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July 14, 2023

BY E-MAIL

Brian L. Guillot
Mr. Edward R. Wicker, Jr.
Legal Services - Regulatory
Entergy Services, LLC
639 Loyola Ave., 26th Floor
New Orleans, LA 70113

Re: Entergy New Orleans, LLC's Formula Rate Plan Test Year 2022 Evaluation Pursuant to Council Resolution Nos. R-19-457 and R-20-344, Rider EFRP-6 and GFRP-6, Docket UD-18-07

Dear Brian and Ed:

Attached please find the Advisors to the Council of the City of New Orleans' *Investigation and Review of Entergy New Orleans, LLC's 2023 Electric and Gas Formula Rate Plans Evaluation Filings* in the above-referenced matter.

Best regards,

Jay Beatmann

JAB:dm
Attachment

cc: Official Service List for UD-18-07

INVESTIGATION AND REVIEW
OF
ENTERGY NEW ORLEANS, LLC'S 2023 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, AND R-21-295

DOCKET NO. UD-18-07

JULY 14, 2023

Legend Consulting Group Limited

INTRODUCTION

On April 28, 2023, Entergy New Orleans, LLC's ("ENO") submitted to the Council its *Entergy New Orleans, LLC's 2023 Electric and Gas Formula Rate Plan Filings* ("FRP Evaluation Filing" or "instant FRP Evaluation Filing") for the twelve-month evaluation period ending December 31, 2022 ("2022 Test Year") to initiate new electric and gas rates effective with the first billing cycle of September 2023. 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 $7.0 million and reduce the proposed gas revenue increase by $1.3 million. The Advisors also suggest certain mitigation measures that could reduce the rate impact on electric ratepayers by $12.1 million while still allowing ENO a reasonable opportunity to recover its costs and earn the Council-approved rate of return. The FRP Evaluation Filing Decoupling approach results in a $7.90 increase[1] on the typical residential electric bill, while ENO's recommended alternative approach results in a $3.79 increase on the typical residential electric bill. The combined effect of the Advisors' recommended corrections and mitigation measures results in a $4.04 decrease compared to this alternative method, which is a $0.24 decrease compared to present rates,[2] The Advisors' recommendations reduce ENO's proposed $5.85 increase on the typical residential gas bill by $0.92, which is a $4.93 increase compared to present rates.

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[3] (*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 $7.90.

2 Even though ENO's electric FRP revenues increase based on our recommendations, ENO's rates presently reflect $4.7 million in outside-the-bandwidth revenues that will expire with the new rates in the instant FRP Evaluation. The expiration of these revenues offset our corrected and mitigated revenue increase to yield the decrease in typical bills.

3 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",[4] 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 ROE of 9.35%.[5]

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.

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 $7.0 million for the electric utility and $1.3 million for the gas utility. However, even with these Advisor Adjustments, the magnitude of the EFRP (*i.e.*, electric) rate increases will still result in a significant bill increase to ratepayers. Accordingly, while the Parties are only directed to identify errors in the filing, we feel that the magnitude of ENO's proposed electric revenue requirement increase and its impact on ratepayers necessitates a review of other potential ratepayer impact mitigation measures in addition to the identification of errors.

Four sources of funds for mitigation that are available with respect to electric customers are monies currently being held by ENO pending Council direction. These monies, totaling roughly $47.7 million, could be utilized by the Council, unilaterally, to reduce the magnitude of the Rate Adjustment beyond the errors that are ultimately identified and agreed to by the Parties.

- *Refunds from FERC Docket No. EL18-152.* $34,838,880. Due to the Council's long-term efforts to ensure just and reasonable rates before the Federal Energy Regulatory Commission ("FERC"), ENO received a total of $34,838,880 in refunds that are available

4 FRP Evaluation Filing, Summary Pleading at 4

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.

for disbursement for ratepayer benefit at the Council's direction,[6] but SERI has sought reconsideration of this order,[7] which we discuss later in this report as affecting our recommended use of these funds. This $34,838,880 refund amount relates to two issues addressed in FERC Docket No. EL18-152:

- *Sale-Leaseback Renewal Rental Expense*. FERC ordered that System Energy Resources, Inc. ("SERI") could not recover through Unit Power Sales Agreement ("UPSA") billings its costs related to a lease renewal on approximately 11.5% of SERI's ownership of the Grand Gulf Nuclear Station ("Grand Gulf"). This refund amount to ENO, including FERC interest, was $29,500,743.

