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July 15, 2024

BY E-MAIL

Clerk of Council
Council of the City of New Orleans
City Hall, Room IE09
1300 Perdido Street
New Orleans, LA 70112

Re: Entergy New Orleans, LLC's Formula Rate Plan Test Year 2023 Evaluation Pursuant to Council Resolution Nos. R-19-457 and R-20-344, Rider EFRP-7 and GFRP-7, Docket UD-18-07

Dear Clerk:

Please find the attached Advisors' *Investigation and Review of Entergy New Orleans, LLC's 2024 Electric and Gas Formula Rate Plan Evaluation Filings* in the above referenced matter, which we are requesting to be filed into the record along with this letter. The Advisors submit this filing electronically and will submit the requisite original and number of hard copies once the Council resumes normal operations, or as you direct.

Sincerely,

Jay Beatmann

JAB: dpm
Attachments
cc: Official Service List – Docket UD-18-07

INVESTIGATION AND REVIEW
OF
ENTERGY NEW ORLEANS, LLC'S 2024 ELECTRIC AND GAS
FORMULA RATE PLANS EVALUATION FILINGS

COUNCIL RESOLUTION NOS. R-19-457, R-20-67, R-20-112, R-20-213, R-20-268, R-20-344, R-21-295, AND R-23-491

DOCKET NO. UD-18-07

JULY 15, 2024

Legend Consulting Group Limited

Introduction

On April 30, 2024, Entergy New Orleans, LLC's ("ENO") submitted to the Council its *Entergy New Orleans, LLC's 2024 Electric and Gas Formula Rate Plan Filings* ("FRP Evaluation Filing" or "instant FRP Evaluation Filing") for the 12-month evaluation period ending December 31, 2023 ("2023 Test Year") to initiate new electric and gas rates effective with the first billing cycle of September 2024. In the FRP Evaluation Filing, ENO proposes a $7.0 million increase to its electric revenues and a $5.6 million increase to its gas revenues. The Advisors have reviewed ENO's FRP Evaluation Filing, conducted inquiry through discovery, and provide this report identifying errors in the FRP Evaluation Filing that would reduce ENO's proposed electric revenue increase by approximately $1.3 million and reduce the proposed gas revenue increase by $0.3 million, while still allowing ENO a reasonable opportunity to recover its costs and earn the Council-approved rate of return. The FRP Evaluation Filing results in a $0.69 increase[1] on the typical residential electric bill. The effect of the Advisors' corrections results in a $0.15 decrease compared to ENO's requested electric increase, which is a $0.54 increase compared to present bills. The Advisors' recommendations reduce ENO's proposed $4.20 increase on the typical residential gas bill by $0.25, which is a $3.95 increase compared to present bills. Additionally, the Advisors have identified a potential error with respect to Purchased Power Cost Recovery Rider ("PPCR") revenues and past mitigation performed through the PPCR which we were unable to resolve through discovery. The Advisors recommend that this issue be resolved during the EFRP's 35-day dispute resolution period.

Background

Prior FRP Evaluation Filings

ENO prepared its 2020 Formula Rate Plan ("FRP") evaluation reports (based on a 2019 test year), which if filed, would have requested a $32 million electric and gas total combined revenue requirement increase that, if approved, would have become effective the first billing cycle of September 2020, in the midst of the COVID-19 pandemic.

To ease the burden on ratepayers during the COVID-19 pandemic, ENO, through negotiation with the Council of the City of New Orleans ("Council"), agreed to forego a likely rate increase effective beginning September 2020 in exchange for more favorable ratemaking treatment for each of the three FRP evaluations the Council authorized in the 2018 Rate Case[2] (*e.g.*, a 51% hypothetical equity ratio), beginning in November 2021.

On July 16, 2021, ENO submitted to the Council its 2021 FRP Evaluation Filing for the 2020 Test Year. This FRP Filing was made pursuant to Council Resolution Nos. R-19-457, R-20-67, R-20-112, R-20-213, R-20-268, R-20-344, and R-21-295, wherein the Council approved ENO's Electric and Gas FRPs: Service Schedules EFRP-6 ("EFRP") and GFRP-6 ("GFRP") for electric and gas respectively and initiating new electric and gas rates effective with the first billing cycle of November 2021.

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[1] *See* the FRP Evaluation Filing, Compliance w Decoupling Bill Comparison, Bill Impacts – ENO, which presents a Legacy ENO winter-summer average typical bill (1,000 kWh/mo.) impact of $0.69.

[2] In this report, we refer to ENO's most recent rate case established by Resolution No. R-18-434 as the "2018 Rate Case".

The 2021 FRP Evaluation Filing proposed an increase in electric revenue of $40.0 million and an increase in gas revenues of $18.8 million. The 2021 FRP Evaluation Filing also included outside-the-bandwidth collections of $5.2 million in electric revenues and $0.3 million in gas revenues. Accordingly, the 2021 FRP Evaluation Filing showed an increase in revenues of $45.2 million for the electric utility and $19.1 million for the gas utility. ENO's estimated residential typical monthly bill (*i.e.*, 1,000 kWh electric and 50 ccf gas) increases according to its 2021 FRP Evaluation Filing were $11.03 and $14.21 for electric and gas respectively.

The Advisors' October 1, 2021 report identified errors in ENO's 2021 FRP Evaluation Filing totaling $14.7 million (gas and electric) as well as rate mitigation opportunities totaling $16.5 million (again, gas and electric). While ENO did not agree with the Advisors' recommendations in their 2021 report, ENO implemented EFRP and GFRP rider rates that reflected the revenues by rate class that the Advisors had recommended. ENO characterizes this as "voluntarily agreeing not to collect $14.8 million in its 2021 FRP",[3] but the $14.8 million adjustment to ENO's proposed revenue increase resulted in reasonable and appropriate rates that allowed ENO the reasonable opportunity to earn its Council-allowed Return on Equity ("ROE") of 9.35%.[4]

ENO made its 2022 FRP Evaluation Filing on April 29, 2022. That filing proposed electric and gas revenue increases of $37.0 million (including $4.7 million in agreed-to outside the bandwidth revenues) and $3.2 million respectively. The Advisors recommended downward corrections to ENO's revenue proposals of $15.7 million and $1.4 million for electric and gas respectively, plus the application of $13.9 million in available electric credits to be applied as bill mitigation measures. ENO implemented EFRP and GFRP rider rates that reflected the revenues by rate class that the Advisors had recommended, and the mitigation credits were applied to Rider PPCR.

ENO made its 2023 FRP Evaluation Filing on April 28, 2023. That filing proposed electric and gas revenue increases of $20.8 million (including $3.4 million in agreed-to outside the bandwidth revenues) and $8.2 million respectively. The Advisors recommended downward corrections to ENO's revenue proposals of $7.0 million and $1.3 million for electric and gas respectively, plus the application of $12.1 million in recommended bill mitigation measures. As part of a negotiated settlement, ENO agreed to implementing 50% of the Advisors' recommended electric corrections and all of the Advisors' recommended gas corrections. Further, the negotiated settlement implemented the Advisors' recommended bill mitigation measures with certain non-substantial adjustments.

SUMMARY OF ADVISORS REVIEW AND ADJUSTMENTS

As part of our review and as discussed later in this report, we identified errors in the instant FRP Evaluation Filing and prepared what we refer to as Advisor Adjustments to correct them. If these Advisor Adjustments are agreed to by the Parties, they would result in a reduction to the ENO proposed increases of approximately $1.3 million for the electric utility and $0.3 million for the gas utility.

Table 1 presents a summary of the total proposed revenue impacts of the FRP Evaluation Filing, Advisor Adjustments and the net FRP revenue impact.

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3 FRP Evaluation Filing, Summary Pleading at 4.

4 *See* Investigation and Review of Entergy New Orleans LLC's 2022 Electric and Gas Formula Rate Plans Evaluation Filings, "ENO's 2021 Financial Performance" at 6-7.

Table 1 Summary of Advisor Recommended Adjustments ($ in Millions)		
	Electric	Gas
ENO Proposed FRP Revenue Increase	**$ 7.0**	**$ 5.6**
Advisor Adjustments to Evaluation Report	($ 1.3)	($ 0.3)
Revenue Increase After Advisor Adjustments	**$ 5.7**	**$ 5.3**
Percent Change to ENO's Proposed Revenue Increase	(18.3%)	(6.1%)
Notes: The issue with regard to Rider PPCR revenues and the effects of past mitigation performed through Rider PPCR, discussed later in this report, must be resolved and could significantly impact the appropriate revenues.		

In addition to these Advisor Adjustments, our report also discusses the allocation of electric revenue requirement (decoupling) among the rate classes pursuant to Rider EFRP Section II.B.2 and other items for Council consideration that we have identified during our investigation and review.

ENO'S FRP EVALUATION FILING

ENO's FRP Evaluation Filing proposes both an electric and a gas FRP revenue increase, and ENO has requested FRP rate adjustments to prospectively (*i.e.*, commencing with the first billing cycle of September 2024) reset each of its electric and gas rates consistent with the FRPs' midpoint ROE of 9.35%. As discussed later in this report, decoupling is a required element of the EFRP Evaluation filing, and the decoupling mechanism is utilized in determining customer class revenue requirement allocations in each test year FRP Evaluation report.

Table 2 presents the as-filed FRP Evaluation Filing electric revenue change by rate class.[5]

[5] Table 2 summarizes ENO's decoupling results provided in Attachment G, and the supplemental workpapers supporting Compliance with Decoupling.

