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	**)**	

SURREBUTTAL AND CROSS-ANSWERING TESTIMONY AND EXHIBITS OF LANE KOLLEN

ON BEHALF OF

CRESCENT CITY POWER USERS' GROUP

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

APRIL 26, 2019

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

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SURREBUTTAL AND CROSS-ANSWERING TESTIMONY OF LANE KOLLEN

I. 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. Did you previously file testimony in this proceeding?

A. Yes. I previously filed Direct Testimony on behalf of the Crescent City Power Users Group ("CCPUG"). In that testimony, I addressed numerous revenue requirement issues; summarized the revenue requirement effect of the CCPUG recommendations; addressed 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; addressed the Company's proposed Gas Formula Rate Plan ("GFRP"); and addressed the

Company's proposed Purchased Power Adjustment Cost Recovery ("PPACR") Rider.

Q. What is the purpose of your Surrebuttal and Cross-Answering Testimony?

A. The purpose of my testimony is to provide a revised summary of CCPUG electric and gas base revenue requirement recommendations, respond to the Rebuttal Testimony of certain Company witnesses, and respond to the Direct Testimony of the City's Advisors ("Advisors") and certain intervenor witnesses.

More specifically, I respond to Company witness Mr. Joshua Thomas on the issues of 1) adjustments to rate base and operating income beyond the end of the Period II test year, 2) storm damage recoveries, 3) amortization and depreciation expense, 4) short-term debt in the capital structure, 5) proposed EFRP and GFRP, and 6) the parameters for recovery of the costs of the New Orleans Power Station ("NOPS") in the EFRP.

I respond to Company witnesses Mr. Donald Clayton and Mr. Robert Breedlove on the service lives relevant to the depreciation rates for Union Power Block #1. I also respond to Mr. Clayton on the net negative salvage relevant to the depreciation rates for Union Power Block #1 and the amortization period for the general plant theoretical depreciation reserve deficiency.

I respond to Company witness Mr. Kenneth Gallagher on the cash dividend component of the return on equity included in the cash working capital calculation using the lead/lag approach.

None of the Company's witnesses responded to my Direct Testimony on the following issues: 1) the Company's failure to defer the depreciation expense that it continued to collect for the Michoud and Patterson power stations after they were retired the Company discontinued depreciation expense, 2) the Company's failure to update and reduce or eliminate electric and gas NOL ADIT through the end of 2019 in the event the Council adopts the Company's adjustments to extend the test year from December 31, 2018 to December 31, 2019, one year after the end of the Period II test year, 3) the Company's failure to remove asset ADIT related to storm cost reserves, 4) restoration of the excess ADIT to December 31, 2018, 5) use of a 10 year amortization period for Algiers transaction costs, and 6) removal of Algiers migration costs and CCPUG proposal to allow the Company to recover such costs through retained savings.

In addition to the Company's witnesses, I respond to Advisors' witnesses Mr. Victor Prep, Mr. Joseph Rogers, and Mr. Byron Watson on the following issues: 1) adjustments to rate base and operating income beyond the end of the Period II test year, 2) modifications to the Company's proposed EFRP, GFRP, and PPCACR Riders, and 3) rejection of the proposed AMI Rider.

Finally, I respond to Air Products' witness Mr. Maurice Brubaker on 1) adjustments to rate base and operating income beyond the end of the Period II test year, and 2) modifications to the Company's proposed EFRP and GFRP and other Riders.

Q. Please summarize your Surrebuttal and Cross-Answering Testimony.

A. I recommend that the Council increase ENO's electric base rates by no more than $108.863 million, a reduction of $26.229 million from its requested increase of $135.092 million. I recommend that the Council reduce ENO's gas base rates by at least $5.806 million, a reduction of $4.886 million from its requested reduction of $0.920 million

The following table lists each CCPUG adjustment and the effect the Company's claimed electric and gas base revenue deficiencies. The calculations summarized on the table are detailed in my electronic workpapers, which have been filed with my Surrebuttal and Cross-Answering Testimony in the form of an Excel workbook in live format.