- *Depreciation Rate Corrections*. FERC ordered corrections to SERI's calculation of depreciation expenses as billed under UPSA on plant related to its leasehold interest in Grand Gulf. This refund amount to ENO, including FERC interest, was $4,513,605.

Of note, this $34,838,880 amount is inclusive of "applicable interest" as of April 30, 2023[8] that continues to accrue. ENO has stated this credit's amount as of August 31, 2023 as being HSPM in its response to Data Request ("DR") CNO 4-1.

- *EAC Rate Adjustment Deferral* $1,499,000. In December 2022, ENO received a one-time credit related to the sale of certain surplus Cross-State Air Pollution Rule ("CSAPR") NOx Group 3 Allowances, which the Council directed ENO to retain for later ratepayer benefit. These funds are available for disbursement for ratepayer benefit at the Council's direction.

- *Partial Settlement in FERC Docket No. EL20-72* $6,378,438. The Council, along with the other retail regulator complainants in this FERC proceeding reached a settlement of certain issues that were set for trial. The remaining issues are before FERC and the date of its final determination is unknown.

- *SERI Depreciation Refund from FERC Docket No. ER21-736* Approximately $5 million. In FERC Docket No. ER21-736, SERI requested an increase to its allowed depreciation rates, which are a component of SERI's billings to ENO. Per FERC procedures, SERI's requested rates became effective May 2022 while settlement discussions were underway. A settlement arriving at deprecation rates lower than those requested by SERI was reached, with new rates implemented June 2023. A refund is due ENO for excess billings during this 13-month period, but ENO failed to provide an estimate of this amount.[9] Based on our review of available data, ENO's refund will be in the rough range of $5 million.

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

[6] ENO states that the available amount of this credit as of April 30, 2023 was $34,838,880; *See* DR CNO 1-14.
[7] *See* SERI's Petition for Review before the United States Court of Appeals for the Fifth Circuit, March 6, 2023.
[8] ENO's response to DR CNO 1-14
[9] *See* ENO's response to DR CNO 4-1.

Table 1 Summary of Advisor Recommended Adjustments ($ in Millions)		
	Electric	Gas
ENO Proposed FRP Revenue Increase	$17.4	$8.2
Agreed-to Outside-the-Bandwidth Revenues	$3.4	$0.0
ENO Proposed Incremental FRP Revenues	**$20.8**	**$8.2**
Advisor Adjustments		
Advisor Adjustments to Evaluation Report	($7.0)	($1.3)
Advisor Recommended Bill Mitigation Measures	($12.1)	
Total Advisor Recommended Adjustments and Mitigations	($19.1)	($1.3)
Revenue Increase After Advisor Adjustments	**$1.7**	**$6.9**
Percent Change to ENO's Proposed Revenue Increase	(91.8%)	(15.8%)

In addition to these Advisor Adjustments and recommended bill mitigation measures, 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 2023) 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. In its EFRP Evaluation Filing, ENO applied decoupling in initially determining customer class revenue requirement allocations. However, noting that its application of decoupling had "…a disproportionate effect on the Residential and Municipal Buildings rate classes",[10] ENO proposed alternative Electric FRP Rate Adjustments ("ENO Alternative Proposal") that did not incorporate decoupling. It is the proposed alternative Electric FRP Rate Adjustments for which ENO is requesting Council approval.

Table 2 presents the as-filed FRP Evaluation Filing electric revenue change by rate class.[11]

10 FRP Evaluation Filing, Summary Pleading, Paragraph VII at 10

11 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[1]	Proposed Change in FRP Revenue as Percent of Base Revenue
Residential	$182,062,241	$19,072,783	10.5%
Small Electric Service	71,676,686	(7,408,999)	(10.3%)
Municipal Buildings	2,086,553	1,923,062	92.2%
Large Electric	25,237,611	(3,743,488)	(14.8%)
Large Electric High Load Factor	94,646,849	10,523,824	11.1%
Master Metered Non-Residential	605,840	50,610	8.4%
High Voltage	5,531,634	11,056	0.2%
Large Interruptible	3,977,229	476,126	12.0%
Lighting Service	4,020,700	(82,744)	(2.1%)
Total	389,845,342	20,822,230	5.3%

1 This $20.8 million total proposed change in FRP revenue includes the agreed-to outside-the-bandwidth electric revenue of $3.4 million.

