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July 15, 2025

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 2025 Electric and Gas Formula Rate Plan Filings Pursuant to Council Resolution Nos. R-19-457, R-20-344, R-23-423, and R-23-491, Riders EFRP and GFRP; Docket UD-18-07

Dear Clerk:

Attached please find the *Advisors to the Council of the City of New Orleans' Investigation and Review of Entergy New Orleans, LLC's 2025 Electric and Gas Formula Rate Plans Evaluation Filings* in the above-referenced matter. The Advisors submit this filing electronically and will submit the original and requisite copies as you direct. Thank you.

Best regards,

Jay Beatmann

JAB:dm
Attachment

cc: Official Service List for UD-18-07

INVESTIGATION AND REVIEW
OF
ENTERGY NEW ORLEANS, LLC'S 2025 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

PUBLIC REDACTED VERSION

JULY 15, 2025

Legend Consulting Group Limited

Introduction

On April 30, 2025, Entergy New Orleans, LLC ("ENO") submitted to the Council of the City of New Orleans ("Council") its *Entergy New Orleans, LLC's 2025 Electric and Gas Formula Rate Plan Filings* ("FRP Evaluation Filing" or "instant FRP Evaluation Filing") for the 12-month evaluation period ending December 31, 2024 ("2024 Test Year") to initiate new electric and gas rates effective with the first billing cycle of September 2025. In the FRP Evaluation Filing, ENO proposes a $7.5 million decrease and a $0.5 million increase to its electric and gas FRP revenues, respectively. While ENO proposes an electric FRP revenue decrease, the FRP Evaluation Filing also includes a $19.2 million roughly revenue-neutral credit realignment from the Purchased Power Cost Recovery Rider ("Rider PPCR") to the FRP (the "PPCR realignment"). As such, the FRP Evaluation Filing involves a net electric revenue increase of $11.7 million (-$7.5 million plus $19.2 million equals $11.7 million).

The FRP Evaluation Filing, inclusive of the PPCR realignment, results in a $5.01/month increase[1] to the typical residential electric bill and a $0.40/month increase[2] on the typical residential gas bill. However, as we discuss later in this report, the nature of the Rider PPCR's impact on the electric typical bill as measured in the FRP Evaluation Filing is not representative of its effect over a full year. Due to factors that are new to the instant FRP Evaluation, the customary "typical bill" calculation methodology[3] is not indicative of a typical bill in most months. While the FRP Evaluation Filing, which measures typical bills as of April 2025 indicates that Rider PPCR contributes a $6.03 increase to that month (with the FRP contributing -$1.02 for a net change of $5.01), across a full twelve months, Rider PPCR's rate increase due to the PPCR realignment contributes $4.33 to the typical bill. As such, over a twelve-month period, the FRP Evaluation Filing, inclusive of the PPCR realignment, results in a $3.32 increase to the typical bill ($5.01 minus $6.03 plus $4.33 equals $3.31, but these values are rounded to the penny, and we more precisely calculate $3.32). In our opinion, this is a more reasonable perspective of the FRP Evaluation Filing's impact on the residential typical electric bill. Later in this report, Table 4a presents the typical bill impacts of ENO's FRP Evaluation Filing, but with Rider PPCR's impact reflected over a twelve-month period.

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 FRP revenue increase by approximately $7.2 million and reduce the proposed gas FRP revenue increase by $0.5 million, all while still allowing ENO a reasonable opportunity to recover its costs and earn the Council-approved rate of return. We further recommend electric bill mitigation by employing unused credit amounts so that ENO's total electric revenues are unchanged.

The Advisors' recommended corrections result in a $1.98/month typical residential electric bill increase (based on the annual PPCR realignment analysis we discuss above). With the further

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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/month) impact of $5.01.

2 *See* FRP Evaluation Filing, *ENO GFRP Bill Comparison*, which presents a Residential Service typical bill (50 ccf/month) impact of $0.40.

3 ENO's rate action filings' typical bill calculations historically have calculated a snapshot of new rates compared to and applied to the month in which the filing was made. For the instant FRP Evaluation Filing, typical bills, both present and proposed, are as of April 2025.

mitigation credits that we recommend, the effect on typical residential electric is a $0.01/month decrease from present. Small Electric typical bills, with Advisor adjustments, are $16/month less than present. Large Electric typical bills, with Advisor adjustments, are $177/month less than present. The Advisors' recommendations eliminate ENO's proposed $0.40/month increase on the typical residential gas bill, *i.e.*, typical bills would be unchanged.

BACKGROUND

Prior FRP Evaluation Filings

ENO prepared its 2020 FRP Evaluation Filing (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, 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[4] (*e.g.*, a 51% hypothetical equity ratio), beginning in November 2021.

ENO's 2021 FRP Evaluation Filing proposed an increase in electric revenue of $40 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' 2021 FRP 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 gas and electric FRP rates that reflected the revenues by rate class that the Advisors had recommended while allowing ENO the reasonable opportunity to earn its Council-allowed Return on Equity ("ROE") of 9.35%.[5]

ENO's 2022 FRP Evaluation 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 gas and electric FRP rates that reflected the revenues by rate class that the Advisors had recommended, and the mitigation credits were applied to Rider PPCR.

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

5 *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.

ENO's 2023 FRP Evaluation 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.

ENO's 2024 FRP Evaluation Filing proposed a $7.0 million increase to its electric revenues and a $5.6 million increase to its gas revenues. The Advisors recommended a reduction to ENO's proposed electric revenue increase of $1.3 million and a reduction to the proposed gas revenue increase of $0.3 million. Following discussions between the Parties, ENO implemented a $5.8 million increase to its electric revenues (a $1.2 million decrease from its proposal) and a $5.4 million increase to its gas revenues (a $0.2 million decrease from its proposal).

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 $7.2 million for the electric utility and $0.5 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.

Table 1 **Summary of Advisor Recommended Adjustments** **($ in Millions)**		
	Electric	Gas
ENO Proposed FRP Revenue Increase (Decrease)	**($7.5)**	**$0.5**
Advisor Adjustments to Evaluation Report	($7.2)[1]	($1.2)
Advisor Recommended Rate Mitigation Credits	($4.4)	-
FRP Revenue Increase (Decrease) After Advisor Adjustments	**($19.2)**[2]	**$0.0**[3]

Notes:

1. ENO's proposed electric FRP revenue decrease of $7.5 million is $13.8 million in bandwidth revenue adjustments, net of $6.2 million in outside the bandwidth revenue increases.[6]
2. The $19.2 million FRP revenue decrease presented in Table 1 above is offset by a roughly equal Rider PPCR revenue increase, which we discuss in a section later in this report. As such, after Advisor adjustments and recommended mitigation credits, ENO's electric revenues remain unchanged.
3. The gas revenue change after Advisor adjustments is zero because ENO's Advisor-adjusted an Earned Return on Common Equity ("EROE") is within the bandwidth. As such, no changes to ENO's gas revenues are provided for by the terms of the FRP.

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 gas FRP revenue increase, and ENO has requested FRP rate adjustments to prospectively (*i.e.*, commencing with the first billing cycle of September 2025) reset electric rates consistent with the FRPs' midpoint ROE of 9.35%. As the gas EROE falls within the FRP bandwidth, no rate reset is appropriate (an Advisor adjustment removes a $0.5 million outside the bandwidth adjustment). As discussed later in this report, decoupling is a required element of the electric FRP Evaluation filing, and the decoupling mechanism is utilized in determining customer class revenue requirement allocations in each test year FRP Evaluation filing.

Table 2 presents the as-filed FRP Evaluation Filing electric revenue change by rate class.[7]

6 *See* ENO's response to DR CNO 1-53 ($1.1 million due to Resilience & Storm Hardening Cost Recovery Rider ("Rider RSHCR"), $1.0 million related to the settlement of the reliability investigation, and $4.1 million to recover ENO's proposed reduction in Late Payment Charge rates).