Entergy New Orleans, LLC
Summary of CCPUG Revenue Requirement Recommendations - Surrebuttal and Cross-Answering Update
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	(3.482)	(1.486)	(4.968)
Remove Capital Storm Restoration Costs from Plant	(1.694)	(0.018)	(1.712)
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	(0.432)	(0.006)	(0.438)
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	(1.112)	(0.155)	(1.267)
Reflect Return on Equity of 9.35% (Electric and Gas)	(5.558)	(0.885)	(6.443)
Total CCPUG Recommendations	(26.230)	(4.886)	(31.116)
CCPUG Recommendation to Increase/(Decrease) Base Rates	108.863	(5.806)	103.057
CCPUG Recommendation to Decrease Overall Rates	(46.707)	(5.029)	(51.736)

In addition to the revenue requirement issues, I continue to recommend that the Council modify the Company's proposed EFRP and GFRP. More specifically, 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 that the Council address the parameters of the NOPS recovery in this proceeding, as the Company proposed in its Application and Direct Testimony, and reject the Company's new proposal to delay those issues until some later date.

I recommend that the Council modify the proposed EFRP to reflect a 40-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. Further, I recommend that the Council modify the EFRP and GFRP to reflect the return on equity authorized in this base rate proceeding.

I recommend that the Council reject Advisors' recommendation to include forecast costs beyond the historic evaluation period in the Company annual EFRP and GFRP filings.

I recommend that the Council reject the Company's proposed increases to the return on equity used in the EFRP for the RIM Rider.

Finally, I recommend that the Council adopt the Company's proposed AMI Rider and reject Advisors' recommendation to include the AMI costs in the base revenue requirement and in the EFRP.

II. BASE REVENUE REQUIREMENT ISSUES

A. Test Year Issues

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

A. No. Contrary to the test year designations specified in Resolution 17-504, the Company 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 18 months after the end of Period 1 and up to 12 months after the end of Period 2.

Q. Mr. Thomas states that Resolution 17-504 "contains no language prohibiting ENO from proposing adjustments to reflect cost levels expected in 2019."[1] Is that relevant?

A. No. What is relevant is the fact that the Period I and Period II test years and adjustments allowed to those test years were directives set forth in Resolution 17-504; these were not mere guidelines subject to unilateral modification by the Company. The Company effectively ignored the Council's directives and filed its case using an altogether different test year than set forth in the Resolution, namely calendar year 2019, and using post-test year adjustments for this purpose, which are not annualization or normalization adjustments as specified in the Resolution.

Either the Resolution controls or it does not and the Company has offered no legal or other reason why the Council should ignore the substantive terms of its own Resolution controlling the filing in this proceeding.

The Resolution states that these test years and filing requirements are consistent with and prescribed by the Code of Ordinances of the City of New Orleans ("Code"). Neither the Resolution nor the Code authorize the extension of Period I or Period II by either 18 or 12 months, respectively, through the end of

[1] Rebuttal Testimony of Joshua Thomas at 52.

2019. Yet the Company unilaterally modified the two test years to convert them into a forecast 2019 test year.

Further, the Resolution states that "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."[2] In other words, the Resolution expressly allows the Company to make adjustments to annualize or normalize costs ***in*** the test year, but it does not authorize the Company to make adjustments to reflect cost levels that expected in 2019 and that will not be incurred until ***after*** the end of the test year.

Q. Mr. Thomas claims that the Code allows adjustments for "known and measurable" changes. Are "expected" cost levels in 2019 "known and measurable"?

A. No. Generally, revenues and costs are not known and measurable until they are incurred. The revenues and costs can be adjusted to "annualize" and/or "normalize" the amounts "in" Period I and II for regulatory ratemaking treatment. Annualization and normalization adjustments typically are made to actual revenues and costs in a historic year to weather normalize revenues, remove unusual and/or nonrecurring revenues or costs, and to annualize the effects of known and measurable changes in revenues and costs, such as an increase in payroll costs that was implemented during the test year.

[2] Emphasis added to highlight the word "in."