Of note, ENO's FRP Evaluation Filing Decoupling assigns 92% of ENO's proposed $20.8 million increase in electric revenues to residential customers. Through discovery, we were not provided with sufficient data to identify the cause of this seemingly anomalous result. While ENO attempts to resolve this result with the ENO Alternative Proposal, we do not believe that the ENO Alternative Proposal is appropriate in that it fails to adhere to the Council's decoupling requirement per Council Resolution No. R-19-457.

Table 2a presents the ENO Alternative Proposal electric revenue change by rate class.[12]

[12] ENO's supporting work paper indicates that ENO's Alternative Proposal EFRP revenue adjustment was apportioned to customer classes on base revenue, not including the EFRP exclusions or annualized EFRP revenue (accumulated EFRP revenue adjustments since the rate case). No additional exhibits were provided similar to Evaluation Attachment G, presenting customer classes rates of return corresponding to the Alternate Proposal.

Table 2a ENO Alternative Proposal Change in Electric FRP Revenues			
Rate Class	Applicable Base Revenue	Proposed Change in FRP Revenue[1]	Proposed Change in FRP Revenue as Percent of Base Revenue
Residential	$182,062,241	$9,944,743	5.5%
Small Electric Service	71,676,686	3,536,196	4.9%
Municipal Buildings	2,086,553	114,495	5.5%
Large Electric	25,237,611	1,326,205	5.3%
Large Electric High Load Factor	94,646,849	4,970,250	5.3%
Master Metered Non-Residential	605,840	30,075	5.0%
High Voltage	5,531,634	385,086	7.0%
Large Interruptible	3,977,229	248,788	6.3%
Lighting Service	4,020,700	266,394	6.6%
Total	$389,845,342	$20,822,231	5.3%

1 This $20.8 million total proposed change in FRP revenue includes the agreed-to outside-the-bandwidth electric revenue of $3.4 million.

Table 3 presents ENO's 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	$24,481,223	$5,312,553	21.7%
Small General	5,245,920	1,138,392	21.7%
Large General	5,498,238	1,193,146	21.7%
Small Municipal	55,584	12,062	21.7%
Large Municipal	2,606,497	565,623	21.7%
Total	$37,887,462	$8,221,776	21.7%

ENO's estimate of electric and gas typical bill impacts from its electric FRP Evaluation Filing (decoupling), ENO Alternative Proposal, and Gas FRP Evaluation Filing revenue changes are presented in Tables 4, 4a, 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	-	$130.03	$137.93	$7.90
Small Electric	9,125	50	$1,345	$1,242	($102.88)
Large Electric	91,250	250	$9,948	$8,870	($1,077.28)

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.). Had ENO instead presented summer typical bills, present bills would have been $132.34, proposed bills would have been $140.41, and the change would have been $8.07.

Table 4a ENO Alternative Proposal Estimated Change to Typical Electric (Legacy) Customer Monthly Bill					
Rate Class	Typical Energy (kWh)	Typical Demand (kW)	Present	Proposed	Change
Residential[1]	1,000	-	$130.03	$133.82	$3.79
Small Electric	9,125	50	$1,345	$1,385	$40.33
Large Electric	91,250	250	$9,948	$10,185	$237.10

1. ENO's presented residential typical bills are calculated using a simple average of summer and winter typical bills. Had ENO instead presented summer typical bills, present bills would have been $132.34, proposed bills would have been $136.21, and the change would have been $3.87.

Table 5 ENO Proposed Estimated Change to Typical Gas Customer Monthly Bill				
Rate Class	Typical Usage	Present	Proposed	Change
Residential	50 ccf	$59.72	$65.57	$5.85
Small General	500 ccf	$472.24	$511.97	$39.73
Large General	1,000 mcf	$8,054	$8,639	$585.11

ENO's 2022 Financial Performance

As part of ENO's discussion of its proposed $17.4 million electric revenue increase, ENO states that its FRP Evaluation Filing "reflects an Earned Rate of Return on Common Equity ("EROE") of 7.34%"[13] which is outside the Council's authorized 8.85% to 9.85% ROE bandwidth range. Of note, ENO's electric EROE value in this statement is based on its *adjusted* cost of service, which includes substantial proforma cost increases for 2023, such as new plant for 2023 that was not in service in 2022.

