

Line	Incentive Award	2015	2016	Base Year	Test Year	Test Year Versus Base Year
		(1)	(2)	(3)	(4)	(5)
1	Net Income	$6,169,285	$3,155,809	$2,475,210	$0	
2	Cost Control	0	0	196,134	1,509,271	769.5%
3	Customer Reliability	0	0	196,134	1,509,271	769.5%
4	Customer Satisfaction	1,683,396	1,720,441	1,619,281	1,509,271	93.2%
5	Corporate Safety	0	1,617,665	1,522,548	1,509,271	99.1%
6	Individual/Team Effectiveness	3,801,601	4,001,026	3,765,770	4,829,668	128.3%
7	Total Expense	$11,654,282	$10,494,941	$9,775,077	$10,866,752	11.2%
8	Expense Excluding Net Income	$5,484,997	$7,339,132	$7,299,867	$10,866,752	48.9%
9	Projected Test-Year Wage Increase				[redacted]	
10	Adjusted Expense	Col. 3, Line 8 * (1+Col. 4 Line.9)				
11	Adjustment to LG&E Proposed Expense					

Sources:

Response to KIUC-1 Question 19.

Attachment to Response to HS PSC -1 Question 36 Page 1.

Exhibit JP-7

LOUISVILLE GAS AND ELECTRIC COMPANY
Adjustment to Cash Working Capital
Forecast Test Year Ending June 30, 2018
(Dollar Amounts in $000)

		Kentucky Jurisdiction		
Line	Description	Proposed	Adjusted	Difference
		(1)	(2)	(3)=(2)-(1)
1	Operating and Maintenance Expense	$673,347	$673,347	
	Less:			
2	555 - Electric Power Purchased	56,992	56,992	
3	501 - ECR Steam Fuel Exp Recoverable	259		
4	502 - ECR Boiler Expense	670	670	
5	506 - ECR Environmental Expense	5,521	5,521	
6	512 - ECR Boiler-Environmental	3,163	3,163	
7	501 - Fuel - Steam		251,875	
8	547 - Fuel - Other		57,318	
9	O&M Less Purchase Power, ECR and Fuel Expense	$606,742	$297,808	
10	**Cash Working Capital (12.5%)**	**$75,843**	**$37,226**	**($38,617)**
11	Pretax Rate of Return (See Below)			10.74%
12	**Revenue Requirement Impact**			**($4,147)**

Source Response to PSC 1-54, Schedule A, Schedule B-5.2, Schedule J-1.1.

Pretax Rate of Return Calculation	**Capital Structure**	**Cost of Capital**	**Rate of Return**	**Tax Multiplier**	**Pretax Rate of Return**
Long Term Debt	42.91%	4.12%	1.77%		1.77%
Short Term Debt	3.82%	0.72%	0.03%		0.03%
Common Equity	53.27%	10.23%	5.45%	1.640935	8.94%
Total			7.24%		10.74%

LOUISVILLE GAS & ELECTRIC COMPANY
AMS Deployment Cost-Benefit Analysis: Electric

Line	Year	Capital Costs	O&M Costs	Meter Retirement	Benefits	Total Net Benefits
		(1)	(2)	(3)	(4)	(5)
1	2016	$0.3	$0.0	$0.0	$0.0	$0.3
2	2017	35.3	2.3	0.0	(0.4)	37.3
3	2018	35.6	2.3	0.0	(1.5)	36.4
4	2019	34.1	2.9	2.4	(13.2)	26.1
5	2020	1.2	1.5	4.7	(13.2)	(5.8)
6	2021	-	1.8	4.7	(13.2)	(6.7)
7	2022	-	1.8	4.7	(13.4)	(6.9)
8	2023	-	1.9	4.7	(14.0)	(7.5)
9	2024	2.2	1.9	1.6	(14.2)	(8.5)
10	2025	-	2.0	0.4	(14.6)	(12.3)
11	2026	-	2.0		(15.1)	(13.1)
12	2027	-	2.1		(16.0)	(14.0)
13	2028	-	2.1		(16.3)	(14.2)
14	2029	-	2.2		(16.6)	(14.4)
15	2030	2.6	2.2		(17.1)	(12.3)
16	2031	-	2.3		(17.6)	(15.3)
17	2032	-	2.3		(18.2)	(15.8)
18	2033	-	2.4		(19.5)	(17.1)
19	2034	-	2.4		(19.3)	(16.9)
20	2035	-	2.5		(19.9)	(17.4)
21	2036	2.9	2.6		(20.5)	(15.1)
22	2037	-	2.6		(21.2)	(18.5)
23	2038	-	2.7		(22.2)	(19.5)
24	2039	-	2.8		(23.1)	(20.3)
25	**Total**	**$114.1**	**$51.6**	**$23.0**	**($360.2)**	**($171.5)**
26	**NPV**	Discount Rate	6.54%		($159.8)	($20.8)

Source: Response to Question No. KLC/Metro 19, page 2 of 3.