Table 2 ENO FRP Evaluation Filing Change in Electric FRP Revenues			
Rate Class	Applicable Base Revenue	Proposed Change in FRP Revenue	Proposed Change in FRP Revenue as Percent of Base Revenue
Residential	$ 186,464,277	$ 1,599,432	0.9%
Small Electric Service	73,390,826	5,277,971	7.2%
Municipal Buildings	2,623,553	274,985	10.5%
Large Electric	26,019,619	187,452	0.7%
Large Electric High Load Factor	96,561,783	1,517,862	1.6%
Master Metered Non-Residential	571,436	48,151	8.4%
High Voltage	5,702,594	83,638	1.5%
Large Interruptible	4,046,306	(680,965)	(16.8%)
Lighting Service	4,051,692	(1,274,653)	(31.5%)
Total	$ 399,432,085	$ 7,033,874	1.8%

Table 3 presents ENO's as-filed proposed Gas FRP revenue increases.

Table 3 ENO's Proposed Gas Change in FRP Revenues			
Rate Class	Applicable Base Revenue	Proposed Change in FRP Revenue	Proposed Change in FRP Revenue as Percent of Base Revenue
Residential	$ 22,894,894	$ 3,587,326	15.7%
Small General	5,122,252	802,589	15.7%
Large General	5,538,551	867,817	15.7%
Small Municipal	47,743	7,481	15.7%
Large Municipal	2,425,719	380,078	15.7%
Total	$ 36,029,159	$ 5,645,292	15.7%

Earned Rate of Return

ENO's FRP Evaluation Filing reports an Earned Return on Common Equity ("EROE").[6] ENO's stated electric EROE is 8.66%, and ENO's stated gas EROE is 5.87%.[7] Per the FRP riders' bandwidth of +/- 50 bp,[8] when ENO's gas or electric EROE falls below 8.85%, an upward adjustment to ENO's FRP rate is required to allow ENO the reasonable opportunity to earn its allowed ROE of 9.35%.

6 *See* Evaluation Filing Attachment B at 1.

7 *Id*.

8 *See* Rider EFRP-7 and GFRP-7, each, Section II.C.1.g.

After applying the Advisor Adjustments to correct for identified errors in the FRP Evaluation, but not adjusting for certain unresolved issues related to revenues from Rider PPCR, ENO's electric EROE is 8.78%, and ENO's gas EROE is 6.09%.

Both of these Advisor-adjusted EROE values are below 8.85%, and therefore we have calculated FRP rate adjustments for each of gas and electric to allow ENO the reasonable opportunity to earn an EROE of 9.35%. We note that ENO's Advisor-adjusted electric EROE of 8.78% is close to the bandwidth threshold of 8.85%, the point at which no electric FRP rate adjustment would be provided for per Rider EFRP-7.

Comparative calculations of ENO's electric and gas EROEs between those filed by ENO and those calculated by the Advisors is provided as Attachment D to this report.

Proposed Decreases to Lighting Service and Large Interruptible Revenues

Production and transmission costs of service have been allocated to the various customer classes based on each of their contributions coincident with ENO's 12 monthly peak demands. This development of each customer class responsibility towards the recovery of production and transmission costs is not a singular calculation, but rather involves consistent recognition of the nature of the costs and the allocation methods. Specifically, the Lighting class of service annual average use has been 51,540 MWh since the rate case, including 47,107 MWh in the 2023 test period. And since the 2018 Rate Case, the Lighting class of service has been allocated responsibility towards the recovery of production and transmission costs based on an average 2,348 MW contribution coincident with ENO's 12 monthly peaks, not including the 2023 test year. In 2023, all of ENO's 12 monthly peaks occurred during hours not requiring lighting, the first year of this unusual occurrence since the 2018 Rate Case. Using this singular test year and allocation method would result in the lighting class of service having no cost responsibility for production and transmission capital costs and operating and maintenance expenses. Applying the same decoupling rate of return on rate base for the lighting class of service as in the 2023 EFRP, with this significant reduction in cost allocation, resulted in ENO's Evaluation Filing showing a 31.5% reduction in Electric FRP Revenues for the Lighting class of service. As explained further herein, the Advisors developed a cost allocation with more consistency, which addresses this issue.

The LIS class of service consists of one large customer whose demands applicable for cost allocation may not be as consistent over time compared to other large customer classes with many customers. In the last four EFRP Evaluation Filings, ENO has made the following decoupling proposals for changes to LIS base revenue: 2024 EFRP 16.8% decrease; 2023 EFRP 12% increase; 2022 EFRP 14% decrease; and 2021 EFRP 31% increase. To address the variability of results for the LIS class of service, the Advisors have used a cost allocation with more consistency and reasonable changes to rates of return, proposing a 4.5% increase to LIS present revenue.

Typical Bill Impact

ENO's estimate of electric and gas typical bill impacts from its electric FRP Evaluation Filing and Gas FRP Evaluation Filing are presented in Tables 4 and 5. Of note, the bill impacts are incremental from the EFRP and GFRP rates presently in effect.

Table 4 **ENO FRP Evaluation Filing Estimated Change to Typical Electric (Legacy) Customer Monthly Bill**					
Rate Class	Typical Energy (kWh)	Typical Demand (kW)	Present	Proposed	Change
Residential[1]	1,000	-	$ 140.56	$ 141.25	$ 0.69
Small Electric	9,125	50	$ 1,421.59	$ 1,489.03	$ 67.44
Large Electric	91,250	250	$ 10,714.94	$ 10,707.64	($ 7.30)
1. ENO's presented residential typical bills are calculated using a simple average of summer and winter typical bills (in both cases, 1,000 kWh/mo.).					

Table 5 **ENO Proposed Estimated Change to Typical Gas Customer Monthly Bill**				
Rate Class	Typical Usage	Present	Proposed	Change
Residential	50 ccf	$ 61.59	$ 65.79	$ 4.20
Small General	500 ccf	$ 475.23	$ 503.72	$ 28.49
Large General	1,000 mcf	$ 7,937.22	$8,356.78	$ 419.56

ADVISOR REVIEW OF THE FRP EVALUATION FILING

The Advisors have, during the FRP's prescribed 75-day review period, reviewed ENO's FRP Evaluation Filing to ensure that it complies with the requirements of the FRP Tariff (specifically Section II.C of the FRP riders). The Advisors are directed to identify and formally communicate in writing to ENO and/or other Parties any identified errors in the application of the principles and procedures set forth in the annual redetermination of Rate Adjustments.

In the conduct of our investigation and examination of the FRP Evaluation Filing we: (i) reviewed ENO's FRP Evaluation Filing and associated work papers; (ii) issued six sets of discovery to ENO consisting of 50 single and multi-part questions; (iii) reviewed and analyzed all discovery responses; and (iv) reviewed ENO's FERC Form 1 filings, Entergy Corp.'s SEC 10-K filings, and other informational filings.

Our investigation, review, and examination of ENO's FRP Evaluation Filing focused on:

1) Review of ENO's reported revenue amounts and consideration of their reasonable predictive value for revenues ENO may earn during the rate-effective period (*i.e.*, September 2024-August 2025);
2) adherence to the EFRP-7 and GFRP-7 tariffs, including those riders' provisions for known and measurable adjustments to revenues or cost of providing utility service;
3) adherence to sound ratemaking principles, especially those applied precedentially by the Council in the 2018 Rate Case; and

4) certain of ENO's ratemaking proposals that exceed the Council's customary past ratemaking treatment.

Our review identified several adjustments to ENO's proposed FRP revenues. Table 6 presents the Advisor Adjustments. While we believe the estimates are accurate, ENO employs an array of proprietary and licensed (*i.e.*, not readily available to the public) software tools to generate the schedules and attachments to its FRP Evaluation Filing, including tools such as Utilities International's UI Planner software, which appears to be the basis of ENO's Plan to Results (P2R) regulatory filing system. Further, ENO uses licensed software such as Power Plan and Power Tax for key revenue requirement inputs. As such, ENO's final compliance calculations may differ somewhat from the revenue impacts summarized in Table 6 below.

Table 6
Summary of Advisor Adjustments
($ Millions)

Description	*Electric*	*Gas*	*Total Company*
ENO Proposed Incremental FRP Revenues	**$ 7.03**	**$ 5.65**	**$ 12.68**
Advisor Adjustments			
ADV01 – Rider Revenues	($ 0.05)	($ 0.35)	($ 0.40)
ADV03 – LCFC	($ 0.87)	-	($ 0.87)
ADV04 – Storm Proforma	($ 0.29)	-	($ 0.29)
ADV05 – FIN 48 Interest	$ 0.02	$ 0.0	$ 0.02
ADV06 – FIN 48 ADIT	($ 0.09)	-	($ 0.09)
Total – Advisor Adjustments	**($ 1.29)**	**($ 0.34)**	**($ 1.63)**
Total Advisor Adjusted FRP Revenue Change	**$ 5.74**	**$ 5.30**	**$ 11.05**
Note: Values do not sum due to rounding.			

Advisor Adjustments

Here, we discuss each Advisor Adjustment regarding identified errors in the FRP Evaluation Filing. These Advisor Adjustments are enumerated as "ADVXX". Additionally, for each Advisor Adjustment, the specific adjustment dollar amount by ENO Account is detailed in Attachment C to this report.