ENO's final 2022 EFRP revenue requirement was $465,424,129.[14] In the instant Evaluation, ENO reports present revenues of $477,458,223,[15] or $12,034,094 more than ENO's 2022 FRP revenue requirement. As such, ENO's 2022 FRP rate adjustment fully allowed it the reasonable opportunity to earn its allowed ROE of 9.35%. ENO's request for increased FRP rates relates to proposed increases in its cost of service from 2022 to 2023, not to any underperformance in 2022 or the Council's failure to allow ENO appropriate FRP rates.

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 65 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 2023-August 2024);[16]
2) adherence to the EFRP-6 and GFRP-6 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.

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13 FRP Evaluation Filing, *Summary Pleading*, XIV at 12. *See* also FRP Evaluation Filing, Attachment B at 1:19.

14 *See* ENO's 2022 *Final Compliance w Decoupling Attachment A WP*, Applicable Base Revenue ($376,379,526) plus Total EFRP Revenue ($89,045,604).

15 *See* FRP Evaluation Filing, *Compliance w Decoupling AJ01A A GPart 1*, Applicable Base Revenue ($389,845,342) plus EFRP Revenue Annualization Amount ($87,612,881).

16 As we discuss later in this report, the FRP rates set in the instant FRP Evaluation may persist beyond August 2024.

Our review identified several adjustments to ENO's proposed FRP revenues as well as applications of available funds to mitigate bill impacts. Table 6 presents the Advisor Adjustments and mitigation measures. 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 and Mitigation Measures
($ Millions) [1]

Description	*Electric*	*Gas*	*Total Company*
ENO Proposed FRP Revenue Increase	$17.42	$8.18	$25.64
Agreed-to Outside-the-Bandwidth Revenues	$3.40	$0.04	$3.40
ENO Proposed Incremental FRP Revenues	**$20.82**	**$8.22**	**$29.04**
Advisor Adjustments			
ADV02 – OPEB	$2.17	$1.24	$3.41
ADV04 – R&E Accrual	$0.03	-	$0.03
ADV05 – Hurricane Ida Payroll	$0.55	-	$0.55
ADV06 – FIN48 Interest	$0.42	$0.04	$0.46
ADV07 – LCFC	$1.72	-	$1.72
ADV08 – Minor Storms	$1.83	-	$1.83
ADV09 – Storm Proforma	$0.29	-	$0.29
Subtotal – Advisor Adjustments	**$7.02**	**$1.28**	**$8.30**
Total Adjusted FRP Revenue			
Advisor Recommended Bill Mitigation Measures			
ADV10 – Expiring Revenue Requirements	$5.69	-	$5.69
ADV11 – FERC Refund Regulatory Liability	$6.40	-	$6.40
Subtotal – Bill Mitigation	**$12.09**	**-**	**$12.09**
Total Adjusted and Mitigated Revenues	**$1.72**	**$6.94**	**$8.66**

1. 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" (*e.g.*, ADV02 – OPEB). Additionally, for each Advisor Adjustment, the specific adjustment dollar amount by ENO Account is detailed in Attachment C to this report. Of note, each adjustment's enumeration is intended to match that of our 2022 report as applicable. As discussed later in this report, some Advisor Adjustments in the 2022 report do not carry forward into this report, therefore some enumerations are unused.

OPEB Expense (ADV02)

To satisfy its Other Post-Retirement Benefits ("OPEB") obligations to retirees, ENO established an external trust, funded through costs recovered in rates. Each year, in accordance with Generally Accepted Accounting Principles, ENO's external actuary redetermines ENO's OPEB obligation and determines the annual OPEB costs associated with satisfying ENO's OPEB obligation to ENO employees.

ENO has taken steps to reduce ENO's OPEB obligations and OPEB costs to customers; these steps have resulted in the OPEB external trust being fully funded.[17] Barring an unforeseen event, these changes have put ENO on the path to its OPEB obligation being fully funded in the future.

The resulting overfunding has caused ENO's OPEB cost to become a credit to ENO's revenue requirement. In 2012, ENO's net OPEB cost was $4.5 million. In 2021, ENO's net OPEB cost was ($6.4) million. ENO allocates a portion of this amount to OPEB expense, which is recorded to Account 926, and a portion to capital, which is added to plant costs in Account 107. ENO's OPEB expense (credit) amounts by year are presented in Table 7.

