**BEFORE THE**

**COUNCIL OF THE CITY OF NEW ORLEANS**

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|---|---|---|
| **REVISED APPLICATION OF ENTERGY** | **)** | |
| **NEW ORLEANS, LLC FOR A CHANGE** | **)** | |
| **IN ELECTRIC AND GAS RATES** | **)** | **DOCKET NO. UD-18-07** |
| **PURSUANT TO COUNCIL RESOLUTIONS** | **)** | |
| **R-15-194 AND R-17-504 AND** | **)** | |
| **FOR RELATED RELIEF** | **)** | |

# DIRECT TESTIMONY

# AND EXHIBITS

# OF

# LANE KOLLEN

**ON BEHALF OF**

**CRESCENT CITY POWER USERS' GROUP**

**J. KENNEDY AND ASSOCIATES, INC.**
**ROSWELL, GEORGIA**

**FEBRUARY 2019**

**BEFORE THE**

**COUNCIL OF THE CITY OF NEW ORLEANS**

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**DIRECT TESTIMONY OF LANE KOLLEN**

## I. QUALIFICATIONS AND SUMMARY

**Q. Please state your name and business address.**

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

**Q. Please state your occupation and employer.**

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

**Q. Please describe your education and professional experience.**

A. I earned a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree from the University of Toledo. I also earned a Master of Arts degree in theology from Luther Rice University. I am a Certified

Public Accountant ("CPA"), with a practice license, a Certified Management Accountant ("CMA"), and a Chartered Global Management Accountant ("CGMA"). I am a member of numerous professional organizations, including the American Institute of Certified Public Accountants, the Institute of Management Accounting, and the Society of Depreciation Professionals.

I have been an active participant in the utility industry for more than thirty years, initially as an employee of The Toledo Edison Company from 1976 to 1983 and thereafter as a consultant in the industry. I have testified as an expert witness on ratemaking, accounting, finance, tax issues, and planning issues in proceedings before regulatory commissions and courts at the federal and state levels on hundreds of occasions, including numerous proceedings before the Louisiana Public Service Commission and the Federal Energy Regulatory Commission involving Entergy Corporation ("Entergy") operating utility companies, including Energy New Orleans, LLC ("ENO" or the "Company").[1]

**Q. On whose behalf are you testifying?**

A. I am testifying on behalf of the Crescent City Power Users Group ("CCPUG"), a group of commercial and government customers taking electric service at retail from ENO.

**Q. What is the purpose of your testimony?**

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[1] My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

A. The purpose of my testimony is to summarize the CCPUG electric and gas base revenue requirement recommendations, address specific issues that affect the Company's electric and gas revenue requirements and claimed base revenue deficiencies, and to address several of the Company's proposed rate riders that will result in additional rate increases over the next three or more years, all else equal.

I address and make recommendations regarding the structure and terms of the Company's proposed Electric Formula Rate Plan ("EFRP"), including recovery of the New Orleans Power Station ("NOPS") revenue requirement after the facility is completed in early 2020; Gas Formula Rate Plan ("GFRP"); and Purchased Power Adjustment Cost Recovery ("PPACR") Rider. CCPUG witness Mr. Richard Baudino addresses and recommends that the Council reject several other of the Company's proposed rate riders, including the Distribution Grid Modernization ("DGM") Rider (electric), Gas Infrastructure Replacement Program ("GIRP") Rider (gas) and Reliability Incentive Mechanism ("RIM") Rider (electric).

If the EFRP and GFRP are adopted, they likely will result in annual rate increases starting in 2020. If the DGM Rider and/or GIRP Rider are adopted, they will result in quarterly rate increases starting in 2020. These rider increases will be above and beyond any rate increases resulting from the EFRP and GFRP or any future base rate proceeding unless and until these riders are terminated. If the RIM Rider is adopted and the Company meets certain reliability performance metrics, it will drive up any rate increases otherwise resulting from the EFRP and DGM Rider due to the resulting increase in return on equity reflected in those two riders.

**Q. Please summarize your testimony.**

A. I recommend that the Council increase ENO's electric base rates by no more than $106.603 million, a reduction of $28.489 million from its requested increase of $135.092 million. I recommend that the Council decrease ENO's gas base rates by no less than $5.813 million, a reduction of $4.893 million from its requested decrease of $0.920 million.

The following table lists each CCPUG adjustment and the effect on the Company's claimed electric and gas base revenue deficiencies. The table also quantifies the effects of the reductions in several of the Company's rate riders due to the transfer, or "roll-in," of certain revenue requirements and expenses from those riders to the electric and gas base revenue requirements. The calculations summarized on the table are detailed in my electronic workpapers, which have been filed with my testimony in the form of an Excel workbook in live format.

**Entergy New Orleans, LLC**
**Summary of CCPUG Revenue Requirement Recommendations**
**Docket No. UD-18-07**
**Period II Test Year Ended December 31, 2018**
**$ Millions**

| | Electric | Gas | Total |
|---|---|---|---|
| **Entergy New Orleans, LLC Requested Rate Change** | | | |
| ENO Request Based on Revised Period II Filing - Base Rates | 135.092 | (0.920) | 134.172 |
| ENO Computed Reduction to Reallign Fuel and Purchased Energy Cost Recovery | (92.408) | - | (92.408) |
| ENO Reduction in Riders PPCACR, MISO, and NNCR | (76.313) | - | (76.313) |
| ENO Increase for AMI Electric and Gas Charge | 7.145 | 0.777 | 7.923 |
| ENO Increase for Interim EECR Rider | 6.006 | - | 6.006 |
| Sum Total of ENO Requested Rate Changes | (20.478) | (0.143) | (20.620) |
| **Effects on Increase of CCPUG Rate Base Recommendations** | | | |
| Remove Plant, A/D, and ADIT Proforma Adjustments Related to 2019 Additions | (5.920) | (1.520) | (7.440) |
| Remove Capital Storm Restoration Costs from Plant | (1.614) | - | (1.614) |
| Remove (Electric) or Reduce (Gas) Asset NOL ADIT | (0.605) | (1.315) | (1.920) |
| Remove Asset ADIT - Deferred Storm Costs | (0.565) | - | (0.565) |
| Remove Reduction to ADIT for Excess ADIT Amortization in 2019 | (0.113) | (0.029) | (0.142) |
| Subtract FIN 48 Liability ADIT in Account 282 | (0.326) | (0.004) | (0.329) |
| Correct Cash Working Capital to Include Dividend Component of Return on Equity | (0.206) | (0.032) | (0.238) |
| Remove Algiers Migration Costs Net of ADIT | (0.310) | - | (0.310) |
| **Effects on Increase of CCPUG Operating Income Recommendations** | | | |
| Remove Forecast 2019 Increases in Payroll and Related Expenses | (0.780) | (0.265) | (1.045) |
| Remove Depreciation Expense Related to 2019 Plant Additions | (3.684) | (0.692) | (4.376) |
| Remove Depreciation Expense Associated With Capital Storm Restoration Costs | (0.565) | - | (0.565) |
| Reduce Depreciation Expense – Use 40 Year Service Life for Union Power Block #1 | (5.029) | - | (5.029) |
| Reduce Depreciation Expense – Use 0% Net Salvage for Union Power Block #1 | (0.628) | - | (0.628) |
| Reduce Depreciation Expense – Correct Patterson Solar Depreciation Rate | (0.070) | - | (0.070) |
| Extend Amortization of Algiers Transaction and Migration Costs to 10 Years | (0.260) | - | (0.260) |
| Remove Amortization of Algiers Migration Costs | (0.862) | - | (0.862) |
| Extend Amortization Period for General Plant Reserve Deficiency from 10 Years to 20 Years | (0.514) | - | (0.514) |
| **Effects on Increase of CCPUG Rate of Return Recommendations** | | | |
| Reflect Short Term Debt | (1.073) | (0.155) | (1.228) |
| Reflect Return on Equity of 9.35% (Electric and Gas) | (5.365) | (0.883) | (6.248) |
| **Total CCPUG Recommendations** | (28.489) | (4.893) | (33.382) |
| **CCPUG Recommendation to Increase/(Decrease) Base Rates** | 106.603 | (5.813) | 100.790 |
| **CCPUG Recommendation to Decrease Overall Rates** | (48.967) | (5.036) | (54.003) |

In the following sections of my testimony, I address each of the issues reflected in the preceding table in greater detail, except for the return on common equity. Mr. Baudino addresses the return on equity, although I quantify the effects of his recommendation on the electric and gas base revenue requirements. I note that the return on equity also will affect the electric and gas revenue requirements in the next several years through various proposed rate riders (EFRP, electric DGM Rider, GFRP, and gas GIRP Rider) if the Council adopts any of these riders, although the effects on the electric and gas revenue requirements cannot be quantified until the Company makes its filings related to those riders in future years.