LOUISVILLE GAS & ELECTRIC COMPANY
AMS Deployment Cost-Benefit Analysis: Gas

Line	Year	Capital Costs	O&M Costs	Meter Retirement	Benefits	Total Net Benefits
		(1)	(2)	(3)	(4)	(5)
1	2016	$0.1	$0.0		$0.0	$0.1
2	2017	16.6	0.1		(0.2)	16.6
3	2018	16.6	0.1		(0.6)	16.1
4	2019	16.2	0.3		(2.7)	13.8
5	2020	0.5	0.7		(2.8)	(1.6)
6	2021	-	0.8		(2.6)	(1.8)
7	2022	-	0.8		(2.6)	(1.8)
8	2023	-	0.8		(2.7)	(1.9)
9	2024	0.9	0.8		(2.7)	(0.9)
10	2025	-	0.8		(2.7)	(1.9)
11	2026	-	0.9		(2.8)	(1.9)
12	2027	-	0.9		(3.0)	(2.2)
13	2028	-	0.9		(3.0)	(2.1)
14	2029	-	0.9		(3.0)	(2.1)
15	2030	1.1	0.9		(3.0)	(1.0)
16	2031	-	1.0		(3.1)	(2.1)
17	2032	-	1.0		(3.2)	(2.2)
18	2033	-	1.0		(3.6)	(2.6)
19	2034	-	1.0		(3.3)	(2.3)
20	2035	-	1.1		(3.4)	(2.3)
21	2036	1.2	1.1		(3.5)	(1.1)
22	2037	-	1.1		(3.5)	(2.4)
23	2038	-	1.2		(3.7)	(2.6)
24	2039	-	1.2		(3.9)	(2.7)
25	**Total**	**$53.3**	**$19.4**	**$0.0**	**($65.6)**	**$7.2**
26	**NPV**	Discount Rate	6.54%		($30.0)	$24.1

Source: Response to Question No. KLC/Metro 19, page 2 of 3.

LOUISVILLE GAS & ELECTRIC COMPANY

Proposed Class Revenue Allocation
Measured on Total Revenues Including Adjustment Clauses
Forecast Test Year Ending June 30, 2018
(Dollar Amounts in $000)

Line	Customer Class	Present Sales Revenue	Proposed Revenue Increase Amount	Proposed Revenue Increase Percent	Relative Increase
		(1)	(2)	(3)	(4)
1	Residential Rate RS	$441,518	$42,132	9.5%	115%
2	General Service GS	170,462	12,181	7.1%	86%
3	Power Service Primary Rate PSP	12,536	1,035	8.3%	99%
4	Power Service Secondary Rate PSS	164,894	11,631	7.1%	85%
5	Time of Day Rate Primary TODP	126,342	10,385	8.2%	99%
6	Time of Day Rate Secondary TODS	84,413	5,698	6.8%	81%
7	Retail Transmission Service Rate RTS	68,896	5,824	8.5%	102%
8	Special Contract #1	6,922	605	8.7%	105%
9	Special Contract #2	3,520	288	8.2%	99%
10	Lighting Rate RLS & LS	23,389	1,920	8.2%	99%
11	Lighting Rate LE	245	-	0.0%	0%
12	Lighting Rate TE	304	21	6.8%	81%
13	Total Retail	$1,103,441	$91,720	8.3%	100%
	Other Revenues				
14	Curtailable Rider	(4,335)	1,920	-44.3%	
15	Other Charges	21,784	(22)	-0.1%	
16	**Total Revenues**	$1,120,891	$93,618	8.4%	

LOUISVILLE GAS & ELECTRIC COMPANY
Proposed Class Revenue Allocation
Measured on Base Revenue Excluding
Embedded Fuel Charges
Forecast Test Year Ending June 30, 2018
(Dollar Amounts in $000)