Generally, forecast revenues and costs after the historic test year are not known and measurable. By definition, they have not been incurred. By definition, they are not known and are not measurable. They are simply estimates of future revenues and costs. Forecasts of revenues and costs necessarily are based on assumptions, estimates, and models, as is the case with ENO's forecasts of these amounts for 2019. It is virtually certain that the actual revenues and costs will not match the forecasts of revenues and costs. The actual revenues and costs, when actually received and incurred, will be more or less than the forecasts.

Q. Mr. Thomas asserts that "Mr. Kollen's second reason [only costs actually incurred are known and measurable] would prohibit all pro forma adjustments despite the Code's definition." Is that correct?

A. No. Resolution 17-504 allows proforma adjustments to annualize or normalize revenues and costs actually incurred in the test year for changes that actually are known and measurable.

Q. Will the Company's proposed EFRP and GFRP provide recovery of actual changes in revenues and costs incurred in 2019 and future years with minimal regulatory lag?

A. Yes. The proposed EFRP and GFRP are designed to reset rates to reflect changes in actual revenues and costs within eight months after the end of each historic test year ("evaluation period").

Q. What adjustments have you removed from the Company's proposed revenue requirement?

A. I have removed all post-test year forecast 2019 plant additions, including the related accumulated depreciation, accumulated deferred income taxes ("ADIT"), depreciation expense, and ad valorem expense. I revised the quantifications of the plant-related amounts in the Summary section of my testimony in response to the Company's Rebuttal Testimony regarding other adjustments that it made to remove AMI and grid modernization costs from the forecast 2019 plant additions. In addition, as I described in my Direct Testimony, I have removed all post-test year increases in payroll expenses and related expenses.

B. Rate Base Issues

1. Correct Accumulated Depreciation for Understated Michoud and Patterson Depreciation

Q. Did the Company respond to this issue in its Rebuttal Testimony?

A. No. The Council should adopt the CCPUG recommendation on this issue. It is unrebutted.

2. Remove Capital Storm Costs from Plant And Reimburse The Costs from Storm Reserve Funds

Q. Did the Company acknowledge that it could have sought reimbursement of the storm costs from its storm reserve funds?

A. Yes.

Q. Did the Company address the fact that its failure to obtain reimbursement of the storm costs from its storm reserve funds harms customers through an increase in the revenue requirement?

A. No.

Q. Mr. Thomas asserts that the Company failed to seek reimbursement of other storm costs from the storm reserve funds. Does this in any way justify its failure to do so with respect to the costs that you identified?

A. No. The Company is entitled to seek and obtain reimbursement for storm costs from the storm reserve funds. The cost to use these available funds is less than the Company's proposal to include the storm costs in rate base. The fact that the Company failed to seek reimbursement for other costs is evidence of a pattern of bad behavior that harms customers in order to increase its top line revenues and bottom-line earnings.

Q. Mr. Thomas claims that the Company's failure to seek reimbursement from the storm reserve funds preserves their liquidity. Please respond.

A. The claim assumes that the Company needs to preserve the storm reserve funds for some future undefined storm costs and implies that the funds provide liquidity that otherwise is not available. Mr. Thomas fails to demonstrate that, if the CCPUG recommendation were adopted, ENO would lack sufficient storm reserve funds or that the Company does not have other sources of funding and liquidity in the event of future storm costs. To the contrary, the Company does have other sources of funding and liquidity for that purpose, including access to short term borrowings through its revolving line of credit.

Q. Mr. Thomas claims that the adjustment, if adopted, should be separated between electric and gas, and the electric separated between transmission and distribution. Do you agree?

A. Yes.

Q. Have you revised your quantification of the adjustment and the effect on the base revenue requirement to reflect these refinements?

A. Yes. This is reflected in the table in the Summary section of my testimony and in the electronic workpapers that were filed along with my testimony.

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

Q. Did the Company respond to this issue in its Rebuttal Testimony?

A. No. Mr. Roberts addressed the Advisors' recommendations, but did not address my recommendation. No other Company witness addressed my recommendation. The Council should adopt the CCPUG recommendation on this issue. It is unrebutted.