In addition to the base revenue requirement issues, I recommend that the Council modify the proposed EFRP and GFRP. I recommend that the Council delay the initial EFRP and GFRP filings by one year (from 2020 to 2021) if it does not adopt CCPUG's recommendation to exclude 2019 costs from the base revenue requirement. I recommend other changes to the terms of the EFRP and GFRP. I recommend that the Council reject the Company's proposed increases to the return on equity used in the EFRP for the RIM Rider. I recommend that the Council modify the proposed EFRP to reflect a 50-year service life instead of the proposed 30-year service life in the NOPS revenue requirement. I also recommend that the Council modify the proposed EFRP to reflect the reduction in the NOPS revenue requirement each year as it is depreciated for book and tax purposes.

## II. BASE REVENUE REQUIREMENT ISSUES

### A. Rate Base Issues

#### 1. Remove Plant Additions Forecast for 2019

**Q. Describe the test year for this proceeding specified in Council Resolutions R-15-194 and 17-504.**

A. These resolutions specified a Period I test year for the 12 months ending December 31, 2017 and a Period II test year for the 12 months ending December 31, 2018. In Resolution No. R-15-194, the Council adopted an Agreement in Principle ("AIP") resolving Docket No. UD-14-02 ("Algiers Transaction"). In the AIP, ENO agreed to make a base rate case filing on a combined basis including Algiers and the legacy ENO operations. The AIP states that the base rate case filing will be based on a historical test year ending December 31, 2017 (Period I). Resolution 17-504 cites to the Minimum Filing Requirements in Section 158-44 of the City of New Orleans Code of Ordinances and defines Period II as the 12 months ending December 31, 2018.

**Q. Did the Company abide by the test year designations specified in Resolution 17-504?**

A. No. The Company unilaterally modified both the specified Period I and Period II test years to transform those periods into two different versions of a forecast 2019 test year. It modified the Period I and Period II test year plant and plant-related rate base and expense amounts to include forecast costs that will not be incurred until 2019, or up to 24 months after the end of Period I and up to 12 months after the end of Period II.

More specifically, the Company modified the Period I test year to include actual costs from January 2018 through June 2018 and forecast costs from July 2018 through December 2019, including additions to plant; increases in accumulated depreciation and accumulated deferred income taxes; increases in depreciation expense, insurance expense, and property tax expense related to the increases in plant; and increases in certain operation and maintenance expenses.[2]

Similarly, the Company modified the Period II test year to include forecast costs from January through December 2019, including additions to plant; increases in accumulated depreciation and accumulated deferred income taxes; increases in the depreciation expense, insurance expense, and property tax expense related to the increases in plant; and increases in certain operation and maintenance expenses.[3]

**Q. Was this authorized in Resolution 17-504?**

A. No. Resolution 17-504 sets forth the definitions of the Period I and Period II test years. This Resolution does not authorize adjustments to either test year for forecast costs extending through the end of 2019, which effectively creates a new forecast test year, the 12 months ending December 31, 2019.

Resolution 17-504 states that "the Council expects that as part of ENO's Filing, ENO may annualize and/or normalize (e.g., weather normalize) certain customer, cost, revenue, and balance sheet values in Period I and Period II for regulatory ratemaking treatment." However, such adjustments are limited by the Resolution itself to these revenues and costs "in Period I and Period II," and are not inclusive of adjustments beyond either of those periods.

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[2] Direct Testimony of Orlando Todd at 15.
[3] *Id.*

**Q. What is the effect of including forecast costs after the end of Period I and Period II?**

A. The effect is to substantially increase the revenue requirement for both periods.

**Q. Does the Company cite any authority for departing from the two test years defined in Resolution 17-504?**

A. No. The Company does not explicitly acknowledge that it has departed from the two test years defined in Resolution 17-504 and does not cite any authority for departing from the two test years defined in Resolution 17-504. In fact, it affirms the use of the Period II test year and states that "The 2018 calendar year financial forecast incorporates the most recent, comprehensive analysis of the Company's expected revenues and non-fuel O&M [operation and maintenance] expenses to provide utility service to its customers in the future."[4]

However, it then makes several arguments in support of including forecast costs for 2019 through multiple proforma adjustments. First, it argues that forecast costs for 2019 are "known and measurable."[5] Second, it argues that including costs through December 31, 2019 "better aligns base rates with the cost of providing electric and gas service during the first twelve months that base rates from this proceeding become effective."[6] Third, it argues that including costs through December 31, 2019 "better aligns with the first evaluation period under the

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[4] Direct Testimony of Orlando Todd at 4.
[5] Direct Testimony of Phillip Gillam at 2 and Direct Testimony of Lisa Walther at 17.
[6] Direct Testimony of Orlando Todd, at 15.

proposed Gas and Electric Formula Rate Plans discussed by Company witness Phillip B. Gillam and allows the first evaluation period to serve as a true-up of the plant costs reflected in base rates in this proceeding."[7]

**Q. Are the Company's forecast costs for 2019 known and measurable?**

A. No. Despite the Company's repeated claims to this effect, forecast costs inherently are not known and measurable because they have not actually been incurred. The Council historically has relied on actual costs, subject to known and measurable adjustments to remove certain costs, annualize certain revenues and expenses, and normalize certain other revenues and expenses. The Period I test year, excluding the costs from January 2018 through December 2019, adheres to this precedent. The Period II test year, excluding the forecast costs from January through December 2019, modifies this precedent to reflect more recent data through December 2018, albeit based on partially forecast rate base, rate of return, revenues, and expense data.

**Q. Respond to the Company's argument that using forecast costs for 2019 better aligns base rates with the cost of service.**

A. First and most importantly, the Company's argument is an attempt to circumvent the test year definitions and requirements set forth in Resolution 17-504 and to convert the test year from a historic test year to a forecast test year. Unlike a historic

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[7] *Id.*

test year, a forecast test year is largely untethered to actual revenues and costs and necessarily is based on assumptions about the future and estimates of revenues and costs based on those assumptions.

Second, a forecast test year is inappropriate because the revenues and costs are not known and measurable; they are the result of assumptions and estimates, any and all of which cannot be verified and are subject to bias and manipulation.

Third, the Company's proposal results in a fundamental mismatch of revenues and costs, thus ensuring that the Company will recover revenues that exceed its costs. More specifically, the Company's forecast costs for 2019 include plant additions through December 31, 2019, depreciation expense and other plant-related expenses based on the plant additions through December 31, 2019, and payroll and payroll-related expenses based on costs at December 31, 2019. However, the Company's rates will be reset in this proceeding on or about August 1, 2019, a date some five months before any of the forecast costs after that date will be incurred.

Finally, the Company's variable expenses, as well as certain other expenses, are largely recovered through riders and are not subject to regulatory lag. To the extent that certain fixed costs are recovered based on a historic test year, this ratemaking structure provides an equitable and balanced behavioral ratemaking incentive to constrain the growth in costs. The use of a historic test year promotes good management and a focus on efficiencies, thus restraining cost increases and limiting rate increases.

**Q. Respond to the Company's argument that using forecast costs for 2019 better aligns with the first evaluation period under the Company's proposed EFRP and GRFP.**

A. This argument is completely at odds with the structure and application of the proposed EFRP and GFRP. First, both the EFRP and GFRP are based on historic test years, not forecast test years. The first evaluation period under both plans will be the historic test year 2019. It is consistent and logical that base rates be reset in this proceeding in 2019 based on the historic test year 2018 (Period II), followed by resetting base rates in 2020 under the EFRP and GFRP based on the historic test year 2019.

Second, both the EFRP and GFRP are structured to reset rates prospectively based on a historic test year. By their terms, they are not structured to operate as a true-up mechanism for base rates in the historic test year (evaluation period).

**Q. Is the Period II test year, *excluding* the forecast costs from January through December 2019, reasonable to use for the base revenue requirement?**

A. Yes, subject to a comparison of forecast costs to actual costs for July 2018 through December 2018 to assess whether the forecast costs for those months included in the Period II test year are reasonable. Ultimately, the Council can assess the reasonableness of the forecast costs through the end of 2018 based on actual costs. The Council cannot do so for the forecast costs from January through December 2019.