Rate Schedule and Other Revenues Adjustment (ADV01)

ENO describes Adjustment AJ01A as an "[a]djustment to annualize and synchronize Rate Schedule Revenues and Riders, reclassify certain Rate Schedule Revenues to Other Electric Revenue, and remove interdepartmental sales and unbilled revenues." While the Advisors confirmed ENO's annualization of FRP revenues and reclassification of certain rate schedule revenues[9] to be appropriate, with the minor exceptions noted below, ENO's adjustment to "synchronize" test period revenues is contrary to Council directives and industry best practices related to development of a test year cost of service. In Resolution R-19-457, the Council approved the FRP mechanisms and directed that the total utility cost of service include total ENO revenues

[9] Reclassification of certain rate schedule revenues include revenues to Other Electric Revenue, removal of interdepartmental sales, and unbilled revenues.

and expenses[10] and further that, "The revenue deficiencies/excesses shall be determined for each customer class by comparing the E-FRP customer class total revenue requirements with the customer class evaluation period total actual revenues,"[11] (Emphasis added.) The Advisors' investigation, review and examination of ENO's 2021, 2022 and 2023 Evaluation Filings focused on, among other issues, validation of ENO's reported test year revenue amounts, and the correlation of the FRP revenues with ENO's FERC Form 1 filings, Entergy Corp.'s SEC 10-K filings, and other informational filings.[12] Based on these Council directives, the EFRP revenue increase is the difference between the proposed estimated revenues, subject to evaluation, and the revenues ENO collected in the test year, or would have collected had the present rates (*e.g.*, FRP rates) been in effect for all of the test year.

However, in the FRP Evaluation Filing, ENO replaced test year reported revenue by setting current test year rider revenue equal to rider expenses, such that the revenue credit to the test year cost of service was not the actual rider revenues collected. This step of replacing actual test year revenues ignores the long-held industry regulatory concept of first developing a test year total cost of service, which then provides the basis for subsequent evaluation of cost recovery through rate design.[13] Developing a revenue requirement and revenue deficiency/excess from a cost of service analysis does not include inserting a guaranteed revenue collection based on a rider design. Guaranteed revenue in the regulatory process, or an assurance of "exact cost recovery," is not the nature of FRP rates, and it is not a regulatory concept specifically approved by the Council for FRP purposes.

Based on the detail provided in discovery responses, the Advisors confirmed the reported test year base rate revenues and each rider per book revenue for each of the customer classes, as well as the various other operating revenues. The Advisors' ADV01 adjustment consists of reversing ENO's "Exact Recovery of Expense" adjustment[14] for each of the riders to restore test year per book values as the appropriate present revenue credit to the test year cost of service/ revenue requirement.

The individual electric revenue credit adjustments we make in ADV01 are, $536,731 fuel (FAC), $21,836 EECR, $ 31,966 MISO, and ($538,873) PPCR for a total increase to ENO's present revenue (*i.e.*, reduction to ENO's revenue deficiency) of $51,661. The negative PPCR revenue credit adjustment is pending, as we were unable to resolve an issue with PPCR revenues through

10 *See* Council Resolution No. R-19-457, Directive 25. a.

11 Council Resolution No. R-19-457, Directive 26.

12 Related to the analysis of test year reported revenue and monthly rider filings, the Advisors issued the following Data Requests: CNO 1-2a, 1-31, 2-1, 2-19, and 3-8 in the 2021 FRP; CNO 1-2, 2-6, and 2-9 in the 2022 FRP; CNO 1-6 and 1-23 in the 2023 FRP, and CNO 1-14, 4-5, 4-6, 4-7, and 5-2 in the 2024 FRP.

13 The basic steps include: development of the test period total utility revenue collected from all sources; calculation of the test period revenue requirement from all sources; cost allocation to each customer class; and design of rates, including consideration of the effectiveness in yielding total revenue requirements. NARUC Cost Allocation Manual, 1992. P.13 & 24.

"The auditor should begin by looking at an analysis of the test year revenues…" NARUC Rate Case and Audit Manual 2003. P31.

"Cost allocation typically occurs after a cost of service study, which determines the utility's revenue requirement, and before rate design, which determines what and how customers will be charged." Cost of Service -> Cost allocation -> Rate Design. Emerging Trends in Utility Cost Allocation. Pacific Northwest National Laboratory. May 1922. P3-4.

14 It was necessary for ENO to support the source of expenses used in the "Exact Recovery of Expense" adjustments made to per book revenue. See DRs CNO 4-7, 5-2, 6-1, and 6-2.

discovery.[15] The issue with regard to the PPCR revenue credit to ENO's cost of service and the effects of past mitigation performed through the PPCR, discussed later in this report, must be resolved and could significantly impact the appropriate revenues in the FRP Evaluation.

Of note, the test year 12 monthly PPCR filings indicated a PPCR cost recovery total of $21,001,847, including Council mitigation of ($12,488,424) implemented through the PPCR Rider, for a <u>net</u> PPCR recovery from ratepayers of $8,513,423. This net PPCR cost recovery amount was compared to the test year PPCR per book revenue of $9,083,200, which includes mitigation. ENO's "Exact Recovery of Expense" adjusted the PPCR revenue credit to $9,619,687; ENO derived that expense-based amount from PPCR 12-month costs of $19,946,476, net of two offsets: ($7,344,027), identified as a capacity deferral, and a Council approved mitigation of ($2,982,761) related to a NOX deferred expense credited against PPCR cost recovery in the May 2023 PPCR Filing.[16] Based on our review of the relevant discovery responses, it appeared that the capacity deferral offset is related to the sum of test period monthly PPCR over/under balances. The other PPCR test period costs offset of ($2,982,760) related to a NOX deferred expense originating in 2022, but there was insufficient data to confirm ENO's applying that mitigation to its PPCR "Exact Recovery of Expense" adjustment. Although we related test period PPCR revenue excluding mitigation (approximately $21 million) to total test period PPCR costs (also approximately $21 million), we were unable to resolve issues involving ENO's PPCR expense-based proforma revenue credit, despite the analysis of several discovery responses and supporting data in the EFRP Evaluation. Until these issues are resolved, we applied Advisors' Adjustment uniformly to all Riders, recognizing that the ($538,873) PPCR revenue credit adjustment represents an increase to ENO's cost of service/revenue requirement. The implementation of the Council's mitigation in the PPCR, and in the development of the revenue requirement and associated cost allocation among customer classes is pending clarification during the EFRP required 35-day dispute resolution period following this report.

Similarly, the Advisors' ADV01 adjustment for gas reverses ENO's "Exact Recovery of Expense" adjustment related to the PGA rider, but also corrected an error in reclassifying a miscellaneous services revenue. The adjustment to gas total operating revenues as a credit to the test year cost of service/ revenue requirement was $348,714.

LCFC (ADV03)

In Resolution R-20-51, the Council noted that an adjustment to prospective billing determinants corresponding to the approved savings goals will be implemented in determining the FRP revenue requirement.[17] In the LCFC discussion in the 2018 general rate case, ENO's proposal advocated LCFC recovery based on actual results.[18] The use of the actual recent year Energy Smart program kWh reductions compared to the kWh Savings goal included in the Energy Smart three-year Implementation Plan provides a more certain estimate for determining a LCFC adjustment. The EFRP tariff requires, "In calculating the LCFC adjustment, ENOL shall use the most current actual

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15 *See* DRs CNO 5-2 and 6-2.

16 Allowance credit approved per 4/27/23 letter from Utility Committee Chair.

17 Resolution R-20-51, p. 27-28.

18 See Resolution R-19-457, page 156.

data and not the kWh savings goals included in the approved Energy Smart Implementation Plan."[19]

ENO did utilize actual data in calculating its LCFC adjustment, using the three-year average of the percent of Energy Smart kWh savings goal that was achieved (program years 2020 through 2022), and applying that average percent to the program year 2024 approved kWh savings goal. However, Energy Smart Program 2023 kWh savings data are now available. Based on a review of the trend in Energy Smart kWh savings achieved over the 2020-2023 period, the Advisors believe that ENO's LCFC adjustment is overstated and that the most current actual data for the three-year period 2021 through 2023 more appropriately represents expectations of Energy Smart kWh savings and the associated lost contributions to fixed costs.

Accordingly, the Advisors have adjusted ENO's LCFC proforma amount to a more reasonable expectation of ENO's ability to achieve its Energy Smart kWh goals by applying a factor based on actual results from the three most recent program year (2021 through 2023). This adjustment is made as Advisor Adjustment ADV03.

Notwithstanding the use of a reliable current estimate of LCFC in the EFRP, prospectively there will be a true-up to actual LCFC costs through Rider EECR.[20] The LCFC true up for this 2024 pro-forma estimate will be included in the EECR Filing mid-year 2025, for recovery in EECR rates effective for calendar year 2026.

Proforma Storm Capital Investments (ADV04)

The FRP riders allow ENO to proform costs into its cost of service related to the year following the test year (*i.e.*, 2024 for the instant FRP Evaluation Filing). Rider Schedule EFRP-7 (electric) says,

> For purposes of this Rider EFRP, adjustments for changes to Rate Base, Revenues, and Expense for the prospective twelve months following the EFRP evaluation period (*i.e.,* Proforma Adjustments) can be made as long as they are "Known and Measurable." Known and Measurable changes, including attendant impacts, are those changes that reflect changes in operating conditions and/or costs incremental to test year evaluation period operations. Such costs must be expected to be incurred and reasonably budgeted with sufficient information to be verified as appropriate proforma adjustments as set forth in Attachment H.[21]

ENO has requested a $2,418,864[22] proforma addition to distribution plant in service related to storm restoration capital costs that may be incurred in 2024 with respect to minor weather events. As with ENO's 2023 FRP Evaluation Filing, ENO errs in proposing this proforma adjustment because these estimated investment amounts do not meet the "known and measurable" standard for inclusion in the FRP Evaluation's cost of service.