Table 7
ENO OPEB Cost by Year
($ in Thousands)[1]

Year	OPEB (Income)/Cost
2022	($6,720)
2021	($6,420)
2020	($4,929)
2019	($3,450)
2018	($3,673)
2017	($2,521)
2016	($2,803)
2015	($1,617)
2014	($1,455)
2013	$2,625
2012	$4,486
2011	$3,669
2010	$5,205

1 Source Entergy Corporation SEC Form 10-K Reports, "Net other postretirement benefit (income)/cost"

17 In 2013, ENO modified the structure of the OPEB plan to lower such costs. Subsequently, ENO eliminated OPEB for all non-bargaining employees hired or rehired after June 30, 2014 and set a dollar limit cap on future increases in the Company's contribution to retiree medical costs effective 2019 for those employees that began receiving their OPEB benefits on or after January 1, 2015. In March 2020, ENO announced additional OPEB plan design changes for retirees that are former non-bargaining employees to reduce costs; these changes take advantage of marketplace innovations and implement a Medicare exchange program to replace the current supplemental medical plan options available.

As the Table 7 shows, OPEB Cost has been declining since at least 2010, and became negative (*i.e.*, a credit or an income source) in 2014, consistent with Entergy's related actions discussed above.

ENO proposes, as it did in its 2022 FRP Evaluation Filing, that the expense portion of the OPEB Credit be excluded from the calculation of Net Utility Operating Income in the FRP Evaluation Filing, as proposed in Adjustment AJ08F, and that ENO be authorized to cease allocating the capital portion of the OPEB Credit to plant costs on a prospective basis. Specifically, ENO proposes, in proforma Adjustment AJ08F – Pension, to reverse (*i.e.*, debit O&M) $2,161,174 electric and $1,244,979 gas in OPEB expense credit (*i.e.*, a negative expense) from operating expense. ENO argues this is appropriate because, although ENO's OPEB cost is negative, ENO does not receive cash or other assets from the OPEB external trust to fund the OPEB Credit.

In the 2018 Rate Case, ENO's per-book equivalent expense was $59,779 (a debit, or positive expense),[18] and ENO made no proforma adjustments to that cost. Prior to the 2018 Rate Case, in ENO's 2012 FRP Evaluation Filing, ENO's Account 926 expense of $11,237,860 similarly was not proformed and was recoverable in rates.[19] Only with negative OPEB costs does ENO propose to remove the credit from its cost of service.

ENO's proposal in the instant FRP Evaluation is not appropriate. First, this is a ratemaking treatment not supported by the Council's precedential finding in the 2018 Rate Case. Second, ENO's revenue requirement is primarily driven by per-book accrual accounting data, of which these OPEB expenses are but one example. ENO often incurs expenses that do not tie to current cash flows. At some point, ENO's negative OPEB expenses will either cause its accounting to match future OPEB benefit payments and its external trust's value or an excess of OPEB external trust funds will be recoverable to ENO's owner through a restructuring or termination of that plan. Third, these negative expenses represent a reversal of positive expenses that have been funded by ratepayers. As such, ENO has erred in its proposed OPEB ratemaking adjustment, and Advisor Adjustment ADV02 reverses this error.

R&E Calculation (ADV04)

In ENO's 2022 FRP evaluation, HSPM file, "AJ03A - ADIT_E_WP_HSPM", ENO applied an irrational and unsupported calculation methodology related to its rate base. In that FRP Evaluation Filing, because ENO's actual 2020 Research and Experimentation ("R&E") costs were not satisfactorily large in ENO's subjective opinion, ENO summed four years' such values, but did not divide by four – ENO divided a four-year total by three simply because one year's value was too small in ENO's subjective opinion. ENO's HSPM explanation to this effect was not satisfactory.[20] Our estimated impact of ENO's error in the 2022 FRP Evaluation and inadequate justification for its error was de minimis. As such, we did not attempt to generate an Advisor

18 ENO's September 21, 2018 Application of Entergy New Orleans, LLC for a Change in Electric and Gas Rates Pursuant to Council Resolutions R-15-194 and R-17-504 and for Related Relief, EX 1 - Operations and Maintenance Expenses_EP2, line 103 – 926NS1: ASC 715 NSC - Emp Pens & Ben.

19 *See* ENO's 2012 FRP Evaluation Filing, 8.1.3.1-8.1.3.3 - Operations and Maintenance Expense, Excel line 139. In this filing, ENO did not subtotal OPEB from Account 926.

20 *See* 2022 FRP Evaluation, DR CNO 5-2 and ENO's HSPM response thereto.