**Q. Will the Company's proposed EFRP and GFRP provide recovery of increased costs in 2019, after the costs actually are incurred and are known and measurable?**

A. Yes. The Company proposes to use calendar year 2019 as the first Evaluation Period when it makes its EFRP and GFRP filings on or before April 30, 2020. If the Council does not adopt an EFRP or GFRP in this proceeding, then the Company may file another base rate case in 2019 or 2020 if it determines that its actual costs in 2019 justify such a filing.

**Q. What is your recommendation?**

A. I recommend that the Council use the Period II test year, *excluding* forecast costs from January through December 2019, to determine the base revenue requirement. The EFRP and GFRP will provide the Company an opportunity to timely recover any actual increases in its electric and gas base revenue requirement in 2019 through those rate riders starting in 2020.

**Q. What are the effects of your recommendation on the electric and gas revenue requirement of removing the 2019 forecast costs from rate base?**

A. The effects are a reduction of $9.604 million in the electric base revenue requirement and a reduction of $2.211 million in the gas base revenue requirement. These effects include only the reductions due to removing the 2019 forecast costs from the electric and gas rate base and the related depreciation expense. I separately address the effects of removing the Company's proposed adjustments to increase payroll expense based on 2019 forecast costs in the Operating Income Issues section of my testimony.

**2. Remove Capital Storm Costs from Plant and Reimburse the Costs from Storm Reserve Funds**

**Q. Did the Company include plant costs in electric rate base that could have been reimbursed from the storm reserves?**

A. Yes. The Council has authorized the Company to immediately recover its storm costs from two storm reserve accounts instead of including the costs in the base revenue requirement and recovering them over the next 40 or 50 years.

The Company described its "right" to be reimbursed in response to discovery as follows:

> Also, the Company has the right to be reimbursed for capital storm restoration costs from the Storm Reserve Escrow Account pursuant to Resolution R-06-459 and the Securitized Storm Reserve pursuant to the Storm Recovery Reserve Escrow Agreement, which is Appendix E to Resolution R-15-193.[8]

The two storm reserve accounts are the Securitized Storm Reserve Account and the Existing Escrow Account.[9] These storm reserve accounts are pre-funded through securitization proceeds and prior collections from customers, respectively. The balance in the Securitized Storm Reserve Account was $64.6 million at December 31, 2017 and the balance in the Existing Escrow Account was $14.9

[8] Response to CCPUG 2-7. I have attached a copy of this response as my Exhibit___(LK-2).
[9] Direct testimony of Orlando Todd at 33.

million at December 31, 2017.[10] Interest earnings on the Existing Escrow Account were less than 1% in 2017.[11]

Reimbursement from the storm reserves is the least cost form of ratemaking recovery. Instead of choosing the least cost option, the Company chose to include these costs as plant in service in rate base and the related depreciation expense in operating expenses. In his Direct Testimony, Mr. Todd states:[12]

> Q65. AS OF DECEMBER 31, 2017, HAS THE COMPANY INCURRED ANY STORM RESTORATION COSTS ASSOCIATED WITH A POTENTIAL TRIGGERING WEATHER EVENT FOR WHICH IT IS HAS NOT REQUESTED REIMBURSEMENT?
>
> A. Yes. As of December 31, 2017, ENO has incurred $20,706 of deferred O&M and $16.7 million of capital storm restorations costs for which it has not requested reimbursement. The capital storm restorations costs were incurred after December 31, 2011.
>
> ****************************************
>
> Q66. AS OF APRIL 30, 2018, HAS THE COMPANY INCURRED ANY STORM RESTORATION COSTS ASSOCIATED WITH A POTENTIAL TRIGGERING WEATHER EVENT FOR WHICH IT IS WAITING TO REQUEST REIMBURSEMENT?
>
> A. As of April 30, 2018, the Company incurred an additional $0.138 million of deferred O&M and an additional $0.346 million of capital storm restorations costs for which it has not requested reimbursement.
>
> ****************************************
>
> Q67. DOES THE COMPANY INTEND TO SEEK REIMBURSEMENT FROM EITHER OF ITS STORM RESERVES FOR THE

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[10] *Id.*

[11] ENO Exhibit OT-5 attached to the Direct Testimony of Orlando Todd, reporting interest earned of $0.123 million and an account balance of $14.935 million at December 31, 2017. The account balance at January 1, 2017 was $17.279 million based on the account activity during 2017 described in this letter. The earned interest was 0.76% during 2017 ($0.123 million/($14.935 million + $17.279 million)/2).

[12] Direct Testimony of Orlando Todd at 33-34.

CAPITAL STORM RESTORATION COSTS IDENTIFIED ABOVE?

A. No. ENO proposes that those capital storm restoration costs be included in rate base to the extent they have been closed to plant in service less any accumulated depreciation.

**Q. Why is that relevant?**

A. The Company's failure to seek reimbursement for these storm costs unnecessarily and improperly increases costs to customers, who have prepaid storm costs through storm damage expense accruals and presently pay for these costs through securitization charges. The Company had nearly $80 million in its storm reserves at December 31, 2017 that can be used to reimburse storm damage expense and capital (plant) costs. If the Company had obtained reimbursement of these plant costs from the storm reserve accounts, then the gross plant in service included in rate base would be $17.046 million less and the electric base revenue requirement would be less.[13]

In addition, the earnings on the storm reserves are less than 1% compared to the Company's requested return of 9.79% when grossed-up for income taxes. In other words, the least cost recovery option is to seek and obtain reimbursement from the storm reserves, not to include the costs in plant in service and depreciation expense.

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[13] Direct Testimony of Orlando Todd at 33.

**Q. Should the Council remove these plant costs from rate base and direct the Company to obtain reimbursement from the storm reserves?**

A. Yes. The Council has approved a means for reimbursement of these storm costs that is lesser cost and more economic for the Company's customers than including the costs in rate base and operating expenses. The Council should not reward ENO's uneconomic decision not to obtain reimbursement from the storm reserves. If the costs are removed from the base revenue requirement, then the Company will obtain full recovery from the storm reserves.

**Q. What is the effect of your recommendation?**

A. The effect is a reduction of $2.179 million in the electric base revenue requirement, consisting of a reduction in the return on rate base of $1.614 million due to removing the capital costs from electric rate base and a $0.565 million reduction in depreciation expense.

**3. Remove (Electric) or Reduce (Gas) Asset Net Operating Loss ("NOL") Accumulated Deferred Income Taxes**

**Q. Describe the Company's request to include NOL ADIT in electric and gas rate base.**

A. In its revised filing, the Company included NOL ADIT of $5.831 million in electric rate base and $21.245 million in gas rate base for Period I. The Company included

NOL ADIT of $6.184 million in electric rate base and $22.589 million in gas rate base for Period II.[14]

The Company further revised these NOL ADIT amounts in response to Advisors and CCPUG discovery. The Company now proposes NOL ADIT of $0.212 million in electric rate base and $9.788 million in gas rate base for Period I. It now proposes NOL ADIT of $0 in electric rate base and $9.402 million in gas rate base for Period II.[15]

**Q. What are the effects of these reductions in NOL ADIT on the electric and gas base revenue requirements for Period II?**

A. The effects are a reduction of $0.605 million in the electric base revenue requirement and a reduction of $1.315 million in the gas base revenue requirement.

**Q. Is it possible that there will be additional reductions in NOL ADIT in conjunction with the Company's 2018 year-end accounting and in future years, including 2019?**

A. Yes. The NOL ADIT included in rate base is based on unutilized net operating loss carryforwards that were caused by tax depreciation assuming that it was the last deduction in the calculation of taxable income. The Tax Cuts and Jobs Act eliminated "bonus" tax depreciation starting in January 2018, which was the

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[14] Direct Testimony of Joshua Thomas at 73.

[15] Response to CCPUG 6-2 and Advisors 5-9, Addendum 1. I have attached a copy of these responses as my Exhibit___(LK-3).

proximate cause of the net operating losses and NOL carryforwards in prior years, as well as the minimum amount of the NOL ADIT necessary to include in rate base under the federal tax laws and regulations. The greater the taxable income, the more NOL carryforward that can be utilized, which may result in a further reduction in the NOL ADIT actually recorded on the Company's accounting books in conjunction with its 2018 year-end accounting and undoubtedly will result in additional reductions in future years, including 2019.