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19 Rate Schedule EFRP-7, Attachment H, B.

20 Resolution R-23-491, at 5.

21 Rider Schedule EFRP-7, FN 1 at pg. 30.3.

22 *See* FRP Evaluation Filing, Attachment H (electric), funding project "F1PCDSTR0N: DISTR STORM DAMAGE CAPITAL, ENOI".

As such, consistent with our recommendations in our 2023 report, ENO erred in proposing the proforma adjustment to add $2,418,864 to its plant in service. Advisor Adjustment ADV04 corrects this error by removing this proforma and its related ratemaking effects.

Interest on FIN 48 Tax Liabilities (ADV05)

In ENO's Adjustment AJ06B, ENO requests recovery of ($18,968) electric (a credit or negative expense) and ($3,832) gas (also a credit or negative expense)[23] in calculated interest on tax positions that in ENO's opinion do not meet the "more-likely-than-not recognition threshold"[24] of being allowed by the IRS upon audit (*i.e.*, FIN 48 tax positions).[25] In prior FRP Evaluations, ENO has requested a debit or positive FIN 48 expense. In the instant FRP Evaluation Filing, ENO has calculated credit or negative expenses based on reversal of FIN 48 liabilities related to the completion of its 2016 through 2018 IRS Audit in December 2023.[26] ENO has erred in the same fashion as in prior FRP Evaluations, but in this case in ratepayers' favor. Still, it is appropriate to correct ENO's error. We have corrected ENO's error regarding FIN 48 interest by reversing these electric and gas (negative) expenses through Advisor Adjustment ADV05.

FIN 48 ADIT (ADV06)

Accepted ratemaking principles[27] as well as precedential Council directives[28] require that temporary timing differences (recognized as ADIT) be reflected in rate base, regardless of their degree of uncertainty of being upheld by the IRS (*i.e.*, regardless of their status under FIN 48). As such, ENO erred by excluding a total of $1,018,003 in FIN 48 ADIT from its rate base.[29] The Advisors have reversed this inappropriate exclusion through Advisor Adjustment ADV06.

Cost Allocation/Customer Class Decoupling Adjustments

While the methods of cost allocation used in the 2018 Rate Case are to be maintained throughout the EFRP Evaluation Filings, updating external allocation factors consistently with a complete supporting analysis is necessary to maintain fairness in the customer class decoupling revenue adjustments. Ordering Paragraph 14 of Resolution R-19-457 stated that the utility's total revenue requirements, as determined by compliance with each of the Council's directives in this Resolution, will be recovered from each customer class on the basis of the Advisors' proposal for customer class revenue requirements as indicated in Advisors' Exhibits VP-20 and VP-21 in Council Docket No. UD-18-07 for the electric and gas utilities respectively. Also, Rider EFRP Tariff Sec. II.B.2 states that the determination of the fixed and variable revenue requirements by rate class shall be consistent with the allocation methodologies approved in Docket UD-18-07 except that the return on rate base component shall be based on class rates of return corresponding to the relative rate

23 *See* ENO's response to DR CNO 5-1.

24 *See* FASB Interpretation No. 48 at 5.

25 *See* ENO's response to DR CNO 3-1.

26 *See* ENO's response to DR CNO 5-1.

27 *See e.g.*, FERC Opinion No. 581 (181 FERC ¶ 61,243) at 322 ("Coupling the Commission's tax normalization policy with FIN 48 requires that all uncertain tax positions taken in a given tax year, regardless of their level of certainty, shall be recognized in the proper ADIT accounts and appropriately included in rate base. ").

28 *See* Council Resolution No. R-19-453, Ordering Paragraph 4 ("ENO's proposal to exclude FIN 48 ADIT liability balances from its rate bases is denied.").

29 *See* ENO's response to DR CNO 3-4.b.i ("FIN 48 ADIT of $734,437 and $283,566 was excluded from the per book amounts in accounts 283225 - Section 475 Adjustment-Fed and 283226 -Section 475 Adjustment-St.").

class revenues set in Docket UD-18-07. Consistency with allocation methodologies would include a rigorous examination of how each allocation factor is derived, because of the impacts that allocation factor values have on decoupling results.

The Advisors' examination of the capacity-related fixed cost allocation factors included in the 2024 EFRP raised some questions when compared to the comparable allocation factors developed in the recent 2018 Rate Case and the several EFRP filings thereafter.

Residential monthly usage since the 2018 test period has been relatively consistent, averaging 1,128 kWh/customer, with only minor variation in each EFRP evaluation. Yet, based on the data in the EFRP filings, the estimated Residential customer class ratio of monthly average to 12 coincident peak (load factor) has varied significantly during this recent period due to the differences in the estimates of Residential peak demands. Specifically, the estimated residential class average to peak demand monthly load factors have ranged from 62.6% to 50.4%, with 58.9% estimated for the 2024 EFRP. This range of EFRP estimated residential load factors, when compared to a relatively stable residential average monthly usage, would infer that EFRP test period estimates of Residential coincident peak demands since the rate case require more supporting analysis regarding consistency, considering the corresponding impacts on cost allocation factors and customer class cost of service results.

Residential capacity-related cost allocation factors have been estimated, and small variations in the estimates result in significant changes to the allocated residential cost of service. That estimation has required the use of load research data, with sampled results of a small group applied statistically to the entire residential customer class. We note that since ENO's full implementation of AMI, no AMI meter data has been used to provide residential class demands at the required specific hours. (The application of AMI meter data in developing ENO customer hourly and peak data is discussed further in a following section.) In each of the recent EFRP filings, the Advisors requested that ENO provide the load research data which supports all estimation and derivations of demands used for allocating costs, and provide a worksheet which applies such load research data to develop the monthly coincident peak demands, maximum diversified demands, and non-coincident customer peak demands by rate class. ENO responded that the Company does not have worksheets applying raw load research data to estimate demands because such analysis occurs within the load research analytics system.[30] Since ENO did not provide any worksheets to support the capacity-related fixed cost allocation factors for the FRP Evaluation periods, the Advisors constructed an alternative approach which combined the capacity-related fixed cost allocation factors from available ENO data for EFRPs since the rate case. The kW peak demands from each of the EFRP test periods were combined for each of the nine customer classes resulting in weighted capacity-related fixed cost allocation factors which were used in the Advisors' decoupling analysis.[31]

The Advisors proposed this alternate approach, given (i) the use of load research sample data to estimate monthly peak demands, coupled with the inability to compare to load research sample data used in, and since, the rate case, (ii) the variability of the demand estimates since the rate case,

[30] 2022 FRP DRs CNO 4-13 and CNO 4-14; 2023 FRP DR CNO 3-5; and 2024 FRP DR CNO 5-2

[31] "Changes in technology and regulation necessitate a change in cost allocation process. Utility regulators should embrace a flexible approach for allocating costs." Emerging Trends in Utility Cost Allocation. Pacific Northwest National Laboratory 2022, p.6.

and (iii) that ENO has not used AMI hourly data to confirm the peak demands used for allocation of fixed costs, despite that hourly AMI data is available from 99.6% of ENO customers.

Rider EFRP-7 provides that rate classes Master Metered Non-Residential, Large Electric High Voltage and Large Interruptible Service shall have a decoupling revenue adjustment cap of 10%, provided that the total electric utility FRP revenue adjustment for that evaluation does not exceed 10%.[32] With the Advisors' proposed change in total EFRP revenue, (see Table 2) that decoupling revenue adjustment cap was not exceeded for those three customer classes.

The comparative results of electric rate class revenue and corresponding rates of return are presented herein in the following Attachments, Attachment A, page 1, which presents the results of the Advisors' 2018 Rate Case Recommended Electric Revenue Requirements by Rate Class; Attachment A, page 2 which presents ENO's current decoupling compliance with Rider EFRP's tariff; and Attachment B, which presents the Advisors' Adjusted Revenue Requirement and Decoupling analysis for the EFRP Evaluation Period. In comparing Attachment A and Attachment B, the Advisors' application of decoupling results in an equitable EFRP percent revenue changes among the customer classes, as well as adjustments to customer class rates of return.

The Advisors' decoupling analysis also noted a potential issue related to determining the customer class revenue requirements, which are to include a test period evaluation of total operating expenses and the corresponding revenues related to their recovery. Specifically, to determine the customer class revenue requirements upon which to base the customer class decoupling revenue adjustment and EFRP rate adjustment, the total allocated cost of service is credited with operating revenue by customer class, including test period revenue from the PPCR Rider, all other riders, and other non-tariff operating revenue. The PPCR Rider was also used to apply mitigation revenue credits related to the 2023 EFRP final revenue adjustment as well as a May 2023 one-time credit of $3.0 million.[33] However, mitigation credits applied through the PPCR Rider should not be used as an offset in determining test period PPCR revenue associated with recovering PPCR costs by rate class. Only the customer class PPCR Rider revenue directly associated with PPCR cost recovery should be applied as a credit to the allocated cost of service. Specifically, the PPCR Rider revenue credit should not include mitigation revenue credits that are not associated with the recovery of purchased power costs. To address this potential issue with a more supportable basis for the PPCR revenue credit to ENO's cost of service, the Advisors referenced the PPCR costs and revenues in the 2023 monthly PPCR filing workpapers to identify PPCR test period revenue by customer class in which revenue mitigation was not included. Based on this review, the Advisors were not able to correlate the PPCR revenue credit with ENO's proforma adjustment to PPCR revenue, which was derived from expenses and based on an exact recovery of expenses. As mentioned in the discussion of Advisor Adjustment ADV01 above, this potential issue should be clarified with possible discussion with ENO. The issue with regard to PPCR revenues and the effects of past mitigation performed through the PPCR could significantly impact the appropriate revenue adjustment in the FRP Evaluation.