7 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	$181,702,781	($1,664,057)	-0.9%
Small Electric Service	72,876,039	(2,517,537)	-3.5%
Municipal Buildings	3,129,921	3,536,059	113.0%
Large Electric	25,164,822	(2,298,589)	-9.1%
Large Electric High Load Factor	94,827,767	(3,000,840)	-3.2%
Master Metered Non-Residential	504,152	50,351	10.0%
High Voltage	5,695,339	32,587	0.6%
Large Interruptible	3,795,467	(307,764)	-8.1%
Large Municipal	1,441,998	(108,259)	-7.5%
Lighting Service	3,979,682	(1,248,596)	-31.4%
Total	$393,117,968	($7,526,646)	-1.9%

As we discuss later in this report, the primary cause of the $7.5 million electric FRP revenue reduction in Table 2 above is the PPCR realignment (roughly $19.2 million).[8] This realignment has no significant effect on ENO's annual revenues (*i.e.*, the PPCR realignment is roughly revenue neutral). Absent this realignment, proposed electric revenues would have increased by $11.7 million. Table 2a below summarizes this more comprehensive view of electric revenue changes in ENO's FRP Evaluation Filing.

8 *See* ENO's response to DR CNO 5-1, timely filed on July 9, 2025, after the completion of our analyses in support of this report. ENO's response to this DR indicates that, "it inadvertently miscalculated the credits to be returned in the PPCR rider from January through August 2025." ENO's updated Rider PPCR credits have a modest effect on the PPCR realignment (causing it to be more nearly revenue neutral).

Table 2a ENO Overall Revenue Filing Change in Electric FRP Revenues			
Rate Class	Applicable Base Revenue	Proposed Change in FRP and Rider PPCR Revenue	Proposed Change in FRP and Rider PPCR Revenue as Percent of Base Revenue
Residential	$181,702,781	$7,108,689	3.9%
Small Electric Service	72,876,039	493,640	0.7%
Municipal Buildings	3,129,921	3,644,370	116.4%
Large Electric	25,164,822	(813,203)	-3.2%
Large Electric High Load Factor	94,827,767	2,188,472	2.3%
Master Metered Non-Residential	504,152	52,519	10.4%
High Voltage	5,695,339	426,500	7.5%
Large Interruptible	3,795,467	(174,842)	-4.6%
Large Municipal	1,441,998	(108,259)	-7.5%
Lighting Service	3,979,682	(1,164,854)	-29.3%
Total	$393,117,968	$11,653,031	3.0%

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	$23,611,307	$351,497	1.5%
Small General	5,351,022	76,660	1.5%
Large General	5,378,495	80,069	1.5%
Small Municipal	50,442	751	1.5%
Large Municipal	1,702,783	25,349	1.5%
Total	$36,094,050	$537,325	1.5%

The proposed increase to gas FRP revenues is due to ENO's proposed change to Late Payment Charge ("LPC") rates. ENO is seeking recovery through an outside the bandwidth FRP rate increase of revenues it expects to lose due to its proposed reduction in LPC charge rates. ENO is proposing no bandwidth adjustment to gas FRP rates (*i.e.*, ENO's gas EROE is within the bandwidth).

Earned Rate of Return

ENO's FRP Evaluation Filing reports EROE.[9] ENO's stated electric EROE is 10.98%, and ENO's stated gas EROE is 8.96%.[10] Per the FRP riders' bandwidth of +/- 50 bp,[11] 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%. Similarly, if ENO's electric or gas EROE rises above 9.85%, a downward adjustment to ENO's FRP rate is required.

After applying the Advisor Adjustments to correct for identified errors in the FRP Evaluation, but not the Advisors' recommended mitigation credits, ENO's electric EROE is 11.36%, and ENO's gas EROE is 9.55%.

ENO's electric Advisor-adjusted EROE value remains above 9.85%, and therefore we have calculated a downward electric FRP rate adjustment to allow ENO the reasonable opportunity to earn an EROE of 9.35%. ENO's gas Advisor-adjusted EROE is within the bandwidth (as was the FRP Evaluation Filing's gas EROE), thus no FRP rate adjustment is appropriate.

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

New Electric Rate Class

The instant FRP Evaluation Filing contains revenues and cost allocations to the Large Municipal electric rate class, consisting of one customer, the [redacted]. The first bill to this rate class was issued in December 2024.[12] ENO started billing this customer the customer charge and volumetric charge associated with minimal energy usage.[13] 2024 per book revenues for this rate class totaled $0.7 million,[14] but a complete 2024 per book revenue amount is not available for the instant FRP Evaluation. Instead, ENO calculated a proforma base revenue value of $1.4 million for this rate class, which is based on hypothetical 5,000 kW load and 9,000 kWh energy billing determinants.[15] In our opinion, while it is generally required by the FRP's language to base revenues on test period actual revenues, ENO's proforma adjustment is appropriate. It is necessary to set FRP rates for this new rate class, and the mechanics of the decoupling provision in the FRP require allocations of costs and revenues among all rate classes. ENO has made conservative assumptions as to the new rate class's billing determinants, but it is unknown what this customer's actual electric usage will be for the rate effective period (*i.e.*, September 2025-August 2026). As such, we did not identify any errors in ENO's proforma revenue value for the Large Municipal rate class in the instant FRP Evaluation Filing.

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9 *See* FRP Evaluation Filing Attachment B at 1.

10 *Id.*

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

12 *See* ENO's response to DR CNO 2-4.

13 *Id.*

14 *See* ENO's response to DR CNO 1-15, file *TC-UD1807-07ADV001-N015*.

15 Id.

Typical Bill Impact

ENO's estimate of electric and gas typical bill impacts from its FRP Evaluation Filing are presented in Tables 4 and 5.

Table 4
ENO FRP Evaluation Filing Estimated Change to Typical Electric Customer Monthly Bill
(Legacy, Decoupling Compliance, April Measurement)

Rate Class	Typical Energy (kWh)	Typical Demand (kW)	Present	Proposed	Change
Residential[1]	1,000	-	$155.94	$160.96	$5.01
Small Electric	9,125	50	$1,563	$1,576	$13.07
Large Electric	91,250	250	$12,055	$11,823	($232)

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/month).

Of note, Residential and Small Electric typical bills are proposed by ENO to increase, despite a reduction in FRP revenues because the PPCR realignment is roughly revenue neutral (*i.e.*, the credit to Rider FRP is offset by a debit to Rider PPCR). Further, as we discuss in the introduction to this report and in a later section, the above electric typical bills reflect an April 2025 measurement date. Specific to the PPCR realignment and resulting PPCR rate, this single measurement point is not as helpful as a full year measurement. Table 4a below presents the typical bill impact of ENO's proposed rates, but with a Rider PPCR rate reflective of a full year's effect.

Table 4a
ENO FRP Evaluation Filing Estimated Change to Typical Electric Customer Monthly Bill
(Legacy, Decoupling Compliance,
Annual PPCR Realignment Measurement)

Rate Class	Typical Energy (kWh)	Typical Demand (kW)	Present	Proposed[2]	Change
Residential[1]	1,000	-	$155.94	$159.26	$3.32
Small Electric	9,125	50	$1,563	$1,569	$6
Large Electric	91,250	250	$12,055	$11,783	($272)

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/month).
2. Proposed typical bills reflect ENO's proposed rates, but with Rider PPCR's proposed rate to reflect a twelve-month realignment of credits as opposed to an April 2025 measurement.

As presented in Table 6 below, ENO's proposed change in electric FRP revenues absent the effect of Rider PPCR credits is a $11.7 million increase. Regarding the Large Electric rate class, due to changes in cost allocations in ENO's decoupling methods, the decrease in FRP rates ($616/month impact on typical bill) exceeds the increase in Rider PPCR rates ($394/month impact on typical bill), which is the substantial cause of ENO's proposed decrease in this rate class's typical bill.[16]

Table 5
ENO Proposed Estimated Change to Typical Gas Customer Monthly Bill

Rate Class	Typical Usage	Present	Proposed	Change
Residential	50 ccf	$78.11	$78.51	$0.40
Small General	500 ccf	$627.26	$629.99	$2.73
Large General	1,000 mcf	$10,833	$10,873	$40.14

ENO's proposed $0.5 million FRP revenue increase related to LPC rates is the cause of the proposed change to gas typical bills. Apart from this proposed outside the bandwidth FRP rate adjustment, typical gas bills would be unchanged.

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 five sets of discovery to ENO consisting of 79 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 2025-August 2026);
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

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16 These values do not sum to Large Electric's overall typical bill change due to the elimination of Rider BRAR's surcharge on Large Electric.