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

Q. Did the Company respond to this issue in its Rebuttal Testimony?

A. No. The Council should adopt the CCPUG recommendation on this issue. It is unrebutted.

<u>5. Remove Reduction to Accumulated Deferred Income Taxes for Excess ADIT Amortization in 2019</u>

Q. Did the Company respond to this issue in its Rebuttal Testimony?

A. No. The Council should adopt the CCPUG recommendation on this issue. It is unrebutted.

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

Q. Mr. Rory Roberts claims that "no one expects the aggressive tax positions to produce cost-free capital." Is that statement correct?

A. No. First, the Company took the deduction resulting in the FIN 48 ADIT because there was a *probability* that the deduction would be upheld and not denied. In that case, the deduction would generate cost-free capital. The Company has offered no reason, let alone any compelling reason, why it should be allowed to retain the entirety of those savings.

Second, even if the deduction ultimately is denied, then the Company will be required to pay interest on the tax that otherwise would have been paid, but at a significantly lower interest rate than the Company's cost of capital, including the gross-up for income taxes, recovered through the ratemaking process. In other words, the Council (and ENO's ratepayers) would be better off using the FIN 48 ADIT as a reduction to rate base and then allowing the Company to defer and recover interest expense that it pays to the federal government if the deduction ultimately is denied.

The Company has offered no reason, let alone any compelling reason, why the Council should not adopt CCPUG's recommendation to subtract the FIN 48 ADIT from rate base. Under the CCPUG recommendation, the Company is protected and made whole if the deduction is denied.

The CCPUG recommendation is fair and equitable to the Company and its customers. The Company's position is one-sided and inequitable to its customers.

C. Operating Income Issues

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

Q. Mr. Clayton implies that the Company used a 40-year service life adjusted for hypothetical interim retirements averaging 2.5% per year to derive the 30 year service life used for depreciation purposes. Did the Company actually do this?

A. No. This is an after the fact attempt to justify an unreasonably short 30-year service life. The Company used a 30-year service life, which it derived from a probable retirement date of 2034, according to its response to CCPUG discovery.

Union Power Block #1 was completed and placed in service in June 2003.[3] Mr. Clayton testified that the Company provided the probable retirement date of 2034.[4] Mr. Clayton calculated the service life on this basis alone, not a hypothetical probable retirement date of 2044 with some hypothetical interim retirements that somehow reduced the service life to 30 years.

Q. Mr. Clayton compares the Company's proposed service life of 30 years to estimated service lives for other generating units. Is that comparison of any probative value?

A. No. Mr. Clayton attempts to justify the Company's proposed service life of 30 years to the estimated service lives of other generating units that do not have lengthy operating histories. In other words, he attempts to use estimated service lives for other generating units to justify the Company's estimated service life for Union Power Block #1.

In contrast to Mr. Clayton's after the fact justification, I compared the service life to actual and estimated service lives of other generating units that do have lengthy operating histories, which demonstrates that a service life of 30 years is inordinately short.

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[3] Response to CCPUG 2-18. I have attached a copy of this response as my Surrebuttal and Cross-Answering Exhibit___(LK-1).

[4] Direct Testimony of Donald Clayton at 8.

Q. Mr. Clayton and Mr. Breedlove state that components of the generating unit will need to be refurbished throughout its life in order for it to continue operating.[5] Do you agree?

A. Yes. This is true of all generating units. However, these are future costs necessary to ensure that the generating unit is able to continue operating going forward. These costs have not yet been incurred, will not be included in rate base unless and until they are incurred and found to be prudent, and will not be included in depreciation rates or expense unless and until they have been incurred and found to be prudent. These costs will fall into one of two categories: maintenance expense, in which case the Company will recover the future cost as an expense in the ratemaking process, or capital expenditures, in which case the Company will capitalize the cost to plant in service. It then will depreciate it over the remaining life of the asset at that time, or over an extended time in the event the capital expenditure extends the life of the asset going forward, and will recover this future cost as depreciation expense and return on the related rate base investment in the ratemaking process, again assuming the expenditure is found to be prudent.