Rider BRAR

As part of the FRP Evaluation Filing, ENO has recalculated rates for its Base Rate Adjustment Rider ("BRAR"), whose purpose is to credit Residential Algiers electric rates and charge large and

32 *See* Rider EFRP-7, Section II.C.3.

33 *See May PPCR* letter from UCTTC Chair Mr. JP Morell to Ms. Courtney Nicholson, April 27, 2023.

industrial customers to pay for this credit. The present BRAR rate credits Algiers Residential customers 5.929% of their base rate at a cost to large and industrial customers of approximately $1.4 million per year. This 5.929% BRAR rate equates to a $5.10 Algiers Residential typical bill credit (1,000 kWh/mo. Summer/Winter average). The proposed BRAR rate is a credit of 0.731% at a cost to large and industrial customers of approximately $0.2 million. This 0.731% proposed BRAR rate equates to a $0.63 Algiers Residential typical bill credit (1,000 kWh/mo. Summer/Winter average). This proposed change to BRAR rates is provided for by Council Resolution No. R-19-457,[34] and our review of ENO's calculation indicates that it complies with the Council's direction.

The amount of any BRAR rate change is dependent on the change in the residential FRP revenue requirement. Specifically, Algiers residential rates are allowed to increase up to 4%, including the effect of a reduction in BRAR rates (a reduction in BRAR rates increases the Residential Algiers total rate). Whenever residential rates increase by less than 4% as part of a FRP Evaluation, BRAR rates may decrease to cause an overall 4% increase in Algiers Residential rates.

Once ENO calculates its final FRP rates based on any agreed-to adjustments, changes to various allocations, and class rates of return, ENO should also recalculate BRAR rates, which we note could thereby be zero, effectively retiring Rider BRAR. Of note, the electric Franchise Tax rate for Algiers is 2.0%, while the electric Franchise Tax rate for the remainder of New Orleans is 5.0%.[35] As such, total electric bills in Algiers will remain somewhat lower than in the remainder of New Orleans even should Rider BRAR be retired.

Proforma Adjustments No Longer Required

Prior FRP Evaluation filings contained errors requiring Advisor Adjustments which are not required in the instant FRP Evaluation. Through settlement agreements between the Council and ENO or changes in ENO's circumstances, certain Advisor Adjustments that we recommended in prior FRP Evaluations are no longer required or recommended in the instant FRP Evaluation.

OPEB

In our review of ENO's 2023 FRP Evaluation Filing, we recommended an expense credit totaling $3.41 million for gas and electric related to ENO's proforma exclusion of Other Post-Retirement Benefits ("OPEB") expense credits from its cost of service. This adjustment was appropriate because there was no mechanism to prevent ENO from capturing these negative expenses once the external trust related to OPEB was terminated.

Through negotiations between ENO and the Council in the extension of ENO's FRP, it was agreed that going forward, ENO would be allowed to exclude OPEB expenses from its cost of service, but that ratepayers would have a claim on the external trust related to these negative expenses upon that trust's termination.[36] Upon review of the instant FRP Evaluation Filing, ENO has complied with this agreed-to treatment, and no Advisor Adjustments are required.

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34 *See* Council Resolution No. R-19-457 at 77 ("Starting in 2021 with rates effective with that year's FRP evaluation, Algiers residential revenue will increase by a minimum of 4%, or equal to the residential class revenue increase when greater than 4%, until parity is achieved with the remainder of the residential rate class.") We note that this language is part of the resolution's "whereas" language but is nonetheless stated as a finding by the Council.

35 The gas Franchise Tax rate is 5.0% for all of New Orleans.

36 *See* Council Resolution No. R-23-491 at 4.

RATEPAYER IMPACT OF ENO'S FRP EVALUATION FILING AS ADJUSTED BY ADVISORS

The below Table 8 presents FRP revenue increases after applying the Advisor Adjustments to correct for the errors we identified in the FRP Evaluation Filing including our recommended bill mitigation measures. Table 2, which presents ENO's proposed change in FRP revenue is reproduced for comparison.

Table 2
(reproduced from above)
ENO FRP Evaluation Filing Change in Electric FRP Revenues

Rate Class	Applicable Base Revenue	Proposed Change in FRP Revenue	Proposed Change in FRP Revenue as Percent of Base Revenue
Residential	$ 186,464,277	$ 1,599,432	0.9%
Small Electric Service	73,390,826	5,277,971	7.2%
Municipal Buildings	2,623,553	274,985	10.5%
Large Electric	26,019,619	187,452	0.7%
Large Electric High Load Factor	96,561,783	1,517,862	1.6%
Master Metered Non-Residential	571,436	48,151	8.4%
High Voltage	5,702,594	83,638	1.5%
Large Interruptible	4,046,306	(680,965)	(16.8%)
Lighting Service	4,051,692	(1,274,653)	(31.5%)
Total	$ 399,432,085	$ 7,033,874	1.8%

Table 8
Advisor Adjusted Electric Change in FRP Revenues

Rate Class	Applicable Base Revenue	Advisor Adjusted Change in EFRP Revenue	Adjusted Change in EFRP Revenue as Percent of Applicable Base Revenue
Residential	$ 186,464,277	$ 1,248,394	0.67%
Small Electric Service	73,390,826	170,028	0.23%
Municipal Buildings	2,623,553	6,370	0.24%
Large Electric	26,019,619	1,466,607	5.64%
Large Electric High Load Factor	96,561,783	2,208,824	2.29%
Master Metered Non-Residential	571,436	1,493	0.26%
High Voltage	5,702,594	175,797	3.08%
Large Interruptible	4,046,306	285,540	7.06%
Lighting Service	4,051,692	185,596	4.58%
Total	$ 399,432,085	$ 5,748,647	1.44%

Likewise for gas, Table 9 presents ENO's proposed GFRP revenue increases to the GFRP revenue increases after applying the Advisor Adjustments. Table 3, which presents ENO's proposed change in GFRP revenue is reproduced for comparison.

Table 3
(reproduced from above)
ENO's Proposed Gas Change in FRP Revenues

Rate Class	Applicable Base Revenue	Proposed Change in FRP Revenue	Proposed Change in FRP Revenue as Percent of Base Revenue
Residential	$ 22,894,894	$ 3,587,326	15.7%
Small General	5,122,252	802,589	15.7%
Large General	5,538,551	867,817	15.7%
Small Municipal	47,743	7,481	15.7%
Large Municipal	2,425,719	380,078	15.7%
Total	$ 36,029,159	$ 5,645,292	15.7%

Table 9
Advisor Adjusted Gas Change in FRP Revenues

Rate Class	Applicable Base Revenue	Advisor Adjusted Change in GFRP Revenue	Adjusted Change in GFRP Revenue as Percent of Applicable Base Revenue
Residential	$ 22,894,894	$ 3,368,170	14.7%
Small General	5,122,252	753,557	14.7%
Large General	5,538,551	814,801	14.7%
Small Municipal	47,743	7,024	14.7%
Large Municipal	2,425,719	356,858	14.7%
Total	$ 36,029,159	$ 5,300,410	14.7%

Applying the Advisor Adjustments and bill mitigation measures results in estimated changes to typical bills as indicated in Table 10 and Table 11 below.

Table 10
Estimated Change to
Typical Electric (Legacy) Customer Monthly Bill

Rate Class	Energy (kWh)	Present	ENO Proposal	After Advisor Adjustments and Bill Mitigation Measures	Change from ENO Proposal
Residential	1,000	$ 140.56	$ 141.25	$ 141.10	($ 0.15)
Small Electric	9,125	$ 1,421.59	$ 1,489.03	$ 1,423.77	($ 65.26)
Large Electric	91,250	$ 10,714.94	$ 10,707.64	$ 11,029.31	$ 321.67

Regarding Algiers electric customers, the present typical bill is $131.05 and ENO's proposed rates would cause a typical bill of $136.29. This increase is due to the same FRP rate increase, plus an increase due to Rider BRAR of $4.47 (before the application of Franchise Tax), which we discuss later in this report. Our same recommended FRP rate for Algiers and Legacy Residential customers, combined with ENO's calculated BRAR rate increase results in a $136.14 typical bill, $0.15 less than ENO's proposal.

Table 11 presents the gas typical bill impact effect of the Advisor Adjustments and bill mitigation measures.

Table 11
Estimated Change to
Typical Gas Customer Monthly Bill

Rate Class	Typical Usage	Present	ENO Proposed	After Advisor Adjustments	Change from ENO Proposed
Residential	50 ccf	$ 61.59	$ 65.79	$ 65.54	($ 0.25)
Small General	500 ccf	$ 475.23	$ 503.72	$ 503.72	($ 1.75)
Large General	1,000 mcf	$ 7,937.22	$ 8,356.78	$ 8,356.78	($ 25.81)

OTHER MATTERS FOR COUNCIL CONSIDERATION

Below, we discuss certain matters that we identified for Council consideration, but which are not properly addressed in the FRP evaluation process. These are matters the Council may wish to address in future proceedings.