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 Change in FRP Revenue (Bandwidth Adjustment)	**($13.8)**	**$0.0**	**($13.8)**
Outside the Bandwidth Revenues			
Rider RSHCR Revenue Requirement	*$1.1*	-	*$1.1*
Reliability Investigation Settlement	*$1.0*	-	*$1.0*
LPC Rate Reduction	*$4.1*	*$0.5*	*$4.6*
Total Outside the Bandwidth Revenue	**$6.2**	**$0.5**	**$6.7**
ENO Proposed Incremental FRP Revenues	**($7.5)**[1]	**$0.5**	**($7.0)**
Less PPCR Realignment	**$19.2**[2]	**-**	**$19.2**
Net ENO Proposed Incremental FRP Revenues	**$11.7**	**$0.5**	**$12.3**
Advisor Adjustments			
ADV01 – Rider Revenues	($0.3)	$0.2[4]	($0.1)
ADV03 – LCFC[17]	($0.3)	-	($0.3)
ADV04 – Storm Proforma	($0.6)	-	($0.6)
ADV06 – FIN 48 Interest	$0.0	-	$0.0
ADV07 – Disallow LPC Rate Change[3]	($4.1)	($0.5)	($4.6)
ADV08 – Return UPITA Over 12 Months	($1.1)	($0.8)[4]	($1.9)
ADV09– Return Income Tax Overcollection	($0.8)	(0.1)[4]	($0.9)
Total – Advisor Adjustments	**($7.2)**	**($1.2)**	**($8.4)**
Total Advisor Adjusted Net FRP Revenue Change	**$4.4**	**$0.0**[4]	**$4.4**
Recommended Mitigation Credits	($4.4)	**-**	($4.4)
Total Advisor Adjusted Net FRP Revenue Change (Including Mitigation)	**$0.0**	**$0.0**[4]	**$0.0**

Notes:

1. ($7.5 million) represents a $13.8 million bandwidth revenue adjustment plus $6.2 million in outside the bandwidth revenues.
2. The PPCR realignment is roughly revenue neutral. As such, it is useful to consider FRP revenues net of this realignment.
3. ENO's proposed LPC-related electric and gas FRP adjustments, as well as our adjustment to disallow these proposals, are outside the bandwidth.
4. Because ENO's gas EROE is within the bandwidth, these adjustments have no effect on gas rates.

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[18] 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 Council Resolution No. R-19-457, the Council approved the FRP mechanisms and directed that the total utility cost of service include total ENO revenues and expenses[19] 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,"[20] (Emphasis added.) The Advisors' investigation, review and examination of ENO's 2021, 2022, 2023 and 2024 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.[21] Based on these Council directives, the electric FRP 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.[22] 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.

17 Lost Contribution to Fixed Cost.

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

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

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

21 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, CNO 1-14, 4-5, 4-6, 4-7, and 5-2 in the 2024 FRP, and CNO 1-6, 1-15, 1-16, 1-52, 2-4, 2-5, 3-3, 3-7, 3-8, and 3-9 in the 2025 FRP.

22 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. at 13 & 24.

"The auditor should begin by looking at an analysis of the test year revenues…" NARUC Rate Case and Audit Manual 2003. at 31.

"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. at 3-4.

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[23] 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 $347,640 fuel (FAC), ($117,167) EECR, $125 EAC, ($38,666) MISO, and ($556,323) PPCR for a total decrease to ENO's present revenue (*i.e.*, increase to ENO's revenue deficiency) of $364,391.

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 $303,970.

LCFC (ADV03)

In Council Resolution No. 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.[24] In the LCFC discussion in the 2018 general rate case, ENO's proposal advocated LCFC recovery based on actual results.[25] 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 data and not the kWh savings goals included in the approved Energy Smart Implementation Plan."[26]

ENO did utilize actual data in calculating its LCFC adjustment in the instant FRP Evaluation Filing, using the three-year average of the percent of Energy Smart kWh savings goal that was achieved (program years 2021 through 2023[27]), which is the consistent with the agreed-to ratemaking treatment for LCFC. As with last year's FRP evaluation, we are able to add Energy Smart Program Year 2024 kWh savings data to which to this year's calculation with ENO's Program Year 2024 kWh savings data, filed on June 30, 2025.[28]

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23 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 1-15, 1-16 and 3-9.

24 Council Resolution No. R-20-51, at 27-28.

25 See Council Resolution No. R-19-457, at 156.

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

27 *See* Evaluation Report, AJ05D.2, FN 2.

28 See Entergy New Orleans, LLC's Lost Contribution to Fixed Costs and Utility Performance Incentive Filing for Energy Smart Program Year 14 Resolutions R-15-140 and R-20-51 CNO Dockets UD-08-02 (IRP-Energy Smart-RFP), UD-17-03 (2018 IRP) and UD-23-01 (2024 Triennial IRP), June 30, 2025.

Accordingly, the Advisors have adjusted ENO's LCFC proforma amount to reflect an average kWh savings as percent of goal for the 2022-2024 Program Years. This adjustment improves the predictive quality of that Evaluation's LCFC adjustment.

Regardless of the LCFC adjustment reflected in ENO's FRP rate, there will be a true-up to actual LCFC costs through Rider EECR.[29] The LCFC true up for ENO's 2025 pro-forma estimate will be included in the EECR Filing mid-year 2026, for recovery in EECR rates effective for calendar year 2027.

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.*, 2025 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.[30]

ENO has requested a $[redacted][31] proforma addition to distribution plant in service related to storm restoration capital costs that may be incurred in 2025 with respect to minor weather events. As with ENO's prior FRP Evaluation Filings, 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.

As such, consistent with our recommendations in our 2024 report, ENO erred in proposing the proforma adjustment to add $[redacted] 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 reflects ($[redacted]) (a credit or negative expense)[32] in calculated interest on tax positions that in ENO's opinion do not meet the "more-likely-than-not recognition threshold"[33] of being allowed by the IRS upon audit (*i.e.*, FIN 48 tax positions).[34] The 2024 FRP Evaluation likewise proposed a negative FIN 48 interest expense adjustment. In other prior FRP Evaluations, ENO has requested a debit or positive FIN 48 interest expense. Regardless of whether the interest adjustment is a debit or a credit, ENO has erred in its proposal, and it is

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29 Council Resolution No. R-23-491, at 5.

30 Rider Schedule EFRP-7, FN 1 at 30.3.

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

32 *See* ENO's HSPM response to DR CNO 1-30.

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

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

appropriate to correct ENO's error. We have corrected ENO's error regarding FIN 48 interest by reversing (negative) expenses through Advisor Adjustment ADV05.

LPC Rate Adjustments (ADV07)

In the FRP Evaluation Filing, ENO proposes that the Council change the LPC rates that the Council last evaluated and fixed as part of the 2018 Rate Case. Presently, ENO is authorized to charge an electric LPC of 5% for Residential and Small Electric and 2% for other rate classes.[35] Likewise, ENO is authorized to charge a gas LPC of 5% for Residential and Small General customers and 2% for other customers. ENO proposes to reduce the LPC rate to 1.5% for all electric and gas customers. ENO states that it selected a 1.5% LPC rate because that is the fee approved by the Louisiana Public Service Commission, and further ENO cites other utilities whose LPC rates are at the 1.5% level.[36] ENO proposes a revenue neutral outside the bandwidth FRP rate adjustment of $4,121,106 and $537,325 for electric and gas respectively to reflect revenues ENO expects to lose due to the new lower LPC rates.

ENO argues that the instant FRP Evaluations are the earliest available proceeding to consider new LPC rates.[37] But nothing in the FRP tariffs provides for an adjustment to miscellaneous fees such as the LPC. The purpose and scope of the FRP Evaluations is to reset base rates to allow ENO the reasonable opportunity to earn its Benchmark Rate of Return, as determined by the bandwidth calculation.[38] The FRP tariffs do not discuss or authorize other rate adjustments. As such, ENO's proposal is inappropriate as outside the scope of instant FRP Evaluation. Further, the instant FRP Evaluation may not provide for the input from all interested parties that may be required for the Council to develop a complete record upon which it may rely when setting new LPC rates. We do not recommend that the Council change its current LPC rates as part of the instant FRP Evaluation. The Advisors have removed ENO's LPC-related FRP revenues from their recommended FRP rates.

Should the Council decide to change ENO's authorized LPC rates, we note an error in ENO's FRP Evaluation Filing, specifically ENO's outside the bandwidth treatment of the FRP rate adjustment to realign LPC-related revenues to FRP rates. Any LPC-related FRP adjustment should be inside the bandwidth. ENO justifies its outside the bandwidth treatment as not affecting its bandwidth formula calculation.[39] However, LPC-related revenues have been treated as inside the bandwidth amounts in each of ENO's FRP Evaluation Filings since the 2018 Rate Case. LPC-related revenues are appropriately an inside the bandwidth amount, and ENO has erred in attempting to move them

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35 *See* FRP Evaluation Filing, file *Att F_Line 16 Late Fee_E_WP*.