Q. Mr. Clayton and Mr. Breedlove also claim that Union Power Block #1 is a newer technology that is not as durable as older technology. Please respond.

[5] Direct Testimony of Donald Clayton at 4 and Rebuttal Testimony of Breedlove at 7.

A. Neither witness offers any support for this claim. This is sheer speculation. In any event, as I noted previously, components that are replaced in the future will be included in rate base and depreciation expense in the future. These costs do not need to be addressed in this proceeding. The Company will continue to incur maintenance expense and capital expenditures to operate the asset as long as it is economic to do so. It is entirely possible that it may be economic to operate Union Power Block #1 for more than 40 years.

Q. Mr. Breedlove carries the claim even further that Union Power Block #1 is a newer technology and argues that there is no evidence that generators of this newer vintage can or will operate economically as long as similar generators of older vintage. Please respond.

A. To the contrary, the Company has offered no evidence that generators of this newer vintage cannot or will not operate economically as long as or longer than similar generators of older vintage.

The Council has to make a decision on the service life of this asset for depreciation purposes. Nobody knows for certain what the actual service life of the asset will be because nobody can know with certainty what has not yet occurred. Instead, the Council has to use informed judgment on this issue. The best evidence is the fact that other similar generating assets have actual service lives that are equal to or greater than 40 years. It is better to use the longer service life rather than an inordinately shorter life to ensure that there is a better matching of the costs of the asset to the period over which it likely will be used.

Q. Mr. Thomas claims that the CCPUG depreciation recommendations will cost customers more over time.[6] Is that correct?

A. No. This claim is simplistic and misleading because it fails to consider the economic (present) value of the revenue requirements over the life of Union Power Block #1. The Company will recover the plant cost of this asset plus a *return on* the plant cost less accumulated depreciation and less ADIT over the life of the plant regardless of whether it is depreciated over 40 years or 30 years. The net present value of the revenue requirements under either depreciation life is the same. It is simply a matter of timing. Ratepayers should not be required to pay more in the earlier years of the plant's life simply because the Company seeks to front load the recovery of the depreciation.

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

Q. Mr. Clayton argues that the Council should rely on other utilities' estimates of net salvage rather than the Company's actual net salvage data for Union Power Block #1. Please respond.

A. There are several reasons why the Council should reject the Company's position. First, Mr. Clayton's reliance on other utilities' estimates of net salvage is contrary to standard practice in depreciation studies and the underlying statistical analysis

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[6] Rebuttal Testimony of Joshua Thomas at 57.

performed for those studies. It is standard practice to rely exclusively on a utility's actual statistical experience to determine interim retirements and the related cost of removal and salvage income. The Company's actual experience to date is $0 for cost of removal and $0 for salvage income.

Second, if the Company has actual cost of removal and/or actual salvage income in the future, then this history can be incorporated into subsequent depreciation studies and future depreciation expense in future ratemaking proceedings.

Third, it is unnecessary and there is no reason to use hypothetical net negative salvage values to prematurely recover costs that the Company has not yet and may never incur. The Company is not harmed if the Council does not include such hypothetical costs in the depreciation rates in this proceeding. If the Company actually incurs such costs in the future before the next depreciation study and new depreciation rates are adopted, then the actual costs are deferred as a matter of accounting and preserved for future recovery as a matter of ratemaking. More specifically, the actual cost of removal is recorded for accounting purposes as a reduction to accumulated depreciation and the actual salvage income is recorded for accounting purposes as an increase to accumulated depreciation. The net effect of these "deferred" costs is reflected in the accumulated depreciation included in the next depreciation study and then recovered through the depreciation rates authorized in future rate proceedings.

3. Correct Amortization of Retired Plant Net Book Value for Understated Michoud and Patterson Accumulated Depreciation

Q. Did the Company respond to this issue in its Rebuttal Testimony?

A. No. The Council should adopt the CCPUG recommendation on this issue. It is unrebutted.

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

Q. Mr. Clayton argues that the remaining service life for general plant accounts is approximately 5.9 years, which is less than the 10 years the Company proposes for the general plant theoretical reserve deficiency. Please respond.