Mark to Market ADIT

As part of ENO Adjustment AJ03A.3, ENO credited ENO Account 283225 by $215,421 and ENO Account 283226 by $83,174 relative to FIN 48 tax positions (*i.e.*, tax positions that fail the FIN 48 uncertainty test) taken under IRC Sec. 475 (*i.e.* Mark to Market or "MTM"). These entries are to remove debit ADIT balances (*i.e.*, increases to rate base and ENO's cost of service) that in prior years were credit balances. ENO states, "From year-to-year, ENO does not know whether Accounts 283225 and 283226 [ENO Accounts for recording MTM ADIT] will have credit balances or debit balances because power/energy markets drive the MTM taxable income or tax deductions in each tax year. . . ENO requests that the Council establish a ratemaking rule regarding whether MTM ADIT associated with third-party PPAs should be included in rate base. This rule should apply regardless of whether the MTM ADIT increases or reduces rate base. A rule that MTM ADIT should be included in rate base only if the MTM ADIT reduces rate base would be arbitrary and capricious."[37]

MTM is an optional tax position that ENO is not obligated to undertake. However, should ENO opt for MTM treatment, all contracts must be given MTM treatment. Further, ENO's taxable income and taxable deductions are part of a consolidated return involving other companies. ENO

[37] FRP Evaluation Filing, *Summary Pleading,* XXIII and XXIV at 15

requests here that ratepayers compensate ENO for its optional MTM tax positions that this year would increase rates should their ADIT be allowed in rate base.

ENO should explain why ratepayers should compensate ENO for undertaking tax positions that provide ENO no tax benefits (*i.e.*, cause a debit ADIT balance). ENO should only undertake tax positions that provide useful capital (*i.e.*, a deferred tax liability recognized as a credit ADIT balance). To the extent ENO has undertaken MTM tax positions that harm ENO but benefit other companies that share ENO's consolidated tax return, ENO should explain why those companies should not bear the burden of these tax positions. In any case, the relief ENO requests is beyond the scope of an FRP Evaluation.

Meter Reading Expense

In ENO's 2022 FRP Evaluation Filing, ENO's adjusted Meter Reading Expense was a de minimis amount reasonably consistent with a completed AMI deployment. However, in the instant FRP Evaluation Filing, as well as the 2023 FRP Evaluation, ENO no longer proforms its per book meter reading expense to reflect any improvements from AMI. ENO's meter reading expense in its cost of service is \$0.3 million electric[38] and \$0.3 million gas.[39] This undermines the expected benefits of AMI investments. In *ENO's Application of Entergy New Orleans, Inc. for Approval to Deploy Advanced Metering Infrastructure, and Request for Cost Recovery and Related Relief*, Council Docket No. UD-16-04, ENO witness Dennis P. Dawsey represented "Because of the two-way data communication supported by AMI, all of the meter reading and nearly all meter services activity will be able to be performed remotely."[40] However, ENO now wants recovery of approximately \$0.6 million in meter reading expenses.

While outside the scope of a FRP evaluation, ENO's AMI investment, whose costs it continues to recover from ratepayers, has fallen substantially short of providing the ratepayer benefits represented to the Council by ENO's witnesses in Docket No. UD-16-04. We recommend that the Council direct ENO to prepare and file a report explaining, in detail, why its AMI deployment failed to generate its forecasted ratepayer savings.

Using AMI Capability to Develop Cost Allocation Factors

As discussed above, considering the lack of support ENO provided for a rigorous analysis of capacity-related allocation factors in the 2023 FRP evaluation and the instant FRP Evaluation Filing, the Advisors asked ENO why (assuming AMI plant and software system are functioning as intended) AMI could not be used in developing demand-related cost allocation factors, when one or more rate classes' contribution to the peak loads cannot be calculated from meter data.[41] ENO was unresponsive to that data request, referring instead to statistically designed samples to develop rate class demands, but which ENO would not, or could not, provide to the Advisors. ENO claimed: "It would not be practical to ensure the same high-quality data by using the full complement of available AMI metered data for all customers. Without the use of a rigorous VEE [*validation, editing, and estimating*] process, the use of the full AMI data would have the potential to introduce bias from data quality issues. The Advisors followed up with DR CNO 4-4, to which

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38 *See* FRP Evaluation Filing, *Compliance w Decoupling AJ01A A G Part 2*, RR4, OMCA902: 902 METER READING EXPENSE.

39 *See* EX1- O&M_G, EX1.1, line 26.

40 Council Docket No. UD-16-04, Direct Testimony of Dennis P. Dawsey at 11.

41 *See* DRs CNO 3-9 in the 2022 EFRP, CNO 5-3 in the 2024 EFRP, and ENO's response thereto.

ENO responded that upgraded systems and/or increases in resources may be required.[42] Apparently, the AMI systems investment, as proposed by ENO in Docket No. UD-16-04, did not include this AMI capability to support cost allocation, and perhaps other rate design analysis. With 99.6% of customers having AMI meters, it appears unreasonable that the AMI systems and considerable investment employed for monthly billing, revenue and customer support, cannot also be used to determine usage at monthly peak hours.

For ENO's related uses of AMI to estimate peak demands, see page 40 of the Energy Smart Third Party Evaluator's Report, included in the Energy Smart Implementation Plan for 2023-2025: "*With the full integration of AMI meters in the ENO service territory, ADM proposes to use AMI data to enhance the estimation of kWh savings and the estimation of kW reductions through the program. The AMI meter data will be collapsed to an average daily value by month instead of using monthly billing data. Using this high interval data, estimates, errors, irregular meter reads, and corrections in monthly billing data will be avoided and higher precision will be achieved. ADM will instead use the instantaneously collected AMI consumption data to summarize accurate estimates for each customer for each month. The Evaluator will use this AMI meter data to isolate ENO's peak demand window to model demand reductions because of behavioral changes through the program. Using observed interval data rather than a regional estimated loadshape allows more accurate estimation of demand reductions and informative conclusions to improve the program*."

More technical discussions between the Advisors and ENO are required to clarify this issue prior to the cost of service and decoupling analyses developed for ENO's next EFRP Evaluation.

Non-Typical Test Year

Past Advisor reports on annual FRP Evaluation filings have properly reflected adjustments to ENO's revenues to reflect non-typical test years. In the 2022 FRP evaluation, ENO estimated that its electric revenues were negatively impacted due to the loss of service to all of its service territory in the days following Hurricane Ida. To reflect this non-typical test year, we adjusted ENO's 2022 EFRP Present Revenues by $11,254,182 (which represented a decrease to ENO's FRP revenue requirement).

As part of our review of ENO's 2023 FRP Evaluation filing, we identified no significant non-typical conditions in 2022 affecting ENO's revenues. As such, per the text of Rider EFRP, which generally calls for the use of actual Test Year revenues, we did not recommend any adjustments to ENO's Present Revenues for that year related to non-typical conditions.

The same is true for ENO's 2024 FRP Evaluation filing: we identified no significant non-typical conditions in 2023 affecting ENO's revenues. As such, we do not recommend any adjustments to ENO's revenues in the FRP Evaluation based on a non-typical year.

[42] In the 2022 FRP Evaluation, ENO responded to DR CNO 4-4: "The use of the full AMI interval data stream without a validation process could have the potential to introduce bias from unknown data quality issues. AMI interval data can be incomplete and can contain errors at the individual customer level. ENO's current sampling process for calculating a rate classes' contribution to monthly peak load uses only AMI interval data that has been validated through the VEE process. Increasing the number of meters subject to the VEE process will potentially require upgraded systems and/or increases in resources."

Attachment A
Advisors' 2018 Rate Case Recommended Electric Revenue
Requirements by Rate Class