36 *See* ENO's response to DR CNO 2-3.

37 *Id* at subpart d.

38 Revenues related to Rider RSHCR are recovered through an adjustment to FRP rates.

39 *See* ENO's response to DR CNO 2-3.e.

outside the bandwidth. Should the Council decide to change ENO's authorized LPC rates, we recommend that they be given inside the bandwidth treatment.

Consistent with the Advisors' not recommending that the Council change LPC rates in the instant FRP Evaluation, we have removed $4,121,106 and $537,325 from ENO's proposed outside the bandwidth revenues for electric and gas, respectively.

Return UPITA (ADV08)

Due to a 2025 reduction to the Louisiana state income tax rate, ENO has recorded a deferred tax liability related to Unprotected Excess Deferred Income Tax ("UPITA") in the amounts of $1.8 million and $1.3 million for electric and gas respective. Through ENO adjustment AJ03C, ENO proposes to amortize these liabilities over three years. As they are unprotected, these funds are returnable according to the Council's direction. We believe that these amounts are not so substantial that a faster return constitutes an unreasonable burden on ENO. As such, and since the Council has not authorized a deferral of the return of these funds, a return over a single year is appropriate.

Consistent with our view on the returnability of these funds to ratepayers, we have adjusted ENO's FRP Evaluation Filing to remove the deferred liability and credit revenue requirement by the liabilities' full amounts.

Return Income Tax Overcollection (ADV09)

Due to the same 2025 reduction to the Louisiana state income tax rate that we discuss relative to Adjustment ADV08, by August 30, 2025, ENO's present rates will have allowed it to over recover state current income tax expense by $1.3 million and $0.2 million for electric and gas, respectively. Through ENO adjustment AJ03D, ENO proposes to capitalize and amortize these overcollections over three years. We believe that these overcollection amounts are not so substantial that a faster return constitutes an unreasonable burden on ENO. As such, and since the Council has not authorized a deferral of the return of these funds, a return over a single year is appropriate.

Consistent with our view on the returnability of these funds to ratepayers, we have adjusted ENO's FRP Evaluation Filing to remove the proposed regulatory liability and credit revenue requirement by the overcollections' full amounts.

Match Allocation Factors for Regulatory Liabilities

Relative to the PPCR realignment, which we discuss later in this report, ENO has recorded a regulatory liability in ENO Account 254RBO, whose balance ENO allocates according to production demand ("PG-DD-TO"), while the amortization of the regulatory asset is allocated according to ENO's total plant ("PLTOA"). While not substantial, we synchronized these accounts to both use the total plant allocator. This adjustment has no effect on ENO's total EROE or revenue requirement but has a small effect on revenues among the electric rate classes.

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 Council Resolution No. 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-7 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 class revenues set in Docket UD-18-07. Consistence 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 FRP Evaluation Filing raised some questions when compared to the comparable allocation factors developed in the recent 2018 Rate Case and the several FRP Evaluation 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 FRP evaluation. Yet, based on the data in the past FRP Evaluation Filings, the annual estimated Residential customer class ratio of average demand to 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 load factors have ranged from 62.6% to 50.4%, with 58.5% estimated for the instant FRP Evaluation Filing. This range of estimated residential load factors, when compared to a relatively stable residential average monthly usage, would infer that FRP 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 require estimation, and small variations in the estimates result in significant changes to the allocated residential cost of service. That estimation had previously required the use of load research data, with sampled results of a small group applied statistically to the entire residential customer class. Although there has been no change to the methodology ENO uses to produce the underlying demand data for the FRP Evaluation Filings, an ENO contractor has developed demand peak data for recent test periods, including the FRP Evaluation Filing. The services of the contractor have enabled the Company to incorporate large amounts of data that are now available from the implementation of AMI. For example, ENO has increased its sampling methods from 300 customer samples to over 1,500 customer samples, which are referred to as "super samples." ENO provided workpapers in response to discovery[40] that support the current approach and processes implemented by ENO to develop coincident peak demands, allowing for rigorous validation, editing and estimation ("VEE").

However, it is still reasonable to recognize variations in data occurring over a period of recent years, to provide more consistency in allocated costs in annual FRP evaluations. As an example, ENO's peak demand for each of the twelve months in the 2024 test year occurred during daylight or non-dark hours, when lighting did not contribute to the coincident peak. Based on that one test period set of results, the lighting class of service would receive no portion of production and transmission fixed costs and related expenses. Yet two years previous, the test period results

[40] See response to CNO-ENO 5-3, 2024 FRP, Docket No. UD-18-07.

provided an allocation of some portion of production and transmission fixed costs of service. The Company did not develop any analysis for lighting and did not consider any adjustment for the lighting class that would be different from the actual current test period demand allocation factor data.

The Advisors have selected averaging the demand allocation factors developed from the most recent three test periods to recognize both the recent approach and processes implemented by ENO to develop peak-related demand allocation factors, as well as to strive towards consistency in cost allocation factors from year to year. The kW peak demands from each of the recent three FRP test periods were combined for each of the customer classes resulting in weighted capacity-related fixed cost allocation factors which were used in the Advisors' decoupling analysis.[41]

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%.[42] With the Advisors' proposed change in total FRP revenue, (see Table 8) 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 2024 Test Year. 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.

Other FRP Ratemaking Matters Not Involving an Adjustment

Rider BRAR

Prior to the 2018 Rate Case, electric customers in Algiers had different rates than in the rest of New Orleans ("Legacy ENO"). In particular, Algiers residential rates were substantially less than Legacy ENO residential rates. As part of the 2018 Rate case, the Council sought to mitigate any rate shock Algiers residential customers might experience from an immediate harmonization of residential rates between Algiers and Legacy ENO. To accomplish this mitigation, Base Rate Adjustment Rider ("BRAR") credited Algiers residential rates and paid for this credit by a surcharge to large and industrial customer classes. Initially following the 2018 Rate Case, Rider BRAR credited Algiers residential customers 10.588% of their Legacy ENO bill amount.[43] This had a summer Algiers typical bill impact of ($9.27).[44]

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41 "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, at 6.

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

43 See ENO's December 9, 2019 Compliance Filing Pursuant to Council Resolution No. R-19-457 CNO Docket UD-18-07 at 40.2.

44 *Id.* Statement AA5_E at 17.

The present BRAR rate credits Algiers residential customers 0.783% of their base rate at a cost to large and industrial customers of approximately $0.2 million per year. This present credit results in a $0.68/month residential Algiers typical bill reduction compared to a Legacy ENO typical bill. This 0.783% rate compares to a 5.929% rate set as part of the 2023 FRP Evaluation. ENO proposes setting the BRAR rate and related charges to large and industrial customers at zero, effectively terminating BRAR. This proposed change to BRAR rates is provided for by Council Resolution No. R-19-457,[45] 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' magnitude. Whenever residential rates increase by less than 4% as part of a FRP Evaluation, BRAR rates may decrease in magnitude to cause an overall 4% increase in Algiers residential rates. In the Instant FRP Evaluation, residential FRP revenue is actually decreasing, which provides for the elimination of the remaining approximately $0.2 million BRAR credit.

Going forward, all ENO electric rates will be equal throughout ENO's service territory. However, the electric franchise fee in Algiers remains 2%, while the rest of New Orleans's electric franchise fee is 5% (the gas franchise fee is 5% for all of New Orleans).

PPCR Realignment

Per Council Resolution Nos. R-24-194 and R-24-195, the PPCR realignment in the FRP Evaluation Filing has realigned ratepayer credits presently reflected in Rider PPCR into FRP rates. These credits relate to a $44 million regulatory liability related to a global settlement between the Council and System Energy Resources Inc. ("SERI") and a $138 million regulatory liability related to settlement of the sharing of certain tax benefits arising from the audit of tax returns filed on behalf of ENO for the years 2016-2018. The amount of these PPCR credits for the April 2025 billing month (the month for which ENO calculated typical bill impacts for the FRP Evaluation filing) totaled $1,606,779, which roughly equates to a $19.2 million annual credit realignment (the PPCR credits that would have been applied across all of 2025). The realignment of PPCR credits to the FRP is roughly revenue neutral to ENO.[46]

Relative Rate Class Impact

The PPCR credit realignment has multiple factors affecting the various rate classes differently.

a. Rider PPCR allocates the credits according to a production allocator that was set as part of the 2018 Rate Case, while the equivalent inputs to the FRP rate calculation use allocators that have been recalculated with each FRP evaluation per the FRP tariff's decoupling provision.