A. The Company proposes to amortize the theoretical reserve deficiency over some period different than the remaining lives of the assets in the general plant accounts. In this case, I agree with the Company that using a different amortization period is appropriate because there no longer is any relationship between the physical lives of the assets and the remaining dollars to be recovered. Thus, the Council can use any period that it deems appropriate. A longer amortization period minimizes the effect on the revenue requirement in this proceeding.

5. Extend Amortization of Algiers Transaction Costs to 10 Years

Q. Did the Company respond to this issue in its Rebuttal Testimony?

A. No. The Council should adopt the CCPUG recommendation on this issue. It is unrebutted.

6. Remove Algiers Migration Costs

Q. Did the Company respond to this issue in its Rebuttal Testimony?

A. No. The Council should adopt the CCPUG recommendation on this issue. It is unrebutted.

D. Rate of Return Issues

1. Include Short-Term Debt in Capitalization

Q. Mr. Thomas opposes including short-term debt in capitalization because there may not be funds available to borrow from the Money Pool and the Company does not plan on using short-term debt to finance rate base investment going forward. Please respond.

A. The Council should reject both arguments. With respect the first argument, the Company's ability to borrow on a short-term basis is not dependent on the availability of funds in the Money Pool.

The Company has authority to borrow up to $150 million on a short-term basis from internal sources (Money Pool) and external sources (credit facilities and commercial paper).[7] The Company maintains a credit revolver, which

[7] Entergy Corporation 2018 SEC Form 10-K at 125.

provides a separate external source of short-term borrowings. It has $25 million available pursuant to the credit revolver,[8] although it has not borrowed against this source during the most recent 13-month period.[9]

With respect to the second argument, it is circular, self-serving, and irrelevant for ratemaking purposes. It matters not whether the Company wants to or plans to use short term borrowings. The Council must determine if it is reasonable for the Company to use short term borrowings, and if so, then it should include short-term debt in the capital structure. As I noted in my Direct Testimony, short-term debt is the least cost form of financing and the Council should reflect this in the capital structure and reasonable cost of capital. After the Council has made this decision, then the Company is free to make its own decision on whether to use short-term debt to reflect the Council's ratemaking decision.

Finally, I would note that the Company has not rebutted the facts that I cited in my testimony, namely that it actually does have the ability to borrow short-term, that short-term debt is the least cost, and that it will reduce costs to their customers.

Q. Have you modified your quantification of the CCPUG short term debt recommendation?

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[8] *Id.*, 124.

[9] Response to APC 2-8. I have attached a copy of this response as my Surrebuttal and Cross-Answering Exhibit___(LK-2).

A. Yes. The effect of my short-term debt recommendation is a reduction of $1.112 million in the electric revenue requirement and a reduction of $0.155 million in the gas revenue requirement. These quantifications reflect the effects of revisions that I made to the quantifications of certain CCPUG rate base adjustments.

2. Quantification of CCPUG Return on Equity Recommendation

Q. Have you modified your quantification of the CCPUG return on equity recommendation?

A. Yes. The effect of Mr. Baudino's recommendation is a reduction of $5.558 million in the electric revenue requirement and a reduction of $0.885 million in the gas revenue requirement. These quantifications reflect the effects of revisions that I described previously and made to the quantifications of certain CCPUG rate base adjustments.

III. ELECTRIC AND GAS FORMULA RATE PLAN

A. EFRP and GFRP Implementation Should Be Delayed Until 2021, Except for NOPS Provision in EFRP, If Council Does Not Adopt CCPUG Recommendation to Exclude 2019 Costs from Base Revenue Requirement

Q. Mr. Thomas opposes a delay in the EFRP and the GFRP implementation claiming that the Council has previously used overlapping test years for setting base rates. Even if correct, does that justify a similar result in this proceeding?

A. No. The Council should consider the merits of such an overlap in this proceeding without regard to what has or has not been done in the past. Such an overlap is a fundamental flaw in the Company's proposal to extend the Period I and Period II test years through the end of 2019 using forecast costs and then use the EFRP and GFRP to true-up the forecast test year to the historic evaluation period. This overlap will be recurring and the harm will be further compounded if Advisors proposal to include forecast costs in the EFRP and GFRP is adopted.