Line No.	Description	Total Company Adjusted	RES	Large Electric	Small Electric	Large Interruptible Service	Large Electric High Load Factor	High Voltage	Municipal Building	Master Metered Non Res	Lighting
[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]
1	Rate Base	777,383,427	425,338,913	48,750,285	114,482,471	4,645,876	164,739,772	5,995,785	3,942,686	75,013	9,412,623
2	ENO Required Rate of Return on Rate Base After taxes	6.91%									
3	ENO Required Rate of Return on Rate Base Including taxes	8.48%	1.60%	15.73%	18.32%	18.50%	15.79%	13.96%	21.31%	18.26%	20.16%
4	Return on Rate Base including income taxes	65,924,364	6,819,490	7,667,160	20,974,047	859,487	26,016,382	836,718	840,005	13,696	1,897,379
5	Operation & Maintenance Expense	404,211,278	190,661,260	29,152,919	60,943,027	6,183,538	104,114,314	7,715,058	2,118,224	42,493	3,280,454
6	Gains from Disp of Allowances	-	-	-	-	-	-	-	-	-	-
7	Regulatory Debits & Credits	4,538,904	2,420,822	295,209	678,021	30,096	1,003,174	38,751	23,427	452	48,952
8	Interest on Customer Deposits	895,555	489,996	56,161	131,885	5,352	189,782	6,907	4,542	86	10,843
9	Other Credit Fees	46,620	25,508	2,924	6,866	279	9,880	360	236	4	564
10	Depreciation & Amortization Expense	53,459,952	29,395,752	3,296,141	7,899,949	353,263	11,167,569	467,754	268,365	5,046	606,114
11	Amortization of Plant Acquisition Adjustment	1,189,690	540,672	91,545	185,581	15,824	319,821	24,277	6,675	133	5,161
12	Taxes Other than Income	20,940,293	11,518,901	1,279,645	3,123,711	136,916	4,343,957	181,630	105,934	1,997	247,602
13	SSCR (will be recovered w/ a Rider)	14,815,179	6,771,975	1,061,261	2,599,421	129,305	3,603,826	258,953	107,355	2,064	281,019
14	EECR (will be recovered w/ a Rider)	6,005,758	2,365,561	576,815	845,922	-	2,012,843	149,290	54,660	667	-
15	Less Credit to COS from Other Operating Revenue	(8,278,099)	(4,313,506)	(533,540)	(1,318,405)	(44,757)	(1,805,658)	(80,786)	(49,118)	(936)	(131,393)
16	**Total Cost of Service**	**563,749,493**	**246,696,430**	**42,946,239**	**96,070,024**	**7,669,302**	**150,975,890**	**9,598,911**	**3,480,305**	**65,703**	**6,246,695**
17	Less Present Revenue	596,853,414	250,098,239	46,736,829	96,599,501	11,061,296	166,588,860	13,381,097	3,773,720	79,482	8,534,390
18	**= Revenue Deficiency (Excess)**	**(33,103,921)**	**(3,401,809)**	**(3,790,590)**	**(529,477)**	**(3,391,994)**	**(15,612,970)**	**(3,782,186)**	**(293,415)**	**(13,779)**	**(2,287,695)**

Note: This Attachment was originally introduced as Exhibit VP-20 in the 2018 Rate Case.

Legend Consulting Group Limited

ENTERGY NEW ORLEANS, LLC
FORMULA RATE PLAN
Electric Utility Revenue Redetermination by Rate Class at Equal Rates of Return
ELECTRIC
Test Year Ending December 31, 2023

Line No.	Description	Total Company Adjusted	Residential	Small Electric	Municipal	Large Electric	High Load Factor	Master Metered	High Voltage	Large Interruptible	Lighting
[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]
1	Rate Base	1,276,624,874	718,489,482	189,156,673	12,908,711	76,459,293	250,103,787	1,738,626	10,235,299	7,186,320	10,346,682
2	ENO Required Rate of Return on Rate Base After taxes	7.28%									
3	ENO Required Rate of Return on Rate Base Including taxes	9.17%	3.75%	21.20%	10.94%	11.10%	14.33%	39.00%	14.38%	2.79%	18.40%
4	Return on Rate Base including income taxes	117,066,501	26,971,901	40,101,215	1,412,213	8,486,982	35,839,873	678,064	1,471,836	200,628	1,903,790
5	Operation & Maintenance Expense	483,934,346	248,433,652	68,943,465	2,298,857	31,200,115	115,026,791	659,166	8,946,558	6,706,373	1,719,370
6	Gains from Disp of Allowances	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
7	Regulatory Debits & Credits	(3,993,735)	(2,147,490)	(589,755)	(18,868)	(245,004)	(858,872)	(5,451)	(62,319)	(57,866)	(8,110)
8	Interest on Customer Deposits	2,327,938	1,310,173	344,929	23,539	139,424	456,067	3,170	18,664	13,104	18,867
9	Other Credit Fees	60,876	34,261	9,020	616	3,646	11,926	83	488	343	493
10	Depreciation & Amortization Expense	73,624,422	42,352,559	10,920,384	701,866	4,219,123	13,741,102	92,378	570,923	399,802	626,286
11	Amortization of Plant Acquisition Adjustment	1,190,642	605,790	180,272	3,845	79,225	282,977	1,750	23,002	13,781	-
12	Taxes Other than Income	20,658,940	11,796,442	3,078,078	184,446	1,179,509	3,934,255	26,611	178,871	127,247	153,482
13	Adjustment (Bad Debt, Reg. Exp. & Tax Difference)	(499,773)	12,682	(207,218)	(14,387)	(61,065)	(199,088)	314	(2,275)	(2,695)	(26,040)
14	SSCR (recovered w/ a Rider)	-									
15	SSCR II (recovered w/ a Rider)	-									
16	SSCO (recovered w/ a Rider)	-									
17	EECR (recovered w/ a Rider)	-									
18	Less Credit to COS from Other Operating Revenue	(75,906,483)	(33,307,143)	(11,556,962)	(359,150)	(5,314,263)	(21,022,379)	(118,051)	(1,824,608)	(1,801,971)	(601,956)
19	**Total Cost of Service**	**618,463,673**	**296,062,825**	**111,223,427**	**4,232,976**	**39,687,692**	**147,212,650**	**1,338,034**	**9,321,141**	**5,598,746**	**3,786,182**
20	Less Present Revenue [1]	611,429,800	294,808,828	106,073,829	3,962,561	39,543,954	145,852,857	588,565	9,246,704	6,285,520	5,066,982
21	**= Revenue Deficiency (Excess)**	**7,033,873**	**1,253,997**	**5,149,598**	**270,415**	**143,738**	**1,359,793**	**749,469**	**74,437**	**(686,775)**	**(1,280,799)**
22	Percent Increase on Total Revenues	1.2%	0.4%	4.9%	6.8%	0.4%	0.9%	127.3%	0.8%	-10.9%	-25.3%

Attachment B
Corrected Return on Rate Base
Calculation by Rate Class

Description	Line Item	Total Advisor Adjustments	Combined Total Company Adjusted	Residential	Small Electric Service	Municipal Buildings	Large Electric	Large Electric High Load Factor	Master Metered Non-Residential	High Voltage	Large Interruptible	Lighting Service
		Total Advisor Adjustments	Combined Total Company Adjusted	Residential	Small Electric Service	Municipal Buildings	Large Electric	Large Electric High Load Factor	Master Metered Non-Residential	High Voltage	Large Interruptible	Lighting Service
Rate Base	RBTOA: RATE BASE Total	(3,368,121)	1,273,256,753	720,251,385	181,056,388	7,982,013	76,488,772	255,354,740	854,450	10,096,298	8,084,051	13,088,656
ENO Required Rate Of Return On Rate Base Including Taxes	RORB IT	9.17%	9.17%	3.55%	21.54%	17.60%	11.62%	14.59%	18.00%	16.40%	2.80%	20.12%
Return On Rate Base Including Income Taxes		(308,857)	116,757,644	25,532,912	39,006,788	1,404,834	8,887,995	37,255,730	153,801	1,655,793	226,353	2,633,438
Operation & Maintenance Expense	OMTOA: OPERATION & MAINTENANCE EXPENSE Total	0	483,934,346	250,160,157	65,663,099	2,277,417	32,186,233	114,325,921	479,216	8,888,833	7,627,486	2,325,983
Gains From Disposition Of Allowances	GFDATOA: GAINS FROM DISP OF ALLOWANCES Total	0	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Regulatory Debits & Credits	RDCTOA: REGULATORY DEBITS AND CREDITS Total	0	(3,993,735)	(2,169,130)	(569,019)	(17,133)	(236,874)	(862,295)	(5,211)	(61,104)	(60,713)	(12,258)
Interest on Customer Deposits	ICDTOA: INTEREST ON CUSTOMER DEPOSITS Total	0	2,327,938	1,310,173	344,929	23,539	139,424	456,067	3,170	18,664	13,104	18,867
Other Credit Fees	OCFTOA: OTHER CREDIT FEES Total	18,968	79,844	45,166	11,355	501	4,795	16,013	54	633	507	821
Depreciation & Amortization Expense	DXTOA: DEPRECIATION AND AMORTIZATION EXPENSE Tot	(68,746)	73,555,676	42,452,280	10,546,648	520,104	4,213,410	14,022,869	57,465	564,758	437,996	740,147
Amortization of Plant Acquisition Adjustment	APAATOA: AMORTIZATION OF PLANT ACQUISITION ADJUS	0	1,190,642	616,803	173,144	5,029	79,638	274,672	958	22,756	15,220	2,422
Taxes Other than Income	TOTOA: TAXES OTHER THAN INCOME Total	0	20,658,940	11,818,245	2,985,723	133,280	1,171,356	4,035,658	20,304	176,305	136,362	181,706
Adjustment (Bad Debt, Reg. Exp. & Tax Difference)	Adjustment (Bad Debt, Reg. Exp. & Tax Difference)	3,622	(496,151)	12,590	(205,717)	(14,283)	(60,622)	(197,645)	312	(2,258)	(2,676)	(25,851)
		0	0	0	0	0	0	0	0	0	0	0
SSCR (recovered w/ a Rider)		0	0	0	0	0	0	0	0	0	0	0
SSCR II (recovered w/ a Rider)												
SSCO (recovered w/ a Rider)												
Less Credit To COS From Other Operating Revenue:		0	(75,906,483)	(33,307,143)	(11,556,962)	(359,150)	(5,314,263)	(21,022,379)	(118,051)	(1,824,608)	(1,801,971)	(601,956)
Total Cost Of Service		(355,012)	618,108,661	296,472,052	106,399,990	3,974,138	41,071,093	148,304,610	592,017	9,439,772	6,591,670	5,263,319
EAC Revenues	REVEAC: EAC Revenues		(0)	-	0	-	(0)	-	-	-	-	-
FAC Revenues	REVFAC: FAC Revenues	536,731	70,610,578	29,332,377	10,526,130	363,540	5,014,217	20,829,681	110,405	1,909,708	1,962,578	561,943
FRP Revenue	REVFRP: FRP Revenue	-	100,588,193	50,565,196	21,358,712	686,012	6,262,870	19,981,626	(89,928)	1,091,910	244,660	487,135
LCFC Revenue	REVLCF: LCFC Revenue	878,553	(6,543,655)	(3,203,392)	(1,150,260)	(42,107)	(407,516)	(1,515,288)	(8,950)	(89,313)	(63,373)	(63,457)
MISO Revenues	REVMIS: MISO Revenues	31,966	3,149,261	1,717,262	433,205	13,241	187,888	674,021	3,805	56,353	58,478	5,007
Purchase Power Revenues	REVPPC: Purchase Power Revenues	(538,873)	9,080,814	4,470,720	1,398,385	60,481	616,181	2,266,103	2,060	173,998	57,480	35,403
Sales Revenue	REVOTH: Sales Revenue	-	417,808,392	204,534,633	73,443,379	2,688,531	26,019,619	96,750,203	571,436	5,702,594	4,046,306	4,051,692
EECR Revenue	REVEEC: EECR Revenue	21,836	17,666,430	7,806,862	220,410	198,070	1,911,226	7,109,440	1,696	418,725	-	-
Present Revenue		930,214	612,360,014	295,223,659	106,229,962	3,967,768	39,604,486	146,095,786	590,525	9,263,975	6,306,129	5,077,723
FRP Revenue Change		**(1,285,226)**	**5,748,647**	**1,248,394**	**170,028**	**6,370**	**1,466,607**	**2,208,824**	**1,493**	**175,797**	**285,540**	**185,596**
			0.94%	0.42%	0.16%	0.16%	3.70%	1.51%	0.25%	1.90%	4.53%	3.66%