Line	Customer Class	Present Base Revenue	Embedded Fuel Costs at 2.725¢/kWh	Base Revenue Excluding Embedded Fuel Charges	Proposed Revenue Increase Amount	Proposed Revenue Increase Percent	Relative Increase
		(1)	(2)	(3)	(4)	(5)	(6)
1	Residential Rate RS	$379,200	$113,907	$265,293	$42,132	15.9%	112%
2	General Service GS	135,826	37,016	98,810	12,181	12.3%	87%
3	Power Service Primary Rate PSP	11,518	4,504	7,013	1,035	14.8%	104%
4	Power Service Secondary Rate PSS	151,571	51,080	100,491	11,631	11.6%	82%
5	Time of Day Rate Primary TODP	116,919	50,377	66,542	10,385	15.6%	110%
6	Time of Day Rate Secondary TODS	77,629	21,686	55,944	5,698	10.2%	72%
7	Retail Transmission Service Rate RTS	64,285	31,272	33,012	5,824	17.6%	125%
8	Special Contract #1	6,342	2,994	3,348	605	18.1%	128%
9	Special Contract #2	3,293	1,582	1,711	288	16.9%	119%
10	Lighting Rate RLS & LS	18,141	2,773	15,368	1,920	12.5%	88%
11	Lighting Rate LE	211	90	120	-	0.0%	0%
12	Lighting Rate TE	270	85	185	21	11.1%	78%
13	Total Retail	$965,204	$317,366	$647,838	$91,720	14.2%	100%

LOUISVILLE GAS & ELECTRIC COMPANY

Summary of Class Cost-of-Service Study Results
at Present and Proposed Rates: LOLP Method
Forecast Test Year Ending June 30, 2018
(Dollar Amounts in $000)

		Rate of Return		Subsidy		
Line	Customer Class	Present Rates	Proposed Rates	Present Rates	Proposed Rates	Movement To Cost
		(1)	(2)	(3)	(4)	(5)
1	Residential Rate RS	2.04%	4.17%	($57,553)	($62,831)	-9%
2	General Service GS	8.65%	11.37%	16,869	18,349	-9%
3	Power Service Primary Rate PS	7.03%	10.00%	748	951	-27%
4	Power Service Secondary Rate PS	9.70%	12.34%	21,463	22,559	-5%
5	Time of Day Rate Primary TODP	5.39%	8.25%	1,726	3,463	-101%
6	Time of Day Rate Secondary TODS	11.90%	14.39%	16,355	16,565	-1%
7	Retail Transmission Service Rate RTS	4.83%	8.05%	(168)	1,352	-706%
8	Special Contract #1	2.18%	4.80%	(645)	(591)	8%
9	Special Contract #2	3.11%	5.83%	(195)	(160)	18%
10	Lighting Rate RLS & LS	6.01%	7.54%	1,327	272	80%
11	Lighting Rate LE	17.55%	17.50%	39	32	19%
12	Lighting Rate TE	10.39%	13.48%	36	40	-13%
13	Total Retail	4.92%	7.31%	$0	($0)	-47%

LOUISVILLE GAS & ELECTRIC COMPANY
Recommended Class Revenue Allocation
Measured on Base Revenue Excluding Embedded Fuel Charges
Forecast Test Year Ending June 30, 2018
(Dollar Amounts in $000)

Line	Customer Class	Base Revenue Excluding Embedded Fuel Charges	Recommended Revenue Increase Amount	Recommended Revenue Increase Percent	Relative Increase
		(1)	(2)	(3)	(4)
1	Residential Rate RS	$265,293	$56,340	21.2%	150%
2	General Service GS	98,810	8,408	8.5%	60%
3	Power Service Primary Rate PSP	7,013	597	8.5%	60%
4	Power Service Secondary Rate PSS	100,491	8,551	8.5%	60%
5	Time of Day Rate Primary TODP	66,542	8,646	13.0%	92%
6	Time of Day Rate Secondary TODS	55,944	1,777	3.2%	22%
7	Retail Transmission Service Rate RTS	33,012	4,472	13.5%	96%
8	Special Contract #1	3,348	711	21.2%	150%
9	Special Contract #2	1,711	363	21.2%	150%
10	Lighting Rate RLS & LS	15,368	1,852	12.0%	85%
11	Lighting Rate LE	120	0.0	0.0%	0%
12	Lighting Rate TE	185	4.4	2.3%	17%
13	Total Retail	$647,838	$91,720	14.2%	

LOUISVILLE GAS & ELECTRIC COMPANY
Summary of Class Cost-of-Service Study Results at Recommended Rates: LOLP Method