**Q. Why is this relevant?**

A. If the NOL ADIT recorded on the Company's accounting books in conjunction with its 2018 year-end accounting is less than its most recent calculations provided in response to discovery, then the amount should be updated in a subsequent round of testimony.

Further, if the Council does not reject the Company's proposals to include 2019 costs in rate base and operating expenses, then it also should update and reduce the NOL ADIT based on forecast taxable income in 2019.

**<u>4. Remove Asset Accumulated Deferred Income Taxes – Deferred Storm Costs</u>**

**Q. Describe the asset ADIT due to deferred storm costs included in electric rate base.**

A. The Company included two adjustments to add asset ADIT due to deferred storm costs to rate base. The adjustments are reflected in accounts 283249 and 283250.[16] The two asset ADIT accounts appear to be related to the storm damage reserve accounts, both of which have liability balances. However, the storm damage reserve liability amounts were not subtracted from rate base. Typically, the ratemaking treatment of the reserve accounts and the related ADIT amounts are treated consistently for rate base purposes, i.e., either both are included or both are excluded. In this case, the Company excludes the reserve, so the related ADIT also should be excluded.

**Q. Were these two adjustments in error?**

A. Yes. They should not have been added to rate base given that the storm damage reserve amounts are not subtracted from rate base. The Company acknowledged that the adjustments were in error in response to discovery.[17]

**Q. What is the effect of correcting these errors?**

A. The effect is a reduction of $0.565 million in the electric base revenue requirement.

## 5. Remove Reduction to Accumulated Deferred Income Taxes for Excess ADIT Amortization in 2019

**Q. Describe the recent federal income tax rate reduction and how that affects the level of ADIT in ENO's revenue requirement.**

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[16] Schedule BB-14 and response to Advisors 5-19.
[17] Response to Advisors 5-19. I have attached a copy of this response as my Exhibit___(LK-4).

A. The Tax Cut and Jobs Act ("TCJA") was signed into law on December 22, 2017, reducing the federal corporate income tax rate from 35% to 21% effective January 1, 2018. Among other things, the reduction in the income tax rate reduced the valuation of existing ADIT on the books of ENO as of December 31, 2017. This had the effect of creating excess ADIT on the books of ENO, separated between protected and unprotected excess ADIT.

The TCJA requires that the property-related excess ADIT associated with liberalized depreciation (protected excess ADIT) be amortized based on the Average Rate Assumption Method ("ARAM") while the amortization period for the unprotected excess ADIT is subject to the discretion of the regulator. Council Resolution No. R-18-227 authorized the amortization for the unprotected excess ADIT through Fuel Adjustment Clause Rider credits and offsets to Grid Modernization, Smart City investments, and Energy Smart expenses. The Company removed all unamortized unprotected excess ADIT amounts, as well as the related amortization of such, from the revenue requirement in the instant filing because customers were assumed to be made whole prior to the expected August 1, 2019 date when rates will be reset in this proceeding.

ARAM requires amortization of the protected excess ADIT over the remaining regulatory lives of the property at a rate that parallels the reversal of the related remaining ADIT at the present lower tax rates. The Company did not utilize the booked amounts of the protected excess ADIT amounts as of the December 31, 2018 Period II test year. Instead, it performed proforma adjustments detailed on WPs AJ03F.2 (electric) and AJ03F (gas) to remove an additional year, representing

2019 amortizations, from the liability balances in rate base associated with the protected excess ADIT. ENO increased rate base by $1.155 million and $0.290 million for electric and gas, respectively, related to the 2019 amortizations.

**Q. What is your recommendation?**

A. I recommend that the Commission remove the 2019 amortization of the protected excess ADIT in order to reflect the unamortized balances of excess ADIT as of the end of the Period II test year, December 31, 2018, to determine the base revenue requirement.

**Q. What are the effects of your recommendation on the electric and gas revenue requirements?**

A. The effects are a reduction of $0.113 million in the electric base revenue requirement and a reduction of $0.029 million in the gas base revenue requirement.

## <u>6. Subtract FIN 48 Accumulated Deferred Income Taxes</u>

**Q. Describe the FIN 48 ADIT.**

A. The Company has taken deductions for so-called “uncertain tax positions” (“UTPs”) on its tax returns. The tax savings resulting from these deductions are recorded as “FIN 48” ADIT. The Company is required to disclose UTPs when it files its federal tax returns. If the Company is unsuccessful on audit and appeal, then it must repay the tax savings to the federal government along with interest.[18]

**Q. Has the Company subtracted the FIN 48 ADIT amounts from rate base in the same manner that it subtracts other liability ADIT amounts from rate base?**

A. No.[19] The Company unilaterally decided that it would not subtract the FIN 48 ADIT from rate base.[20]

**Q. What is the effect of the Company's position not to subtract the FIN 48 ADIT from rate base?**

A. The Company's failure to subtract the FIN 48 ADIT from rate base increases rate base and the base revenue requirement.

**Q. If the FIN 48 ADIT is not subtracted from rate base, then do customers ever obtain the carrying charge value of the FIN 48 ADIT?**

A. No. If the FIN 48 ADIT is not subtracted from rate base, then ENO retains the carrying charge savings until the issue is resolved on audit or appeal. Customers paid the income tax expense as if there was no tax deduction. ENO took the tax

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[18] Response to Advisors 5-17. I have attached a copy of this response as my Exhibit___(LK-5).

[19] FIN 48 ADIT by subaccount for electric and gas are listed in HSPM Table 3 in the HSPM Direct Testimony of Joshua Thomas at 71. These amounts were removed from ADIT via proforma adjustments. The Company provided the amounts by account in response to Advisors 1-29 (HSPM). The Company provided a description of the UTCs and the FIN 48 ADIT amounts in response to Advisors 1-30 (HSPM) and response to Advisors 4-3 (HSPM).

[20] Direct Testimony of Joshua Thomas at 72-74.

deduction, reduces its current income tax expense and cash payments to the federal and state governments, and then retains the carrying charge value on the savings.

ENO also records interest expense on the savings in the event the deduction is disallowed and it is required to repay the savings plus interest. However, the savings in the carrying charges is much greater than the accrued interest expense. If the deduction is sustained on audit, then ENO reverses the interest that it accrued as an increase to income. If the deduction is disallowed on audit, then ENO pays the interest, but still retains the carrying charge savings in excess of the interest. In no event, do the customers ever receive all the carrying charge savings or even the difference between the carrying charge savings and the accrued interest expense unless and until the deduction is sustained and base rates are reset to reflect the entirety of the carrying charge savings going forward.

**Q. Is that equitable?**

A. No. The Company retains all or a portion of the carrying charge savings regardless of whether the deduction is sustained or not, or if sustained, until base rates are reset. These savings should inure to customers, subject to customer payment of any interest that ultimately is paid if the deduction is disallowed after the date when the FIN 48 ADIT savings actually are reflected in rates. If the deduction is disallowed, then interest for the relevant period should be deferred as a regulatory asset recoverable from customers.

**Q. What is your recommendation?**

A. I recommend that the Council subtract the FIN 48 ADIT amounts from rate base. If the IRS subsequently denies the deduction on audit and the Company is required to repay the tax savings, then I recommend that the Council authorize the Company to record a regulatory asset and seek recovery in a future ratemaking proceeding for the interest paid to the IRS calculated from the date when rates are reset in this proceeding.

**Q. What are the effects of your recommendation?**

A. The effects are a reduction of $0.326 million in the electric base revenue requirement and a reduction of $0.004 million in the gas base revenue requirement.

**<u>7. Correct Cash Working Capital to Include Effect of Dividend Component of Return on Equity</u>**

**Q. Did the Company include the net cash expense lag for the dividend component of the return on equity in the lead/lag study?**

A. No. The Company used the lead/lag approach in the calculation of cash working capital ("CWC") included in rate base. However, the Company failed to include the dividend component of the return on equity as a cash expense in the cash working capital calculation.[21] The return on equity consists of a dividend return plus a growth factor under the DCF methodology or a dividend return and a

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[21] The cash working capital revenue lag days and expense lag days are shown on ENO Exhibit KFG-2 (Attachment A for electric and Attachment B for gas) attached to the Direct Testimony of Kenneth Gallagher.

premium under the risk premium methodology or a dividend return and a risk-adjusted premium under the capital asset pricing methodology.