Adjustment to correct ENO's error. However, ENO continues to propagate its incorrect calculation in the instant FRP Evaluation Filing.

ENO should not be allowed to apply unsupportable math, even when their ratepayer impact is minor. As such, we have recalculated this accrual and corrected ENO's error by reducing ENO's rate base balance in ENO Account 190884 by $389,373.

Hurricane Ida Payroll (ADV05)

In ENO's adjustment AJ05B, ENO proposes to defer and recover payroll expenses incurred concurrent with system restoration activities following Hurricane Ida. ENO states that it deferred a total of $673,682 in such expenses which it seeks to recover through the EFRP rates. Of this, $546,997 was incurred in 2021 and $126,688 was incurred in 2022.[21] The entirety of this proposal is inappropriate, although we recommend that only the 2021 payroll be adjusted out of ENO's cost of service.

ENO is allowed to set base rates (as adjusted by FRP rates) to allow it the reasonable opportunity to recover its cost of service. ENO's payroll, as well as payroll allocated to ENO from its affiliates, are part of ENO's cost of service. As such, ENO's base rates in 2021 were properly set according to ENO's payroll in the 2020 test year. The fact that some payroll was expended in furtherance of system restoration does not mean ENO was not allowed recovery of such through rates. ENO now wants to seek double-recovery of these 2021 expenses that have already been allowed recovery, which is inappropriate. In any event, according to the prospective ratemaking principle and the text of Rider EFRP-6, ENO may not seek recovery in 2023 for costs incurred in 2021.

Regarding 2022 payroll in ENO's adjustment, ENO appears to have deferred this expense in its per book accounting. The Council did not authorize this deferral, and there is no justification for ENO's having done so. This deferral is inappropriate, and ENO should refrain from doing so in the future. However, as ENO Adjustment AJ05B essentially seeks to reverse an inappropriate deferral (in the amount of $126,688), we recommend that the Council allow this portion of AJ05B, as ENO's two errors net to a zero impact on ratepayers as compared to a correct ratemaking treatment. ENO should cease deferring regular payroll-related expenses simply because they are recorded with a project code associated with a weather-related event.

Interest on FIN48 Tax Liabilities (ADV06)

In ENO's Adjustment AJ06B, ENO requests recovery of $418,369 (electric) and $39,153 (gas) in calculated interest on tax positions that in ENO's opinion do not meet the "more-likely-than-not recognition threshold"[22] of being allowed by the IRS upon audit (*i.e.*, FIN 48 tax positions).[23] Given the uncertainty of the amount and timing of any interest payment related to FIN 48 tax positions, until such time as ENO makes such an interest payment related to these FIN 48 tax positions in rate base, ENO should not be allowed to include as a proforma adjustment in its FRP Evaluation reports these calculated interest amounts on FIN 48 tax positions. Further, given ENO's Account 190 Accumulated Deferred Income Tax ("ADIT") balances in rate base related to net operating loss carryforward balances, any recovery of interest related to FIN 48 tax positions must consider whether ratepayers have fully enjoyed the benefit of these positions or whether a portion

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

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

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

of the Account 190 balances offset such benefit. We have corrected ENO's error regarding FIN 48 interest by reversing these electric and gas expenses through Advisor Adjustment ADV06.

LCFC and Energy Smart Goals (ADV07)

ENO's proposed EFRP revenue increase includes a $8,589,170 Present Revenue decrease[24] (an increase to ENO's revenue requirement) to account for ENO's expected Lost Contribution to Fixed Costs ("LCFC") related to energy sales reductions caused by the Council's Energy Smart program over the year following the Evaluation Period. This $8.6 million increase to ENO's EFRP revenue requirement was estimated from the 2023 kWh Savings goal approved in Council Resolution No. R-22-523 and the Adjusted Gross Margin representing fixed cost $/kWh. The use of the actual 2022 Energy Smart program kWh reduction compared to the 2022 kWh Savings goal provides a more certain estimate for determining an estimated LCFC adjustment for 2023. ENO did not nearly achieve its Council-approved Energy Smart Program Year 12 savings goal in 2022, achieving 79.88% of goal, and the LCFC ENO experienced in 2022 based on achieved kWh savings was $6.3 million.[25] The EFRP tariff, Attachment H provides for known and measurable adjustments to rate base and operating income, including the LCFC expected to result from Energy Smart. However, Attachment H does not specify that the LCFC estimate be the program year goal from the three-year Energy Smart Implementation Plan; and although not a known and measurable cost, the LCFC proforma adjustment should be supported as much as possible with a reliable current estimate based on current information.[26]