[45] *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.

[46] The realignment, by measuring the regulatory liabilities as of December 31, 2025, rather than monthly in Rider PPCR, affords ENO a small benefit of negative regulatory lag for the months January through August (partly offset by negative regulatory lead in September through November), which we have not considered in this discussion in the interest of clarity.

b. Rider PPCR provides a revenue credit on the regulatory liabilities' balance at ENO's WACC for all rate classes, while the FRP provides rates that vary substantially by rate class (while maintaining a total company WACC of 9.10%).

As such, rate classes are affected differently in terms of changes to their allocated cost responsibilities. For example, Residential's net realignment revenue increases by approximately $2.7 million, while Municipal Buildings' revenue decreases by $3.8 million. For this reason, among others, as we discuss later in this report, we recommend that the Council mitigate residential bills in the instant FRP Evaluation.

Typical Bill Impact of Rider PPCR Credits

For PPCR rate calculations, April is the month having the lowest base revenue,[47] however, the typical bill calculation always reflects a 1,000 kWh/month residential usage. This causes the typical bill effect of a change in Rider PPCR's rate, in this case the effect of a $19.2 million revenue increase, to appear larger in April than in other months. As such, the month of the measurement of a change to PPCR credits has a significant effect on typical bill calculations.

The Residential typical bill (1,000 kWh/month Legacy, summer/winter average) effect of removing this PPCR credits from the April 2025 PPCR calculation is a $6.03 increase. Had the same credits been removed from ENO's total 2025 PPCR rate calculation, the impact on the Residential typical bill would be $4.33/month As we discuss in the introduction to this report, this whole-year perspective is more useful for the understanding of the PPCR realignment.

The application of the account balances relevant to the PPCR realignment[48] to the FRP's rates results in an approximate $3.07/month typical bill decrease across all twelve months (Legacy, summer/winter average). As such, the PPCR effect on typical bills of the realignment is greater or lesser than this amount depending on the month: Over a full year's billings, this net residential typical bill impact is $1.26/month ($4.33 minus $3.07).

In summary, while the typical bill impact calculation that the Council has relied on for many years has been useful, in the particular case of this year's PPCR realignment, this tool distorts what ratepayers will actually experience over a full year. As such, the rate mitigation that the Advisors offer for Council consideration is intended to keep ENO's revenues unchanged from last year's FRP Evaluation and also prevent a residential typical bill impact when measured across a twelve-month period. Over a full year, the mitigation we offer for Council consideration will result in no material typical bill impact.

Mitigation Credits

ENO is holding funds that are disbursable to ratepayers at the Council's direction: (i) Funds related to overcollection of Rider SSCR: $1,623,298,[49] and (ii) $32.0 million related to a settlement of litigation related to SERI.[50] Considering all revenue changes and Advisor recommendations,

[47] *See* ENO's April 2025 Rider PPCR filing, WP3, which presents applicable base revenues by month.

[48] *See* ENO's response to DR CNO 3-10 for the ENO Accounts and their adjusted balances.

[49] See ENO's April 17, 2025 letter to the Council, Re: Entergy New Orleans Storm Recovery Funding Distribution Repayment.

[50] *See* Council Resolution No. R-24-194, AIP paragraph 6.a at 2. Of note, disbursement of more than $10 million of these credits in any twelve-month period requires collaboration with ENO.

ENO's electric revenues would increase by $4.4 million without mitigation. In the interest of rate stability and the equitable use of these available credits, we recommend that the Council allow ENO to apply a $4.4 million credit to the calculation of FRP rates. Specifically, we recommend that the full $1.6 million related to Rider SSCR be applied, with the remainder of the required mitigation applied from the SERI settlement regulatory liability. Further, as the PPCR realignment has a disparate impact affecting Residential rates, in the interest of rate stability and equity, we recommend that this credit be applied to residential FRP rates.

The application of $4.4 million in mitigation credits to Residential FRP rates, in addition to the Advisors' recommended adjustments, will result in no overall change to ENO electric revenues and no material change to Residential typical bills (when measured over a twelve-month period).

As such, we have adjusted ENO's FRP Evaluation Filing with a mitigation credit of $4.4 million to the Residential rate class.

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	$181,702,781	($1,664,057)	-0.9%
Small Electric Service	72,876,039	(2,517,537)	-3.5%
Municipal Buildings	3,129,921	3,536,059	113.0%
Large Electric	25,164,822	(2,298,589)	-9.1%
Large Electric High Load Factor	94,827,767	(3,000,840)	-3.2%
Master Metered Non-Residential	504,152	50,351	10.0%
High Voltage	5,695,339	32,587	0.6%
Large Interruptible	3,795,467	(307,764)	-8.1%
Large Municipal	1,441,998	(108,259)	-7.5%
Lighting Service	3,979,682	(1,248,596)	-31.4%
Total	$393,117,968	($7,526,646)	-1.9%

We also reproduce ENO's proposed overall revenue change: proposed FRP revenues plus Rider PPCR realignment revenues in Table 2a below.

Table 2a (reproduced from above) ENO Overall Revenue Filing Change in Electric FRP Revenues			
Rate Class	Applicable Base Revenue	Proposed Change in FRP and Rider PPCR Revenue	Proposed Change in FRP Revenue as Percent of Base Revenue
Residential	$181,702,781	$7,108,689	3.9%
Small Electric Service	72,876,039	493,640	0.7%
Municipal Buildings	3,129,921	3,644,370	116.4%
Large Electric	25,164,822	(813,203)	-3.2%
Large Electric High Load Factor	94,827,767	2,188,472	2.3%
Master Metered Non-Residential	504,152	52,519	10.4%
High Voltage	5,695,339	426,500	7.5%
Large Interruptible	3,795,467	(174,842)	-4.6%
Large Municipal	1,441,998	(108,259)	-7.5%
Lighting Service	3,979,682	(1,164,854)	-29.3%
Total	$393,117,968	$11,653,031	3.0%

Table 8 Advisor Adjusted Electric Change in FRP Revenues (Excluding Mitigation Credits)			
Rate Class	Applicable Base Revenue	Advisor Adjusted Change in EFRP Revenue	Adjusted Change in EFRP Revenue as Percent of Applicable Base Revenue
Residential	$181,702,781	($4,601,984)	-2.5%
Small Electric Service	72,876,039	(4,220,965)	-5.8%
Municipal Buildings	3,129,921	(80,976)	-2.6%
Large Electric	25,164,822	(1,933,706)	-7.7%
Large Electric High Load Factor	94,827,767	(2,461,064)	-2.6%
Master Metered Non-Residential	504,152	84,763	16.8%
High Voltage	5,695,339	(315,449)	-5.5%
Large Interruptible	3,795,467	(97,091)	-2.6%
Large Municipal	1,441,998	(26,510)	-1.8%
Lighting Service	3,979,682	(1,103,270)	-27.7%
Total	$393,117,968	($14,756,252)	-3.8%

Of note, the above table does not reflect the approximate $19.2 million increase in Rider PPCR Revenues. Table 8a below reflects ENO's overall electric revenue change with Advisor adjustments.

Table 8a Advisor Adjusted Electric Change in Electric Revenues (Including PPCR Realignment, Excluding Mitigation Credits)			
Rate Class	Applicable Base Revenue	Advisor Adjusted Change in EFRP Revenue	Adjusted Change in EFRP Revenue as Percent of Applicable Base Revenue
Residential	$181,702,781	$4,170,762	2.3%
Small Electric Service	72,876,039	(1,209,788)	-1.7%
Municipal Buildings	3,129,921	27,335	0.9%
Large Electric	25,164,822	(448,320)	-1.8%
Large Electric High Load Factor	94,827,767	2,728,248	2.9%
Master Metered Non-Residential	504,152	86,931	17.2%
High Voltage	5,695,339	78,464	1.4%
Large Interruptible	3,795,467	35,830	0.9%
Large Municipal	1,441,998	(26,510)	-1.8%
Lighting Service	3,979,682	(1,019,528)	-25.6%
Total	$393,117,968	$4,423,425	1.1%

The above Table 8a indicates an overall Advisor-adjusted electric revenue increase of $4.4 million. As we discuss earlier in this report, we recommend a residential mitigation credit equal to this $4.4 million revenue increase.