**Q. Is the dividend component of the return a cash expense (disbursement)?**

A. Yes. The dividend component of the return on equity is a cash disbursement (expense). Consequently, it should be reflected in the cash working capital calculation, along with all other cash expenses recovered in the revenue requirement. The dividend is paid quarterly, so the service period is 45.63 days (365 divided by 4 divided by 2). The dividend is paid approximately 8 weeks after the end of the quarter,[22] so the payment lag is approximately another 56 days. Thus, the total expense lag is 101.6 days.

**Q. What is your recommendation?**

A. I recommend that the Council correct the Company's CWC calculation to include the dividend component of the return on equity. It is a cash expense and should be included in the CWC calculation.

**Q. What are the effects of your recommendation?**

A. The effects are a $0.206 million reduction in the electric base revenue requirement and a $0.032 million reduction in the gas base revenue requirement.

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[22] https://entergycorporation.gcs-web.com/dividend-history.

## **B. Operating Income Issues**

### **1. Remove Forecast 2019 Increases in Payroll and Related Expenses**

**Q. Describe the Company's adjustment for a forecast 2019 increase in payroll and related expenses in the electric and gas operating expenses.**

A. The Company proposes an adjustment (AJ05) to increase electric and gas operating expenses for forecast increases of 3% in wages and related expenses in 2019.[23]

**Q. What is your recommendation?**

A. I recommend that all forecast 2019 payroll and payroll related cost increases included by the Company in the Period I and Period II revenue requirements be removed from operating expenses. They are not authorized by Resolution 17-504 or any other Resolution and are not known and measurable.

**Q. What are the effects of your recommendation?**

A. The effects are a reduction of $0.780 million in the electric base revenue requirement and a reduction of $0.265 million in the gas base revenue requirement.

### **2. Reduce Depreciation Expense – Use 40 Year Service Life for Union Power Block #1**

[23] Direct Testimony of Lisa Walther at 16

**Q. Describe the service life proposed in the depreciation study for Union Power Block #1.**

A. The Company proposes a 30-year service life in the depreciation study. The Union Power Block #1 is a combined cycle unit and is operated as a base load unit, meaning that it operates in every hour that it clears the MISO energy markets.

**Q. Is a 30-year service life reasonable?**

A. No. It is excessively short. The Company will continue to operate and maintain this capacity as long as it is economic for it to do so. The service lives for combined cycle units may be 40 years or more based on a review of actual service lives reported by the Energy Information Administration ("EIA"). The EIA maintains a publicly available data base of retired and operating electric generating units that includes the installation dates and retirement dates for retired units since 2002 and the installation dates as well as the planned retirement dates for operating units.

The EAI data indicates that there are combined cycle units that were in service for 40 to 50 years before their retirements, including AEP Texas North Company's Rio Pecos Units 4 and 5 and Anchorage Municipal Light and Power's George M Sullivan Generation Plant 2 Unit 5, among others, and combined cycle units that have been in operation for 40 to 50 years and still remain in operation, including Florida Power & Light Company's Lauderdale Units ST 4 and 5 and Fort

Meyer Units ST 1 and 2, Duke Energy Indiana, LLC's Noblesville Units 1 and 2, and Entergy Louisiana LLC's Sterlington Unit 7, among others.[24]

**Q. What is your recommendation?**

A. I recommend that the Council set the service life at 40 years for depreciation rate and expense purposes. A service life of 40 years is consistent with the actual service lives of many combined cycle units based on the EIA information for both retired and operating units. The service life used for depreciation purposes is inherently a forecast and will be informed by experience and future expectations in future depreciation studies and rate proceedings. The service life can be adjusted in future rate proceedings if the Council determines that the service life will be shorter or longer than 40 years. Depreciation studies and rates continuously adjust for changes in the service life and other assumptions. Ultimately, the Company will fully recover the cost of the asset. The regulator has to determine the reasonable service life every time it reviews and approves proposed depreciation rates.

**Q. What is the effect of your recommendation?**

A. The effect is a reduction of $5.029 million in the electric base revenue requirement.

## 3. Reduce Depreciation Expense – Use 0% Net Salvage for Union Power Block #1

[24] Energy Information Administration November 2018 Form EIA-860M.

**Q. Describe the Company's proposal to include net negative salvage in the calculation of the depreciation rate and expense for Union Power Block #1.**

A. The Company proposes to use a negative 8% salvage rate in the calculation of the depreciation rate and expense for Union Power Block #1. This increases the calculated depreciation rate by 8% compared to including no net salvage in the calculation of the depreciation rate.

The Company has no history of retirements or net salvage for Union Power Block #1, meaning that its actual experience is 0% net salvage. In response to CCPUG discovery, the Company stated:

> Since the Union Power Block was purchased by Entergy in 2016, there is no salvage or cost of removal history specifically related to the facility. The -8% net salvage estimate was based on the experience of Entergy Louisiana for Other Production, which includes facilities similar to the Union Power Block. The net salvage analysis for Entergy Louisiana is included in the attached.

**Q. Is it reasonable to use Entergy Louisiana's retirements and salvage history as a proxy for Union Power Block #1?**

A. No. There is insufficient data to determine the type or age of the equipment that is reflected in "other production" for Entergy Louisiana or even if the retirements are related to unusual or terminal events rather than recurring interim retirements. This type of data analysis typically is used only for interim retirements, which typically are relatively minor compared to the total gross plant in service.

**Q. Even if the Entergy Louisiana retirements and salvage history could serve as a proxy, should the negative 8% be applied to the total Union Power Block #1 gross plant in service?**

A. No. As I noted previously, even if the data is a reasonable proxy for Union Power Block #1 *interim* retirements, Company witness Mr. Clayton erroneously applied this salvage rate to the total gross plant in service instead of the portion of the gross plant in service that is exposed to interim retirement. For example, if the gross plant in service is $100 million, but only $10 million is exposed to interim retirement, then it would be an error to apply the negative 8% salvage rate to the $100 million instead of to the $10 million.

**Q. What is your recommendation?**

A. I recommend that the Council adopt a depreciation rate of Union Power Block #1 that includes 0% salvage. First, the Company's proposed negative 8% is not based on any ENO-specific interim retirement or salvage history. Second, there is no compelling reason to accept the ELL-specific interim retirement and salvage history as a proxy for the Union Power Block #1interim retirement and salvage history. Third, even if the ELL-specific history is a reasonable proxy, then it was erroneously applied to the total Union Power Block #1 gross plant in service, not just to the portion exposed to interim retirement.

**Q. What is the effect of your recommendation?**

A. The effect is a reduction of $0.628 million in the electric base revenue requirement.

**4. Correct Error In Patterson Solar Depreciation Rate and Expense**

**Q. Describe the error in the Patterson Solar depreciation rate.**

A. The Company acknowledged an error in the depreciation study performed by Mr. Clayton for the Patterson Solar facility in response to CCPUG discovery.[25] The correct depreciation rate for the Patterson Solar facility should be 4.01%, not the 4.35% reflected in the depreciation study and used to calculate the depreciation expense included in the electric base revenue requirement.

**Q. What is the effect of correcting this error?**

A. The effect is a $0.070 million reduction in the electric base revenue requirement.

**5. Extend Amortization of Algiers Transaction Costs to 10 Years**

**Q. Describe the Company's proposed amortization of the deferred Algiers Transaction costs.**

A. The Company proposes a 3-year amortization of the deferred Algiers transaction costs. The Company tied the 3-year amortization period for the deferred Algiers transaction costs to the term of the proposed EFRP, but did not cite any reason for the 5-year amortization period for the deferred Algiers migration costs.

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[25] Response to CCPUG 2-18. I have attached a copy of this response as my Exhibit___(LK-6).

**Q. Is a three-year amortization period reasonable?**

A. No. It is unnecessarily short and increases the electric base revenue requirement. It is not tied to any specific period for any specific reason. The proposed 3-year amortization for the deferred Algiers transaction costs has nothing to do with the proposed EFRP and the recovery of the amortization expense will continue after the three-year term of the EFRP until base rates are reset of the EFRP is extended beyond the initial three-year term.

**Q. What is your recommendation?**

A. I recommend a 10-year amortization period to minimize the effect on the base revenue requirement and to minimize the potential over-recovery if the EFRP is not renewed after its initial three-year term.