Forecast Test Year Ending June 30, 2018
(Dollar Amounts in $000)

Line	Customer Class	Rate of Return	Subsidy	Movement To Cost
		(1)	(2)	(3)
1	Residential Rate RS	4.89%	(48,553)	16%
2	General Service GS	10.54%	14,576	14%
3	Power Service Primary Rate PSP	8.76%	514	31%
4	Power Service Secondary Rate PSS	11.65%	19,478	9%
5	Time of Day Rate Primary TODP	7.78%	1,723	0%
6	Time of Day Rate Secondary TODS	12.71%	12,644	23%
7	Retail Transmission Service Rate RTS	7.31%	(0)	100%
8	Special Contract #1	5.25%	(485)	25%
9	Special Contract #2	6.52%	(85)	56%
10	Lighting Rate RLS & LS	7.42%	133	90%
11	Lighting Rate LE	17.51%	32	19%
12	Lighting Rate TE	10.99%	24	33%
13	Total Retail	7.31%	(0)	20%

LOUISVILLE GAS & ELECTRIC COMPANY
Proposed Class Revenue Allocation: Gas
Forecast Test Year Ending June 30, 2018
(Dollar Amounts in $000)

Line	Customer Class	Present Delivery Revenue	Proposed Revenue Increase Amount	Proposed Revenue Increase Percent	Relative Increase
		(1)	(2)	(3)	(4)
1	Residential Service Rate RGS	$104,011	$10,631	10.2%	110%
2	Commercial Service Rate CGS	35,390	3,183	9.0%	97%
3	Industrial Service Rate IGS	4,572	2	0.0%	0%
4	As Available Gas Service Rate AAGS	311	(72)	-23.0%	-248%
5	Firm Transportation Service Rate FT	5,841	155	2.7%	29%
6	Total Retail	$150,126	$13,899	9.3%	100%

Exhibit JP-14

LOUISVILLE GAS & ELECTRIC COMPANY
Summary of Gas Class Cost-of-Service Study Results
at Present and Proposed Rates
Forecast Test Year Ending June 30, 2018
(Dollar Amounts in $000)

		Rate of Return		Subsidy		
Line	Customer Class	Present Rates	Proposed Rates	Present Rates	Proposed Rates	Movement To Cost
		(1)	(2)	(3)	(4)	(5)
1	Residential Service Rate RGS	5.08%	6.32%	($7,818)	($7,321)	6%
2	Commercial Service Rate CGS	7.32%	8.48%	3,529	3,490	1%
3	Industrial Service Rate IGS	21.31%	21.29%	2,634	2,428	8%
4	As Available Gas Service Rate AAGS	30.69%	25.05%	315	228	28%
5	Firm Transportation Service Rate FT	11.00%	11.56%	1,340	1,175	12%
6	Total Retail	6.00%	7.19%	$0	($0)	5%

LOUISVILLE GAS & ELECTRIC COMPANY

Recommended Class Revenue Allocation: Gas

Forecast Test Year Ending June 30, 2018

(Dollar Amounts in $000)

Line	Customer Class	Present Delivery Revenue	Recommended Revenue Increase Amount	Recommended Revenue Increase Percent	Relative Increase
		(1)	(2)	(3)	(4)
1	Residential Service Rate RGS	$104,011	$13,970	13.4%	145%
2	Commercial Service Rate CGS	35,390	0	0.0%	0%
3	Industrial Service Rate IGS	4,572	0	0.0%	0%
4	As Available Gas Service Rate AAGS	311	0	0.0%	0%
5	Firm Transportation Service Rate FT	5,841	0	0.0%	0%
6	Total Retail	$150,126	$13,970	9.3%	101%

LOUISVILLE GAS & ELECTRIC COMPANY

Summary of Gas Class Cost-of-Service Study Results
at Recommended Rates

Forecast Test Year Ending June 30, 2018

(Dollar Amounts in $000)

Line	Customer Class	Rate of Return	Subsidy	Movement To Cost
		(1)	(2)	(3)
1	Residential Service Rate RGS	6.72%	($4,033)	48%
2	Commercial Service Rate CGS	7.30%	291	92%
3	Industrial Service Rate IGS	21.28%	2,425	8%
4	As Available Gas Service Rate AAGS	30.67%	299	5%
5	Firm Transportation Service Rate FT	10.99%	1,018	24%
6	Total Retail	7.19%	($0)	74%