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 gas FRP 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	$23,611,307	$351,497	1.5%
Small General	5,351,022	76,660	1.5%
Large General	5,378,495	80,069	1.5%
Small Municipal	50,442	751	1.5%
Large Municipal	1,702,783	25,349	1.5%
Total	$36,094,050	$537,325	1.5%

Table 9 Advisor Adjusted Gas Change in FRP Revenues			
Rate Class	Applicable Base Revenue	Advisor Adjusted Change in FRP Revenue	Proposed Change in FRP Revenue as Percent of Base Revenue
Residential	$23,611,307	$ -	0.0%
Small General	5,351,022	-	0.0%
Large General	5,378,495	-	0.0%
Small Municipal	50,442	-	0.0%
Large Municipal	1,702,783	-	0.0%
Total	$36,094,050	$ -	0.0%

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 (April Measurement, No Mitigation)					
Rate Class	Energy (kWh)	Present	ENO Proposal	After Advisor Adjustments	Change from ENO Proposal
Residential	1,000	$155.94	$160.96	$159.63	($1.33)
Small Electric	9,125	$1,563	$1,576	$1,555	($21)
Large Electric	91,250	$12,055	$11,823	$11,918	($137)

Table 10a presents typical bill impacts, but with the PPCR realignment calculated across a twelve-month period. As we discussed earlier in this report, and specific to the instant FRP Evaluation, we consider an annual PPCR realignment effect a better measure of ratepayer impact than a single month measure.

Table 10a Estimated Change to Typical Electric (Legacy) Customer Monthly Bill (Annual PPCR Realignment Measurement, No Mitigation)					
Rate Class	Energy (kWh)	Present	ENO Proposal[1]	After Advisor Adjustments	Change from ENO Proposal
Residential	1,000	$155.94	$159.26	$157.93	($1.33)
Small Electric	9,125	$1,563	$1,569	$1,547	($22)
Large Electric	91,250	$12,055	$11,783	$11,878	($95)

1. Proposed typical bills reflect ENO's proposed rates, but with Rider PPCR's proposed rate to reflect a twelve-month realignment of credits as opposed to an April 2025 measurement.

Table 10b below presents the same overall Advisor-adjusted electric typical bills, but with also reflecting a $4.4 million Residential mitigation credit.

Table 10b Estimated Change to Typical Electric (Legacy) Customer Monthly Bill (Annual PPCR Realignment Measurement, $4.4 Million Residential Mitigation)					
Rate Class	Energy (kWh)	Present	ENO Proposal[1]	After Advisor Adjustments	Change from ENO Proposal
Residential	1,000	$155.94	$159.26	$155.93	($3.33)
Small Electric	9,125	$1,563	$1,569	$1,547	($22)
Large Electric	91,250	$12,055	$11,783	$11,878	($95)

1. Proposed typical bills reflect ENO's proposed rates, but with Rider PPCR's proposed rate to reflect a twelve-month realignment of credits as opposed to an April 2025 measurement.

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

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	$78.11	$78.51	$78.11	($0.40)
Small General	500 ccf	$627	$630	$627	($3)
Large General	1,000 mcf	$10,833	$10,873	$10,833	($40)

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

Mark to Market or "MTM" is an optional tax position under IRC Sec. 475 that allows ENO to record a balance sheet entry based on the expected costs of Purchase Power Agreement ("PPA") contracts relative to market costs for the same capacity and energy. ENO is not obligated to undertake MTM accounting and tax positions, but should ENO opt for MTM treatment, all contracts must be given MTM treatment. As ENO's taxable income and taxable deductions are part of a consolidated return involving other companies, it is our understanding that ENO's MTM election is tied to the broader interests of the consolidated taxable entity (*i.e.*, the EOCs as a whole).

In the instant FRP Evaluation Filing, per book MTM balances are recorded in ENO Accounts 283225 – ($10,375,917) and 283226 ($4,006,145) (credit balances). These values are largely allowed by ENO to credit ENO's rate base, except for de minims, but inappropriate, reversals through what ENO calls FIN 48 adjustments.[51] In the instant FRP Evaluation Filing, MTM ADIT is a credit (*i.e.*, a reduction to rate base). However, in prior FRP Evaluation Filings, MTM has been a debit.

In the 2024 FRP Evaluation Filing, ENO recorded debit MTM balances. As part of ENO Adjustment AJ03A.3, ENO credited ENO Accounts 283225 and 283226 to remove debit ADIT balances from ENO's rate base.

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

51 *See* ENO's HSPM response to DRs CNO 1-22 and CNO 4-2.

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."[52]

ENO requests here that ratepayers compensate ENO for its optional MTM tax positions that in some years would increase rates should their ADIT be allowed in rate base. ENO should only undertake tax positions that provide useful capital (i.e., a credit to rate base). 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.

To the extent the sharing of tax burdens among ENO's Affiliates is not practicable, we note, for discussion purposes, a compromise treatment for Council consideration in an appropriate proceeding, which we describe below.

A hypothetical treatment: in years in which a debit rate base balance related to a particular MTM tax position may occur, the revenue requirement (at ENO's WACC for FRP purposes) related to that debit balance may be deferred as a regulatory asset that is not reflected in rate base and that does not amortize. The similar revenue requirement related to future MTM credit rate base balances may be used to credit the position's regulatory asset before such revenue requirement credit flows to rates. This way, ENO does not credit ratepayers in some years, while absorbing debit balances in other years. However, ratepayers cannot be penalized for MTM tax positions; they can only benefit. Additionally, once any contract subject to MTM accounting terminates, any regulatory asset balance related to the terminated contract would be written off from any deferral balance without affecting ENO's rates.

Meter Reading Expense

In ENO's 2022 FRP Evaluation Filing, ENO's proformed 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 2024 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 $0.1 million electric[53] (down from $0.3 million in 2024) and $0.3 million gas[54] (approximately unchanged from 2024).

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."[55] While the stated goal is for all meter reading and nearly all meter services to be performed remotely, the Advisors are encouraged by the downward change in electric meter reading expenses. We note that as of July 1, 2025, ENO no longer owns or operates the New Orleans gas utility, and any future progress regarding the gas utility is the responsibility of the new owner, Delta New Orleans Gas Company, LLC.

52 FRP Evaluation Filing, *Summary Pleading,* XXXV and XXXVI.at 22.

53 *See* EX1 – O&M_E, EX1.1-1.3, line 110.

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

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

ENO discusses challenges in completing its AMI meter deployment, stating, "The non-AMI meters remaining after the completion of mass deployment present additional challenges, including limited access to the meter location or the need for customer-initiated upgrades to the meter base before installation can occur."[56]

While outside the scope of a FRP evaluation, ENO's AMI investment, whose costs it continues to recover from ratepayers, has fallen somewhat 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 continue to monitor the performance of ENO's AMI program relative to the representations made by ENO in Docket No. UD-16-04.

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 Present Revenues by $11.3 million (which represented a decrease to ENO's FRP revenue requirement).

As part of our review of the instant FRP Evaluation Filing, we identified no significant non-typical conditions affecting ENO's revenues. As such, per the text of Rider EFRP-7, which generally calls for the use of actual test year revenues, we do not recommend any adjustments to ENO's Present Revenues related to non-typical conditions. As we discuss earlier in this report, ENO has included proforma electric revenues for the Large Municipal rate class. We find this proforma necessary and reasonable for the instant FRP evaluation, and this proforma does not change our conclusion that no adjustment to ENO's revenues related to a non-typical test year is required as part of our review of the FRP Evaluation Filing.

[56] ENO's response to DR CNO 4-5.