B. Council Should Reject Advisors' Proposal to Modify Company's EFRP and GFRP to Adjust Historic Evaluation Period for Forecast Costs

Q. Describe Advisors' proposal to modify the Company's EFRP and GFRP to include adjustments for forecast increases in costs beyond the historic evaluation period.

A. Advisors propose to modify the historic evaluation period proposed by the Company in this proceeding, and previously used in prior versions of the EFRP and GFRP, into a poorly defined forecast evaluation period. The Company would be allowed to include twelve months of forecast capital additions subsequent to the historic test year in the calculation of the revenue requirement.

Q. Does the Company agree with this proposal?

A. Yes. Not surprisingly, Mr. Thomas was practically effusive in his support for this proposal.[10]

Q. Is it appropriate to modify the evaluation period from a historic test year to a forecast test year?

A. No. If adopted, this proposal would fundamentally and negatively change the ratemaking process. The proposal would allow the Company to annually and continuously increase rates based on forecast costs that it develops with the near certainty that these costs will be recovered in real-time as they are incurred. Such a change to the structure of the EFRP and GFRP would provide the Company a behavioral incentive to increase its costs, not reduce or effectively and efficiently manage them.

The Company's proposed EFRP and GFRP already provide a significant reduction of any potential harm to the Company from regulatory lag without the delay and cost of a traditional base rate proceeding. There is no compelling need for the Council to further modify the ratemaking process to essentially provide the Company contemporaneous recovery of its forecast plant-related costs as those costs are incurred.

The Company's proposed EFRP and GFRP provide an objective structure for recovery of costs that are based on the Company's actual cost structure and that are known and measurable. The Company's proposed EFRP and GFRP are

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[10] Rebuttal Testimony of Joshua Thomas at 52.

anchored in reality. The Advisors' proposal will allow the Company to propose, include, and recover hypothetical forecast costs that are not known and measurable and that may never actually be incurred, without the opportunity for intervenors to challenge those costs, and without the procedural safeguards afforded either through a traditional rate case proceeding or through the use of a historic test year for the evaluation period in the EFRP and GFRP.

Q. CCPUG has not opposed the EFRP and GFRP as proposed by the Company, although it has proposed certain modifications, most importantly to the NOPS component of the EFRP. Would your recommendation change if the historic evaluation period is changed to a forecast evaluation period?

A. Yes. If the Council is inclined to adopt the Advisors' proposal, then I strongly recommend that the Council reject the EFRP and GFRP altogether and require the Company to file another base rate case, as it has done here, if it seeks to recover costs actually incurred in the future. The Council should retain meaningful regulatory oversight over the Company based on costs actually incurred in a historic test year that can be objectively evaluated, along with input from intervenors who have a vested interest in the outcome of rate proceedings. If the Council adopts the use of a forecast evaluation period, the Company essentially will self-direct annual rate increases with the objective of increasing its top line revenues and bottom-line earnings.

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

Q. Describe the Company's original 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.[11] The Company seeks recovery of the NOPS revenue requirement through an interim rate adjustment as specified in its proposed EFRP.

The Company proposes to make a rate filing prior to the in-service date of NOPS based on the estimated first year NOPS revenue requirement and to commence recovering the revenue requirement contemporaneous with its in-service date.

The Company provided an estimate of the first-year revenue requirement that reflected certain parameters for cost recovery. One of the proposed parameters was the use of a 30-year service life for depreciation purposes. Another parameter was to true-up the actual first year revenue requirement to the estimated first year revenue requirement. Yet another parameter was its proposal to maintain the first-year revenue requirement in all subsequent years despite the fact that the revenue requirement will decline after the first year as the plant investment is depreciated for book and tax purposes.

Q. Has the Company now modified its proposal?

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[11] Direct Testimony of Orlando Todd at 29.