Attachment B

Advisor Adjustments to ENO's Proposed Ratemaking Treatment by Account		
ENO Account(s)	**Electric Adjustment DR/(CR)**	**Gas Adjustment DR/(CR)**
ADV01 – Rider Revenues		
RSRRFAC: 440-445 SALES–RETAIL - FAC	($536,731)	
RSRRMIS: 440-445 SALES–RETAIL - MISO	($31,966)	
RSRRPPC: 440-445 SALES–RETAIL - PURCHASED POWER CAPACITY	$538,873	
RSRREECR: 440-445 SALES–RETAIL - Energy Smart	$21,836	
Total Operating Revenues, Attachment B, Page 3, Line 3		($348,714)
ADV03 – LCFC		
RSRRLCF: 440-445 SALES–RETAIL - LCFC REVLCF: LCFC Revenue	($878,553)	
ADV04 – Storm Proforma Costs		
PLD361: 361 STRUCTURES & IMPROVEMENTS (DS-DD-TO) 1010AM: Electric Plant In Service	($14,776)	
PLD362: 362 STATION EQUIPMENT (DS-DD-TO) 1010AM: Electric Plant In Service	($432,116)	
PLD364: 364 POLES, TOWERS, & FIXTURES (D2-DD-TO) 1010AM: Electric Plant In Service	($389,634)	
PLD365: 365 OVERHEAD CONDUCTORS & DEVICES (D2-DD-TO) 1010AM: Electric Plant In Service	($648,295)	
PLD368: 368 LINE TRANSFORMERS (DX-DD-TO) 1010AM: Electric Plant In Service	($671,853)	
PLD3691: 369.1 OVERHEAD SERVICES (DV-CC-TO) 1010AM: Electric Plant In Service	($203,714)	
DXD361: 361 STRUCTURES & IMPROVEMENTS (DS-DD-TO) 4030AM: Depreciation Expense	($142)	
DXD362: 362 STATION EQUIPMENT (DS-DD-TO) 4030AM: Depreciation Expense	($4,579)	
DXD364: 364 POLES, TOWERS, & FIXTURES (D2-DD-TO) 4030AM: Depreciation Expense	($12,191)	
DXD365: 365 OVERHEAD CONDUCTORS & DEVICES (D2-DD-TO) 4030AM: Depreciation Expense	($20,521)	
DXD368: 368 LINE TRANSFORMERS (DX-DD-TO) 4030AM: Depreciation Expense	($20,027)	
DXD3691: 369.1 OVERHEAD SERVICES (DV-CC-TO) 4030AM: Depreciation Expense	($6,286)	
ADV05 – FIN 48 Interest		
OCFBL: BANK LOANS & FIN48 - INTEREST EXP	$18,968	$3,832
ADV06 – FIN 48 ADIT		
283225: Section 475 Adjustment-Fed	($734,437)	
283226: Section 475 Adjustment-St		($283,566)

Attachment D

Entergy New Orleans, LLC
Formula Rate Plan
Earned Rate of Return on Common Equity Formula
Electric
For the Test Year Ended December 31, 2023

Line No.	Description		Adjusted Amount As Filed by ENO	Advisor Adjusted Amount
	TOTAL COMPANY			
1	RATE BASE	Att B, P 2, L 23	1,276,624,874	1,273,256,753
2	BENCHMARK RATE OF RETURN ON RATE BASE	Att D, L 4, Col D	7.28%	7.28%
3	REQUIRED OPERATING INCOME	L 1 * L 2	92,938,291	92,693,092
4	NET UTILITY OPERATING INCOME	Att B, P 3, L 26	88,059,879	88,706,061
5	OPERATING INCOME DEFICIENCY/(EXCESS)	L 3 - L 4	4,878,411	3,987,030
6	REVENUE CONVERSION FACTOR (1)		1.4418	1.4418
7	REVENUE DEFICIENCY/(EXCESS)	L 5 * L 6	7,033,873	5,748,647
	PRESENT RATE REVENUES			
8	ULTIMATE CUSTOMERS	Att B, P 3, L 1	611,429,800	612,360,014
9	REVENUE REQUIREMENT	L 7 + L 8	618,463,673	618,108,661
10	PRESENT RATE BASE REVENUES	Att B, P 3, L 1	611,429,800	612,360,014
11	REVENUE DEFICIENCY/(EXCESS)	L 9 - L 10	7,033,873	5,748,647
12	REVENUE CONVERSION FACTOR (1)	L 6	1.4418	1.4418
13	OPERATING INCOME DEFICIENCY/(EXCESS)	L 11/L 12	4,878,411	3,987,030
14	RATE BASE	Att B, P 2, L 23	1,276,624,874	1,273,256,753
15	COMMON EQUITY DEFICIENCY/(EXCESS) (%)	L 13/L 14	0.38%	0.31%
16	WEIGHTED EVALUATION PERIOD COST RATE FOR	Att D, L 3, Col D	5.14%	5.14%
17	WEIGHTED EARNED COMMON EQUITY RATE (%)	L 16 - L 15	4.76%	4.83%
18	COMMON EQUITY RATIO (%)	Att D, L 3, Col B	55.00%	55.00%
19	EARNED RATE OF RETURN ON COMMON EQUITY (%)	L 17/L 18	8.66%	8.78%

Attachment D

Entergy New Orleans, LLC
Formula Rate Plan
Earned Rate of Return on Common Equity Formula
Gas
For the Test Year Ended December 31, 2023

Line No.	Description		Adjusted Amount as Filed by ENO	Advisor Adjusted Amount
	TOTAL COMPANY			
1	RATE BASE	Att B, P 2, L 18	214,490,009	214,490,009
2	BENCHMARK RATE OF RETURN ON RATE BASE	Att D, L 4, Col D	7.28%	7.28%
3	REQUIRED OPERATING INCOME	L 1 * L 2	15,614,873	15,614,873
4	NET UTILITY OPERATING INCOME	Att B, P 3, L 24	11,514,240	11,764,756
5	OPERATING INCOME DEFICIENCY/(EXCESS)	L 3 - L 4	4,100,633	3,850,117
6	REVENUE CONVERSION FACTOR (1)		1.3767	1.3767
7	REVENUE DEFICIENCY/(EXCESS)	L 5 * L 6	5,645,292	5,300,410
	PRESENT RATE REVENUES			
8	ULTIMATE CUSTOMERS	Att B, P 3, L 1	106,370,191	106,718,905
9	REVENUE REQUIREMENT	L 7 + L 8	112,015,482	112,019,314
10	PRESENT RATE REVENUES	Att B, P 3, L 1	106,370,191	106,718,905
11	REVENUE DEFICIENCY/(EXCESS)	L 9 - L 10	5,645,292	5,300,410
12	REVENUE CONVERSION FACTOR (1)	L6	1.3767	1.3767
13	OPERATING INCOME DEFICIENCY/(EXCESS)	L 11/L 12	4,100,633	3,850,117
14	RATE BASE	Att B, P 2, L 18	214,490,009	214,490,009
15	COMMON EQUITY DEFICIENCY/(EXCESS)	L 13/L 14	1.91%	1.80%
16	WEIGHTED EVALUATION PERIOD COST RATE FOR COMMON EQUITY (%)	Att D, L 3, Col D	5.14%	5.14%
17	WEIGHTED EARNED COMMON EQUITY RATE (%)	L 16 - L 15	3.23%	3.35%
18	COMMON EQUITY RATIO (%)	Att D, L 3, Col B	55.00%	55.00%
19	EARNED RATE OF RETURN ON COMMON EQUITY (%)	L 17/L 18	5.87%	6.09%