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, 2024

Line No.	Description	Total Company Adjusted	Residential	Small Electric	Municipal	Large Electric	High Load Factor	Master Metered	High Voltage	Large Interruptible	Large Municipal	Lighting
[a]	[b]	[c]	[d]	[e]	[f]	[g]	[h]	[i]	[j]	[k]	[l]	[m]
1	Rate Base	1,162,166,496	657,370,329	166,104,913	21,233,979	63,544,585	225,470,088	1,311,660	9,108,431	6,178,281	2,304,811	9,539,419
2	ENO Required Rate of Return on Rate Base After taxes	7.35%										
3	ENO Required Rate of Return on Rate Base Including taxes	9.10%	3.48%	20.62%	18.38%	12.49%	14.54%	19.79%	16.09%	2.79%	9.02%	20.13%
4	Return on Rate Base including income taxes	105,757,151	22,868,573	34,247,428	3,902,192	7,934,159	32,779,253	259,539	1,465,741	172,438	207,873	1,919,955
5	Operation & Maintenance Expense	458,117,856	235,414,146	63,759,823	3,486,269	28,633,885	108,101,712	557,888	8,748,355	6,238,214	1,392,235	1,785,329
6	Gains from Disp of Allowances	-	-	-	-	-	-	-	-	-	-	-
7	Regulatory Debits & Credits	(5,212,162)	(3,068,373)	(739,348)	(92,601)	(263,953)	(932,851)	(5,400)	(34,546)	(19,935)	(8,647)	(46,507)
8	Interest on Customer Deposits	2,236,707	1,265,175	319,687	40,868	122,298	433,939	2,524	17,530	11,890	4,436	18,360
9	Other Credit Fees	39,504	22,345	5,646	722	2,160	7,664	45	310	210	78	324
10	Depreciation & Amortization Expense	77,738,439	44,864,139	11,155,259	1,265,796	4,087,951	14,432,847	81,224	623,535	418,312	152,996	656,382
11	Amortization of Plant Acquisition Adjustment	1,190,642	600,202	179,884	6,282	77,261	281,216	1,643	24,014	13,861	6,279	-
12	Taxes Other than Income	20,113,153	11,540,992	2,917,683	303,954	1,058,192	3,775,406	21,811	179,726	122,497	45,762	147,130
13	Adjustment (Bad Debt, Reg. Exp. & Tax Difference)	(996,943)	(181,037)	(287,151)	12,108	(97,384)	(361,584)	(895)	(39,357)	(28,681)	(10,285)	(2,677)
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	(60,953,785)	(26,964,085)	(9,384,644)	(521,776)	(4,134,563)	(16,555,917)	(86,234)	(1,423,225)	(1,339,573)	(38,701)	(505,066)
19	**Total Cost of Service**	**598,030,563**	**286,362,077**	**102,174,266**	**8,403,812**	**37,420,007**	**141,961,686**	**832,143**	**9,562,082**	**5,589,234**	**1,752,025**	**3,973,231**
20	Less Present Revenue [1]	611,803,715	291,246,486	105,809,586	4,920,282	40,122,493	146,457,611	531,817	9,604,031	5,946,241	1,879,156	5,286,012
21	**= Revenue Deficiency (Excess)**	**(13,773,153)**	**(4,884,409)**	**(3,635,320)**	**3,483,529**	**(2,702,487)**	**(4,495,925)**	**300,326**	**(41,949)**	**(357,007)**	**(127,131)**	**(1,312,781)**
22	Percent Increase on Total Revenues	-2.3%	-1.7%	-3.4%	70.8%	-6.7%	-3.1%	56.5%	-0.4%	-6.0%	-6.8%	-24.8%

Attachment B

Attachment B
Corrected Return on Rate Base
Calculation by Rate Class

Description	Line Item	Total Advisor Adjustments	Combined Total Company Adjusted	Residential	Small Electric	Municipal	Large Electric	High Load Factor	Master Metered	High Voltage	Large Interruptible	Large Municipal	Lighting
Rate Base	RBTOA: RATE BASE Total	(3,298,530)	1,158,867,965	651,357,315	166,615,545	14,717,815	66,362,734	232,374,023	1,457,097	9,159,854	6,555,112	2,409,747	7,858,724
ENO Required Rate Of Return On Rate Base Including Taxes	RORB IT	9.10%	9.10%	3.38%	20.97%	9.44%	12.98%	14.75%	1.00%	16.27%	4.20%	13.50%	26.93%
Return On Rate Base Including Income Taxes		(300,166)	105,456,985	22,020,268	34,935,728	1,389,385	8,612,142	34,276,737	14,571	1,490,757	275,315	325,412	2,116,669
Operation & Maintenance Expense	OMTOA: OPERATION & MAINTENANCE EXPENSE Total	0	458,117,856	237,082,182	62,526,256	2,822,907	28,594,179	108,383,797	579,126	8,492,740	6,383,836	1,382,449	1,870,384
Regulatory Debits & Credits	RDCTOA: REGULATORY DEBITS AND CREDITS Total	(2,045,197)	(7,257,359)	(4,230,166)	(1,036,725)	(142,486)	(368,364)	(1,308,776)	(7,256)	(54,500)	(30,900)	(13,290)	(64,897)
Interest on Customer Deposits	ICDTOA: INTEREST ON CUSTOMER DEPOSITS Total	0	2,236,707	1,261,013	321,790	26,176	128,637	447,940	2,860	16,637	12,256	4,402	14,996
Other Credit Fees	OCFTOA: OTHER CREDIT FEES Total	40,559	80,063	45,138	11,518	937	4,605	16,034	102	596	439	158	537
Depreciation & Amortization Expense	DXTOA: DEPRECIATION AND AMORTIZATION EXPENSE Tot	(157,555)	77,580,884	44,705,248	11,170,309	932,237	4,221,466	14,702,466	88,697	599,914	426,632	151,850	582,066
Amortization of Plant Acquisition Adjustment	APAATOA: AMORTIZATION OF PLANT ACQUISITION ADJUS	0	1,190,642	608,281	175,017	4,556	76,269	280,674	1,702	22,955	14,140	6,227	822
Taxes Other than Income	TOTOA: TAXES OTHER THAN INCOME Total	0	20,113,153	11,540,992	2,917,683	303,954	1,058,192	3,775,406	21,811	179,726	122,497	45,762	147,130
Adjustment (Bad Debt, Reg. Exp. & Tax Difference)	Adjustment (Bad Debt, Reg. Exp. & Tax Difference)	(12,150)	(1,009,093)	(183,244)	(290,650)	12,255	(98,570)	(365,991)	(906)	(39,837)	(29,030)	(10,411)	(2,709)
SSCR II (recovered w/ a Rider)													
SSCO (recovered w/ a Rider)													
Less Credit To COS From Other Operating Revenue:		0	(60,953,785)	(26,964,085)	(9,384,644)	(521,776)	(4,134,563)	(16,555,917)	(86,234)	(1,423,225)	(1,339,573)	(38,701)	(505,066)
Total Cost Of Service		(2,474,510)	595,556,053	285,885,627	101,346,281	4,828,146	38,093,992	143,652,371	614,472	9,285,763	5,835,611	1,853,857	4,159,932
EAC Revenues	*REVEAC: EAC Revenues*		*1,262*	*60*	*295*	*11*	*148*	*624*	*3*	*59*	*53*	*0*	*10*
FAC Revenues	*REVFAC: FAC Revenues*	(347,640)	*77,609,280*	*32,129,956*	*11,859,590*	*528,462*	*5,480,527*	*22,579,270*	*105,631*	*2,186,909*	*2,086,147*	*1,500*	*651,288*
FRP Revenue	*REVFRP: FRP Revenue*	-	*104,737,753*	*50,495,021*	*22,245,848*	*968,604*	*7,478,381*	*21,386,886*	*(73,039)*	*1,269,041*	*(14,020)*	*321,307*	*659,724*
LCFC Revenue	*REVLCF: LCFC Revenue*	269,599	*(5,180,765)*	*(2,563,854)*	*(936,502)*	*(41,065)*	*(322,921)*	*(1,218,365)*	*(6,469)*	*(73,084)*	-	*(18,504)*	-
MISO Revenues	*REVMIS: MISO Revenues*	38,666	*5,377,776*	*2,747,294*	*787,183*	*19,611*	*335,034*	*1,255,848*	*6,718*	*103,468*	*93,596*	*25,526*	*3,498*
Purchase Power Revenues	*REVPPC: Purchase Power Capacity*	556,323	*(2,380,652)*	*(1,152,667)*	*(424,733)*	*(24,703)*	*(145,066)*	*(533,407)*	*(839)*	*(58,563)*	*(19,193)*	*(12,496)*	*(8,984)*
Sales Revenue	*REVOTH: Sales Revenue*	-	*411,505,202*	*199,797,679*	*72,980,347*	*3,200,126*	*25,164,822*	*94,945,591*	*504,152*	*5,695,339*	*3,795,467*	*1,441,998*	*3,979,682*
	456200: Unbilled Revenue	-	-	-	-	-	-	-	-	-	-	-	-
EECR Revenue	*REVEEC: EECR Revenue*	117,167	*20,767,849*	*10,128,747*	*(605,362)*	*276,478*	*2,172,374*	*8,183,210*	*(4,255)*	*492,070*	-	*124,587*	-
Present Revenue		634,115	612,437,706	291,582,235	105,906,665	4,927,525	40,163,299	146,599,657	531,901	9,615,238	5,942,049	1,883,919	5,285,218
FRP Revenue Change		**(3,108,625)**	**(16,881,652)**	**(5,696,608)**	**(4,560,384)**	**(99,378)**	**(2,069,307)**	**(2,947,286)**	**82,572**	**(329,475)**	**(106,438)**	**(30,061)**	**(1,125,286)**
			-2.76%	-1.95%	-4.31%	-2.02%	-5.15%	-2.01%	15.52%	-3.43%	-1.79%	-1.60%	-21.29%

Of note regarding Attachment B, the Advisor Adjustments totaling \$3.1 million do not include the reversal of \$4.1 million in LPC revenue realignment.