A. Yes. The Company now asserts that the Council should not determine the parameters for recovery of the NOPS revenue requirement in this proceeding, but rather wait until it makes its proposed rate filing prior to the in-service date of NOPS based on the estimated first NOPS revenue requirement.[12]

Q. Should the Council defer its decision on the parameters for recovery of the NOPS revenue requirement until the Company makes its filing with the estimated parameters for recovery later this year?

A. No. the Council should reject the Company's proposal to defer the decisions on the parameters for recovery of the NOPS revenue requirement. These parameters should be addressed in this proceeding. First, the NOPS recovery is a significant component of the Company's proposed EFRP. The Company set forth it's proposed parameters for recovery in its Application and Direct Testimony, including the first-year revenue requirement, cost allocation, and revenue allocation. Thus, the parameters are at issue in this proceeding.

Second, CCPUG, Advisors, and Air Products and Chemicals, Inc. already have addressed the proposed NOPS recovery. Their testimony on these issues should not be ignored in this proceeding. The parties that addressed these issues have already expended their resources and should not be required to address the issues again when the Company files its estimated first-year revenue requirement.

Third, there is no procedural forum for CCPUG and other intervenors to

[12] Rebuttal Testimony of Joshua Thomas at 48.

address the first-year revenue requirement and other recovery issues if the Council defers the decisions regarding the parameters of the recovery. Even if there were, the Company will make its proposed first year revenue requirement filing before the end of this year, or only a month or two after the Council's order in this proceeding.

Fourth, the Company actually has not changed any of its proposed parameters for recovery. In fact, Mr. Thomas specifically states that the Company still is "seeking to confirm the mechanism by which that recovery will ultimately be accomplished" in this proceeding. Mr. Thomas also reiterated the Company's proposed parameters for recovery set forth in its Application and Direct Testimony, but specifically carved out the determination of the service life and the depreciation rate based on that service life as an issue that should be addressed in the subsequent filing for the first-year revenue requirement.[13]

Q. Did any of the Company's witnesses rebut your recommendations regarding reductions to the NOPS revenue requirement as it is depreciated for book and tax purposes, the use of a 50-year service life for depreciation purposes, and revisions to the return based on CCPUG cost of capital recommendations?

A. No. The Council should adopt the CCPUG recommendations on these issues. They are unrebutted.

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[13] *Id.*

IV. AMI RIDER

Q. Describe the Company's proposed AMI Charge.

A. The Company proposes that all AMI costs be excluded from the base revenue requirement and instead be recovered exclusively through an AMI Charge on a per metered customer basis.[14]

Q. Does CCPUG support the Company's proposed recovery of the AMI costs on a per customer or per meter basis through an AMI Charge?

A. Yes. The Company's proposal follows the fundamental principle that ratemaking recovery should be based on cost causation. The Company's proposal ensures that the actual costs are recovered on the basis they are incurred and from the customers that benefit.

Q. Do the Advisors support the proposed recovery of the AMI costs on a per metered customer basis?

A. No. The Advisors propose that the actual and forecast AMI costs be included in the base revenue requirement and that subsequent forecast costs be incorporated annually in each evaluation period under the EFRP and the GFRP.

Q. Do you oppose the Advisors' recommendation?

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[14] Direct Testimony of Joshua Thomas at 41.

A. Yes. First, it requires a forecast of AMI costs not only for the base revenue requirement, but also requires subsequent annual forecasts of AMI costs for each evaluation period under the EFRP and the GFRP. Such forecasts of future costs are not known and measurable and are subject to overstatement bias. Second, the Advisors' recommendation would improperly allocate costs on the basis of other cost allocations that are adopted in this proceeding for base rates instead of on a per metered customer basis, the causal factor in the AMI costs.

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

APRIL 26, 2019

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

LANE KOLLEN, being duly sworn, deposes and states: that the attached responses to discovery requests are true and correct to the best of his knowledge, information and belief.

Lane Kollen

Sworn to and subscribed before me on this 26th day of April 2019.

Notary Public

RANDY A. FUTRAL
MY COMMISSION EXPIRES
NOTARY PUBLIC
AUGUST 26, 2020
COBB COUNTY, GEORGIA