**Q. What is the effect of your recommendation?**

A. The effect is a reduction of $0.260 million in the electric base revenue requirement.

## 6. Remove Algiers Migration Costs

**Q. Describe the Company's proposal to defer and amortize the forecast Algiers migration costs.**

A. The Company proposes to defer and amortize the Algiers migration costs, include these costs in rate base, and amortize the deferred amount over five years. The Algiers migration costs will be incurred in 2018 and 2019 to facilitate the billing of former Algiers customers as ENO customers and to eliminate current back-office processes and associated expenses.[26] The Company forecasts that it will incur $4.277 million for this purpose.

**Q. Does the Company expect there to be savings from the Algiers migration?**

A. Yes. The Company's witnesses acknowledge there will be savings. Mr. Todd states that it will "eliminate current back-office processes and associated expenses..."[27] Ms. Stewart states "It will also enhance ENO's operations in that, currently, there is an administratively intensive back-office process required to move payments received on former ELL-Algiers customer accounts to ENO. It will also enhance operations in that there will be fewer bills generated each month, resulting in lower mailing costs."[28]

**Q. Has the Company proposed to offset the forecast costs with the savings?**

A. No.

**Q. What is your recommendation?**

A. I recommend that the Council authorize the deferral for actual costs incurred, but require that the Company offset these deferrals with the savings, and in this manner, amortize the deferral as the savings are achieved.

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[26] Direct Testimony of Orlando Todd at 26-27.
[27] *Id.*
[28] Direct Testimony of Melonie Stewart at 48.

I recommend that the Council remove the forecast costs from rate base and the related amortization from operating expenses.

In the event that the Company does not recover the entirety of the deferred costs in this manner, then I recommend it seek recovery of the remaining deferred costs in its next base rate proceeding.

**Q. What is the effect of your recommendation?**

A. The effect is a reduction of $1.171 million in the electric base revenue requirement. This includes the effect of removing the costs from rate base and removing the related amortization expense.

## 7. Extend Amortization Period for General Plant Reserve Deficiency from 10 Years to 20 Years

**Q. Describe the Company's proposal to amortize a general plant reserve deficiency over 10 years.**

A. ENO's depreciation witness, Mr. Clayton, states: "The Company has been using a scheduled retirements approach for its general plant other than structures and improvements for many years. However, the existing rates for electric general plant have been too low, and the book reserve as of the study date was approximately $10.2 million lower than it should have been. This portion of the book reserve was separated so that it could be recovered over a 10-year period."[29]

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[29] Direct Testimony of Donald Clayton at 14.

**Q. Is the 10 years a reasonable amortization period?**

A. No. It is unnecessarily short given the magnitude of this general plant reserve deficiency. This reserve deficiency was "separated" from the general plant asset accounts and is based on a comparison of the actual depreciation reserve compared to a theoretical depreciation reserve. In other words, there are no specific assets related to this reserve deficiency. Instead, it is simply an amount to balance the Company's accounts and ensure that its plant assets are fully depreciated and recovered over time. I would also note that it is unusual to separate any theoretical reserve surplus or deficiency in this manner, especially for only one category of plant.

**Q. What is your recommendation?**

A. I recommend that the Council use a 20-year amortization period to reduce the effect on the revenue requirement. The Company still will fully recover this cost, but over a longer period of time. The Company also will recover a return on this cost, so it should be indifferent on a net present value basis.

**Q. What is the effect of your recommendation?**

A. The effect is a reduction of $0.514 million in the electric base revenue requirement.

## C. Rate of Return Issues

### 1. Include Short-Term Debt in Capitalization

**Q. Describe how the Company uses short-term debt.**

A. The Company has available two sources of short-term debt. The first source is the internal Entergy Money Pool whereby Entergy operating utilities that have a surplus of cash deposit it into the Money Pool and the Entergy operating utilities that need cash borrow it from the Money Pool.

The second source is an external Company-specific credit facility of $25 million, which includes fronting commitments of up to $10 million for the issuance of letters of credit against the borrowing capacity of the facility.

The Company may borrow up to $150 million from the Entergy Money Pool, other internal short-term borrowing arrangements, and external sources pursuant to FERC authorization.

**Q. Describe the Company's short-term borrowing and investment history.**

A. The Company has been both a borrower from and investor in the Entergy Money Pool, although it has been a borrower on balance over the last three years. In 2016, 2017 and 2018, ENO generally was a borrower from the Entergy Money Pool, except for temporary periods when it was an investor after it issued new long-term debt.[30]

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[30] Response to CCPUG 2-31. The Company has designated the attachment to this response as HSPM.

In 2018, the Company was a borrower from the Entergy Money Pool at the end of April, May, June, July, and August, although it also borrowed from the Entergy Money Pool during other months. The 13-month average short-term debt using month-end balances outstanding was $7.870 million, although it borrowed as much as $43.7 million on any one day.

**Q. Why does ENO use short-term debt?**

A. It used short-term debt because it is the lowest cost form of financing. In 2018, the cost of its Entergy Money Pool borrowings was only $0.153 million, or slightly less than 2.0% based on the 13-month average outstanding. This cost compares very favorably with the Company's cost of a new long-term debt issue in September 2018 at 4.0%. It also compares very favorably with the Company's requested cost of common equity at 10.75%, which actually is 14.65% when grossed-up for the income taxes, bad debt, and regulatory fees included in the revenue requirement.

**Q. Did ENO include any amount of short-term debt in its proposed capital structure and cost of capital?**

A. No. ENO proposes a capital structure of 47.80% in long-term debt at an average cost of 4.82% and 52.20% in common equity at a cost of 10.50% for the electric and of 10.75% for the gas base revenue requirements.

**Q. Is it reasonable to exclude short-term debt from the capital structure and cost of capital?**

A. No. ENO uses short-term debt to reduce its actual financing costs. However, even if it did not, it nevertheless should use some amount of short-term debt in lieu of long-term debt and common equity to reduce its cost of capital and its revenue requirements.

**Q. What is your recommendation?**

A. I recommend that the Council include approximately $16.8 million of short-term debt in the capital structure so that it comprises 2.0% of total capitalization. It is reasonable to include short-term debt in the cost of capital because it is the lowest cost form of financing. This is a very modest amount and well below the $150 million authorized by FERC.

I recommend that the Council use a 2.0% cost for the short-term debt. That is consistent with the Company's recent actual cost of borrowings from the Entergy Money Pool and is consistent with other short-term debt interest rates.

**Q. What are the effects of your recommendation to include short term debt in the capital structure?**

A. The effects are a reduction of $1.073 million in the electric base revenue requirement and a reduction of $0.155 million in the gas base revenue requirement. These quantifications are based on the electric rate base and gas rate base after the CCPUG recommended adjustments.

**2. Quantification of CCPUG Return on Equity Recommendation**

**Q. What are the effects of the CCPUG return on equity recommendation addressed by Mr. Richard Baudino?**

A. The effects are a $5.365 million reduction in the electric base revenue requirement and a $0.883 million reduction in the gas base revenue requirement. These quantifications are based on the electric rate base and gas rate base after the CCPUG recommended adjustments.

**Q. What are the effects of each 0.10% return on equity?**

A. The effects of each 0.10% return on equity are $0.468 million on the electric base revenue requirement and $0.063 million on the gas base revenue requirement.

**Q. How does the capital structure and cost of capital compare between the Company's request and the CCPUG recommendations?**

A. The following table provides a side by side comparison of the Company's request to the CCPUG recommendations.

**Entergy New Orleans, LLC**
**Capital Structure and Cost of Capital Comparison**
**Company vs. CCPUG Recommendation**

| As Filed By Company | | | | | | |
|---|---|---|---|---|---|---|
| Source | Capital Amount | Capital Ratio | Electric Component Costs | Electric Weighted Avg Cost | Gas Component Costs | Gas Weighted Avg Cost |
| Short Term Debt | - | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| Long Term Debt | 400.973 | 47.80% | 4.82% | 2.30% | 4.82% | 2.30% |
| Common Equity | 437.936 | 52.20% | 10.50% | 5.48% | 10.75% | 5.61% |
| Total Capital | 838.909 | 100.00% | | 7.79% | | 7.92% |

| CCPUG Recommendation | | | | | | |
|---|---|---|---|---|---|---|
| Source | Capital Amount | Capital Ratio | Electric Component Costs | Electric Weighted Avg Cost | Gas Component Costs | Gas Weighted Avg Cost |
| Short Term Debt | 16.778 | 2.00% | 2.00% | 0.04% | 2.00% | 0.04% |
| Long Term Debt | 392.954 | 46.84% | 4.82% | 2.26% | 4.82% | 2.26% |
| Common Equity | 429.177 | 51.16% | 9.35% | 4.78% | 9.35% | 4.78% |
| Total Capital | 838.909 | 100.00% | | 7.08% | | 7.08% |

## III. ELECTRIC FORMULA RATE PLAN

### A. Summary of Company's Proposed Electric Formula Rate Plan

**Q. Describe the Company's proposed electric Formula Rate Plan.**

A. The Company's proposed electric Formula Rate Plan is patterned after a prior EFRP approved by the Council for ENO, but includes several modifications. The prior EFRP was implemented for a limited three-year term and has not been in effect for many years.