Attachment C

Advisor Adjustments to ENO's Proposed Ratemaking Treatment by Account		
ENO Account(s)	**Electric Adjustment DR/(CR)**	**Gas Adjustment DR/(CR)**
ADV01 – Rider Revenues		
RSRREAC: 440-445 SALES–RETAIL – EAC	$125	
RSRREECR: 440-445 SALES–RETAIL - Energy Smart	($117,167)	
RSRRFAC: 440-445 SALES–RETAIL - FAC	$347,640	
RSRRMIS: 440-445 SALES–RETAIL - MISO	($38,666)	
RSRRPPC: 440-445 SALES–RETAIL - PURCHASED POWER CAPACITY	($556,323)	
PGA Rider Revenue		$303,970
FTCALC: FEDERAL INCOME TAX	$72,313	($60,323)
CITTOA: CURRENT INCOME TAXES	$20,042	($16,718)
ADV03 – LCFC		
RSRRLCF: 440-445 SALES–RETAIL - LCFC REVLCF: LCFC Revenue	($269,599)	
ADV04 – Storm Proforma Costs		
PLD361: 361 STRUCTURES & IMPROVEMENTS (DS-DD-TO) 1010AM: Electric Plant In Service	($34,584)	
PLD362: 362 STATION EQUIPMENT (DS-DD-TO) 1010AM: Electric Plant In Service	($979,265)	
PLD364: 364 POLES, TOWERS, & FIXTURES (D2-DD-TO) 1010AM: Electric Plant In Service	($902,894)	
PLD365: 365 OVERHEAD CONDUCTORS & DEVICES (D2-DD-TO) 1010AM: Electric Plant In Service	($1,488,934)	
PLD368: 368 LINE TRANSFORMERS (DX-DD-TO) 1010AM: Electric Plant In Service	($1,497,507)	
PLD3691: 369.1 OVERHEAD SERVICES (DV-CC-TO) 1010AM: Electric Plant In Service	($440,544)	
DXD361: 361 STRUCTURES & IMPROVEMENTS (DS-DD-TO) 4030AM: Depreciation Expense	($332)	
DXD362: 362 STATION EQUIPMENT (DS-DD-TO) 4030AM: Depreciation Expense	($10,638)	
DXD364: 364 POLES, TOWERS, & FIXTURES (D2-DD-TO) 4030AM: Depreciation Expense	($28,581)	
DXD365: 365 OVERHEAD CONDUCTORS & DEVICES (D2-DD-TO) 4030AM: Depreciation Expense	($47,711)	
DXD368: 368 LINE TRANSFORMERS (DX-DD-TO) 4030AM: Depreciation Expense	($56,548)	
DXD3691: 369.1 OVERHEAD SERVICES (DV-CC-TO) 4030AM: Depreciation Expense	($13,746)	
ADV05 – FIN 48 Interest		
OCFBL: BANK LOANS & FIN48 - INTEREST EXP	$40,559	

Attachment C

Advisor Adjustments to ENO's Proposed Ratemaking Treatment by Account		
ENO Account(s)	**Electric Adjustment DR/(CR)**	**Gas Adjustment DR/(CR)**
ADV08 – UPITA		
254120: 254 REGULATORY LIABILITY	$1,200,143	$843,387
RC407: 407.403 REGULATORY CREDITS	($1,200,143)	($843,387)
ADV09 – Income Tax Overcollection		
254120: 254 REGULATORY LIABILITY	$845,054	$141,980
RC407: 407.403 REGULATORY CREDITS	($845,054)	($141,980)

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, 2024

Line No.	Description		ENO Adjusted Amount	Advisor Adjusted Amount
	TOTAL COMPANY			
1	RATE BASE	Att B, P 2, L 23	1,162,166,496	1,158,867,965
2	BENCHMARK RATE OF RETURN ON RATE BASE	Att D, L 4, Col D	7.35%	7.35%
3	REQUIRED OPERATING INCOME	L 1 * L 2	85,442,481	85,199,973
4	NET UTILITY OPERATING INCOME	Att B, P 3, L 26	95,889,083	98,004,297
5	OPERATING INCOME DEFICIENCY/(EXCESS)	L 3 - L 4	(10,446,602)	(12,804,324)
6	REVENUE CONVERSION FACTOR (1)		1.3184	1.3184
7	REVENUE DEFICIENCY/(EXCESS)	L 5 * L 6	(13,773,153)	(16,881,652)
	PRESENT RATE REVENUES			
8	ULTIMATE CUSTOMERS	Att B, P 3, L 1	611,803,715	612,437,706
9	REVENUE REQUIREMENT	L 7 + L 8	598,030,563	595,556,053
10	PRESENT RATE BASE REVENUES	Att B, P 3, L 1	611,803,715	612,437,706
11	REVENUE DEFICIENCY/(EXCESS)	L 9 - L 10	(13,773,153)	(16,881,652)
12	REVENUE CONVERSION FACTOR (1)	L 6	1.3184	1.3184
13	OPERATING INCOME DEFICIENCY/(EXCESS)	L 11/L 12	(10,446,602)	(12,804,324)
14	RATE BASE	Att B, P 2, L 23	1,162,166,496	1,158,867,965
15	COMMON EQUITY DEFICIENCY/(EXCESS) (%)	L 13/L 14	-0.90%	-1.10%
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	6.04%	6.25%
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	10.98%	11.36%

Of note, the Advisor Adjusted amounts in the above schedule do not reflect the Advisors' recommended mitigation credits totaling $4.5 million (ADV10).

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, 2024

Line No.	Description		ENO Filing Adjusted Amount	Advisor Adjusted Amount
	TOTAL COMPANY			
1	RATE BASE	Att B, P 2, L 18	213,436,954	214,422,322
2	BENCHMARK RATE OF RETURN ON RATE BASE	Att D, L 4, Col D	7.35%	7.35%
3	REQUIRED OPERATING INCOME	L 1 * L 2	15,691,885	15,764,329
4	NET UTILITY OPERATING INCOME	Att B, P 3, L 24	15,239,911	15,998,350
5	OPERATING INCOME DEFICIENCY/(EXCESS)	L 3 - L 4	451,974	(234,020)
6	REVENUE CONVERSION FACTOR (1)		1.3465	1.3465
7	REVENUE DEFICIENCY/(EXCESS)	L 5 * L 6	608,573	(315,103)
	PRESENT RATE REVENUES			
8	ULTIMATE CUSTOMERS	Att B, P 3, L 1	99,942,180	100,700,619
9	REVENUE REQUIREMENT	L 7 + L 8	100,550,752	100,385,515
10	PRESENT RATE REVENUES	Att B, P 3, L 1	99,942,180	100,700,619
11	REVENUE DEFICIENCY/(EXCESS)	L 9 - L 10	608,573	(315,103)
12	REVENUE CONVERSION FACTOR (1)	L6	1.3465	1.3465
13	OPERATING INCOME DEFICIENCY/(EXCESS)	L 11/L 12	451,974	(234,020)
14	RATE BASE	Att B, P 2, L 18	213,436,954	214,422,322
15	COMMON EQUITY DEFICIENCY/(EXCESS)	L 13/L 14	0.21%	-0.11%
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	4.93%	5.25%
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	8.96%	9.55%