The Company's proposed EFRP is addressed primarily by ENO witness Mr. Phillip Gillam, although other ENO witnesses address various components or aspects of the proposal. The prior EFRP included the following components, which the Company proposes be included in the new EFRP as follows:

- Evaluation Period defined as previous calendar year.

- Target Evaluation Period Cost of Equity ("EPCOE") equivalent to authorized return on equity set in this proceeding.

- Earnings dead band with midpoint equivalent to the EPCOE minus and plus 30 basis points. If earnings are within the deadband, then there will be no change in rates.

- Formula to calculate prospective base rate increase or reduction if the Earned Rate of Return on Equity ("EROE") is above or below the dead band. Revenue deficiency or sufficiency for the Evaluation Period based on the EPCOE, referred to as "resetting to the midpoint."

- Seventy-five day review period.

- Three-year term.

- Specified dispute resolution procedure.

In addition, Mr. Gillam proposes the following modifications to the components of the prior EFRP:

- A filing date for the Evaluation Report by April 30 of the year following each Evaluation Period, followed by a rate adjustment, if any, in the first billing cycle in September. The modification extends the date for the rate adjustment by 45 days compared to the prior plan, from July 15 to September 1.

- An expanded earnings deadband of minus and plus 50 basis points. This would result in an earnings deadband of 10.00% to 11.00%, if the Company's proposed return on equity of 10.50% is adopted without upward adjustment for the proposed RIM.

- Exclusion of the costs of Energy Smart, the Lost Contribution to Fixed Costs associated with Energy Smart, and the related energy efficiency incentives or penalties. These costs would be recovered through the Interim Energy Efficiency Cost Recovery Rider and, later, the Demand-Side Management Cost Recovery Rider.

- Addition of a new class allocation methodology applied to any rate increase or reduction if earnings are outside the deadband. The former FRP applied the same percentage increase or reduction to each class.

- Addition of a new provision specifically for the recovery of the NOPS revenue requirement. This provision is included in Section III *Provisions for Other Rate Changes* of the proposed EFRP tariff.[31] the Company initially proposes to use for recovery of the first year NOPS non-fuel revenue requirement starting in early 2020 and continuing until base rates again are reset, most likely through a subsequent base rate proceeding. The rate increase will be timed to coincide with the NOPS in-service date and will be independent of the FRP calculations and any other rate change in September 2020 if earnings are outside the deadband.

- Addition of a new provision to address changes in the income tax rates, such as those that were enacted in the Tax Cuts and Jobs Act.

- An increase in the provision for Extraordinary Cost Changes from a $2 million threshold to a $6 million threshold.

**Q. Do you agree that an FRP can be a reasonable ratemaking approach?**

A. Yes. However, it is essential that the structure and terms of the FRP are reasonable, not only for the FRP itself, but also in conjunction with other forms of ratemaking recovery, most notably other riders, including any performance incentives or disincentives.

### <u>B. EFRP Implementation should be Delayed Until 2021, Except for NOPS Provision, if Council does not Adopt CCPUG Recommendation to Exclude 2019 Costs from Base Revenue Requirement</u>

**Q. Do you agree with the Company's proposal to implement the EFRP in 2020**

[31] This new provision is identified as Section III.C *New Orleans Power Station* in the proposed EFRP tariff provided as ENO Exhibit PBG-7 attached to Mr. Gillam's Direct Testimony.

**and to use 2019 as the first Evaluation Period?**

A. Yes, but only if the Council adopts the CCPUG recommendation to exclude all proforma adjustments to rate base and operating income for calendar year 2019. If, instead, the Council adopts ENO's proposal to include proforma adjustments for calendar year 2019, an implementation date of 2020 and Evaluation Period of 2019 essentially provides the Company a second base rate increase based on a 2019 test year, thereby providing a true-up to the base revenue requirement determined in this proceeding, including potentially an increase in the return on equity, all else equal.

**Q. What is your recommendation?**

A. I agree with an implementation date of 2020 based on a calendar year 2019 Evaluation Period, but only if the Council adopts the CCPUG recommendation to exclude all proforma adjustments for 2019. However, if the Council allows proforma adjustments for 2019, then I recommend that it delay the implementation date for the EFRP to 2021, except for the NOPS revenue requirement.

### <u>C. NOPS Revenue Requirement and Recovery through the EFRP</u>

**Q. Describe the Company's proposal to include a new component in the electric FRP to recover the costs of the New Orleans Power Station.**

A. The Company presently expects that NOPS will be completed and placed in commercial operation in January 2020.[32] The Company seeks recovery of the NOPS revenue requirement through an interim rate adjustment as specified in its proposed EFRP. It proposes that the interim rate adjustment be based on the first year NOPS revenue requirement. It does not propose any subsequent reduction in this interim rate adjustment to reflect the declining revenue requirement as the plant investment is depreciated for book and tax purposes.

**Q. Is it reasonable to include an interim rate adjustment in the EFRP to recover the costs of the New Orleans Power Station?**

A. Yes, but only if the costs included in the calculation of the interim rate adjustment are reasonable. They are not. The proposal will provide excessive recovery in the first year and every year thereafter until base rates are reset. This will occur for three reasons. The first reason is that the return is excessive. The Company's proposed return on equity is excessive for base revenue requirement purposes and also is excessive for the NOPS revenue requirement, based on CCPUG witness Mr. Richard Baudino's independent analysis of the required return on equity. The Company proposes a 10.50% return on equity for the NOPS revenue requirement.[33] Mr. Baudino recommends a 9.35% return on equity for the base revenue requirement. The Council should use the same return on equity for the base revenue requirement and the NOPS revenue requirement.

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[32] Direct Testimony of Orlando Todd at 29.

[33] Direct Testimony of Orlando Todd at 31.

The second reason is that the depreciation rate and depreciation expense are excessive. The Company simply assumed a service life of 30 years. However, combustion turbines typically have a service life of 40 to 50 or more years based on the EIA data for retired and operating generating units that I previously cited in conjunction with my testimony on the service life for Union Power Block #1. The EAI data indicates that there are combustion turbine units that were in service for nearly 50 years or more before their retirement, including Florida Power & Light Company's Lauderdale Units 1, 2, 4, 6-24, and Port Everglades Units 1-12, Entergy Arkansas, Inc.'s Mableville Units 1 and 3, and South Carolina Electric & Gas Company's Burton Units 1-3, among others, and combined cycle units that have been in operation for nearly 50 years or more and still remain in operation, including Florida Power & Light Company's Lauderdale Units 3 and 5, Duke Energy Florida, LLC's Higgins Units P1-P4, Louisville Gas & Electric Company's Paddy's Run Units 11 and 12, and MidAmerican Energy Company's River Hills Units 1-7, among others. NOPS is a peaking unit, as are other internal combustion and combustion turbine generating units. Peaking units operate infrequently and only when they clear the MISO market. They are not operated continuously in the same manner as nuclear, coal-fired, or gas-fired combined cycle units and tend to have longer service lives than combined cycle units.

The third reason the Company's proposal will result in excessive recovery is that the revenue requirement generally is at the maximum amount in the first year and then continuously declines due to the accumulation of book depreciation (accumulated depreciation) and the tax savings from accelerated tax depreciation in excess of straight line tax depreciation (ADIT), both of which are subtracted from rate base and reduce the revenue requirement as these amounts continue to grow. The decline in the revenue requirement is greatest in the earliest years of new generation.

**Q. What is your recommendation?**

A. I recommend that the Council make three changes to the Company's proposed NOPS recovery. The first change is to reduce the return on equity to 9.35% or whatever other return on equity it authorizes for the base revenue requirement. The second change is to reduce the first-year revenue requirement to reflect a 50-year service life. The third change is to require the Company to reduce the revenue requirement each year to reflect an additional year of depreciation and deferred income tax expense (reflected in greater accumulated depreciation and ADIT).

**Q. Have you quantified the effect of your recommendations on the first-year revenue requirement?**

A. Yes. The first-year revenue requirement should be reduced by $4.073 million, to $29.072 million from the Company's estimated $33.145 million,[34] consisting of a $1.574 million reduction due to the CCPUG recommendation for a 9.35% return on equity and a $2.499 million reduction due to the use of a 50-year service life.

[34] Direct Testimony of Orlando Todd at 30 and ENO Exhibit OT-3.

### D. Other Provisions of Proposed EFRP

**Q. Do you have comments on other provisions of the proposed EFRP?**

A. Yes. The Attachments to the proposed EFRP should be modified to reflect the Council's Resolution in this proceeding. For example, CCPUG recommends that the Commission adjust the capital structure to include short-term debt, if any, using a 13 month average, or to reduce common equity to exclude short term investments, if any, using a 13 month average. If the Council adopts this recommendation, then Attachment D should be modified to reflect this determination. As another example, Attachment E specifies that the EPCOE shall be 10.50%, the return on equity requested by the Company in this proceeding. If the Council adopts the 9.35% return on equity recommended by CCPUG or a different return on equity, then that return on equity should be reflected on Attachment E.

## IV. GAS FORMULA RATE PLAN

### A. Summary of Company's Proposed Gas Formula Rate Plan

**Q. Describe the Company's proposed GFRP.**

A. The Company's proposed GFRP is patterned after a prior GFRP approved by the Council for ENO, but includes several modifications. The proposed GFRP is similar to the proposed EFRP, although each reflects provisions that are unique to the electric revenue requirement or to the gas revenue requirement. The prior GFRP was implemented for a limited three-year term and has not been in effect for several years.

The Company's proposed GFRP is addressed primarily by ENO witness Mr. Phillip Gillam, although other ENO witnesses address various components or aspects of the proposal. The prior GFRP included the following components, which the Company proposes be included in the new GFRP as follows:

- Evaluation Period defined as previous calendar year.
- Target Evaluation Period Cost of Equity ("EPCOE") equivalent to authorized return on equity set in this proceeding.
- Earnings dead band with midpoint equivalent to the EPCOE minus and plus 30 basis points. If earnings are within the deadband, then there will be no change in rates.
- Formula to calculate prospective base rate increase or reduction if the Earned Rate of Return on Equity ("EROE") is above or below the dead band. Revenue deficiency or sufficiency for the Evaluation Period based on the EPCOE, referred to as "resetting to the midpoint."
- Seventy-five day review period.
- Three-year term.
- Specified dispute resolution procedure.

In addition, Mr. Gillam proposes the following modifications to the components of the prior GFRP:

- A filing date for the Evaluation Report by April 30 of the year following each Evaluation Period, followed by a rate adjustment, if any, in the first billing cycle in September, essentially 123 days after the filing date for the Evaluation Report.
- An expansion of the earnings deadband to minus and plus 50 basis points. This would result in an earnings deadband of 10.25% to 11.25%, if the Company's proposed return on equity of 10.75% is adopted.
- Addition of a new provision to address changes in the income tax rates, such

as those that were enacted in the Tax Cuts and Jobs Act.

- An increase in the provision for Extraordinary Cost Changes from a $0.750 million threshold to a $1 million threshold.

**<u>B. GFRP Implementation should be Delayed Until 2021 if Council does not Adopt CCPUG Recommendation to Exclude 2019 Costs from Base Revenue Requirement</u>**

**Q. Do you agree with the Company's proposal to implement the GFRP in 2020 and to use 2019 as the first Evaluation Period?**

A. Yes, but only if the Council adopts the CCPUG recommendation to exclude all proforma adjustments to rate base and operating income for calendar year 2019. If, instead, the Council adopts ENO's proposal to include proforma adjustments for calendar year 2019, an implementation date of 2020 and Evaluation Period of 2019 essentially provides the Company a second base rate increase based on a 2019 test year, essentially providing a true-up to the base revenue requirement determined in this proceeding, including potentially an increase in the return on equity, all else equal.

**Q. What is your recommendation?**

A. I agree with an implementation date of 2020 based on a calendar year 2019 Evaluation Period, but only if the Council adopts the CCPUG recommendation to exclude all proforma adjustments for 2019. However, if the Council allows proforma adjustments for 2019, then I recommend that it delay the implementation date for the EFRP to 2021.

### C. Other Provisions of Proposed GFRP

**Q. Do you have comments on other provisions of the proposed GFRP?**

A. Yes. The Attachments to the proposed GFRP should be modified to reflect the Council's Resolution in this proceeding. For example, CCPUG recommends that the Commission adjust the capital structure to include short-term debt, if any, using a 13-month average, or to reduce common equity to exclude short term investments, if any, using a 13-month average. If the Council adopts this recommendation, then Attachment D should be modified to reflect this determination. As another example, Attachment E specifies that the EPCOE shall be 10.75%, the return on equity requested by the Company in this proceeding. If the Council adopts the 9.35% return on equity recommended by CCPUG or a different return on equity, then that return on equity should be reflected on Attachment E.

## V. PURCHASED POWER AND CAPACITY ACQUISITION COST RECOVERY RIDER

**Q. Describe the Company's proposed revised Purchased Power and Capacity Acquisition Cost Recovery Rider.**

A. The Company proposes a revised PPCACR rider that reflects: 1) the difference (positive or negative) between purchased power agreement ("PPA") capacity expenses and long-term service agreement ("LTSA") expenses that are included in the base revenue requirement when base rates are reset in this proceeding, consistent with the concept of an "exact recovery" process for these expenses; 2) the non-fuel revenue requirement related to constructed and/or acquired capacity (*e.g.*, a power plant similar to the Union Acquisition), which could also include future capacity projects such as battery storage capacity projects; and 3) the expenses incurred related to new PPAs and new LTSAs the Company may enter into.[35]

**Q. Is it reasonable to allow the Company to include any and all revenue requirements for newly constructed or acquired capacity or the expenses related to new PPAs and new LTSA the Company may enter into?**

A. No. These provisions of the proposed revised PPCACR tariff would allow the Company to include these costs without review or further action by the Council, except for a review of the initial estimated revenue requirement for newly constructed or acquired capacity. That is inappropriate for both types of costs, especially those costs that were not subject to certification or prior review before the Company consummated the transactions, including any transactions with affiliates. Although the proposed revised tariff does require the Council to determine the initial estimated monthly revenue requirement for newly constructed or acquired capacity, it does not set forth or describe a process for the Council to review this initial estimated monthly revenue requirement or whereby any

[35] Direct Testimony of Phillip Gillam at 42 and ENO Exhibit PBG-11 attached to Mr. Gillam's testimony.

intervenor party could review and potentially contest the calculations of the revenue requirements.

**Q. What is your recommendation?**

A. I recommend that the proposed tariff be modified so that no revenue requirement for newly constructed or acquired capacity or no expenses for new PPAs or LTSA may be included without action by the Council and without an opportunity for the Council to review the reasonableness of the transactions and agreements as well as setting forth a process to allow intervenors to review the transactions and agreements as well as the revenue requirements and expenses that will be included in the rider.

**Q. Does this complete your testimony?**

A. Yes.

**BEFORE THE**

**COUNCIL OF THE CITY OF NEW ORLEANS**

| | | |
|---|---|---|
| **REVISED APPLICATION OF ENTERGY** | **)** | |
| **NEW ORLEANS, LLC FOR A CHANGE** | **)** | |
| **IN ELECTRIC AND GAS RATES** | **)** | **DOCKET NO. UD-18-07** |
| **PURSUANT TO COUNCIL RESOLUTIONS** | **)** | |
| **R-15-194 AND R-17-504 AND** | **)** | |
| **FOR RELATED RELIEF** | **)** | |

**EXHIBITS**

**OF**

**LANE KOLLEN**

**ON BEHALF OF THE**

**CRESCENT CITY POWER USERS' GROUP**

**J. KENNEDY AND ASSOCIATES, INC.**
**ROSWELL, GEORGIA**

**FEBRUARY 2019**

# AFFIDAVIT

STATE OF GEORGIA )

COUNTY OF FULTON )

LANE KOLLEN, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Lane Kollen

Sworn to and subscribed before me on this
1st day of February 2019.

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2019
CHEROKEE COUNTY, GEORGIA