Recent years' experience shows that an LCFC estimate based on ENO's Energy Smart three-year kWh savings goals is not necessarily a reliable estimate for the actual lost contributions to fixed costs that ENO may experience. As such ENO has erred in proposing a $8.6 million LCFC adjustment amount in its EFRP Evaluation Filing. The Advisors adjust this 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 2022 compared to the 2022 kWh savings goal, and applying that factor to the 2023 savings goal to estimate an LCFC adjustment in the Evaluation. After this Advisor Adjustment, ENO's LCFC revenue adjustment should be reduced by $1.7 million. Advisor Adjustment ADV07 effects this correction to ENO's error.

Minor Storm Costs (ADV08)

In the FRP Evaluation Filing, ENO has sought to recover O&M costs related to minor storm costs incurred in 2021 and 2022. As with payroll costs related to Hurricane Ida, discussed above (ADV05), ENO's cost of service includes O&M costs that vary individually from year to year. However, the 2022 Test Year's total O&M costs are generally accepted to be the proper indicator for prospective total O&M costs. ENO, through its adjustment AJ05, seeks to single-out O&M costs related to what it describes as minor storm events. This constitutes inappropriate single-issue-

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24 *See* FRP Evaluation Filing, Adjustment AJ08D.

25 Lost Contribution to Fixed Costs and Utility Performance Incentive Filing for Energy Smart Program Year 12 for Entergy New Orleans, June 30, 2023.

26 In the LCFC discussion in the 2018 general rate case, ENO's proposal advocated LCFC recovery based on actual results. *See* Resolution R-19-457, page 156.

ratemaking, and ENO should cease deferring these O&M costs that it deems as related to minor storm events.

Those costs incurred by ENO in 2021, $816,928,[27] have already been allowed recovery through ENO's base rates (as adjusted through the 2022 FRP Evaluation). These proforma costs are an error on ENO's behalf. Regarding costs incurred by ENO in 2022, $188,481,[28] ENO appears to have deferred these costs in 2022, which is an inappropriate deferral that constitutes single-issue-ratemaking. As such, ENO is essentially reintroducing the same costs it deferred. As such, no adjustment is necessary for 2022 costs as ENO's two errors are offsetting.

Further, ENO seeks to implement a $1 million reserve for future deferred O&M. It is inappropriate for ENO to seek recovery now for unknown and unmeasurable potential future O&M costs. We note that no part of AJ05C indicates a related rate base liability for ENO's proposed reserve.

We correct these errors in Advisor Adjustment ADV08.

Proforma Storm Capital Investments (ADV09)

The FRP riders allow ENO to proform costs into its cost of service related to the year following the test year (i.e., 2023 for the instant FRP Evaluation Filing). Rider Schedule EFRP-6 (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.[29]

ENO has requested a $2,552,588[30] proforma addition to distribution plant in service related to storm restoration capital costs that may be incurred in 2023 with respect to minor weather events. As with ENO's 2022 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.

As such, consistent with our recommendations in our 2022 report, ENO erred in proposing the proforma adjustment to add $2,552,588 to its plant in service. Advisor Adjustment ADV09 corrects this error by removing this proforma and its related ratemaking effects.

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 with a complete supporting

27 *See* ENO's response to DR CNO 1-31.
28 See Id.
29 Rider Schedule EFRP-6, FN 1 at pg. 30.3
30 *See* FRP Evaluation Filing, Attachment H (electric), funding project "F1PCDSTR0N: DISTR STORM DAMAGE CAPITAL, ENOI".

analysis is necessary to maintain fairness in the customer class Decoupling revenue adjustments. Certain methods of cost allocation were addressed in Resolution R-19-457, while the treatment of other cost allocation methods, such as the capacity cost allocation related to interruptible loads, while not specifically addressed, were included within the Council's directives in Resolution R-19-457 related to the allocation of customer class revenue requirements.

Ordering Paragraph 26 of Resolution R-19-457 states that: (i) ENO's decoupling proposal shall be modified such that a full decoupling mechanism shall be filed with each electric EFRP evaluation, with total allocated costs of service for each customer class included in the decoupling revenue adjustment; (ii) the customer rate class allocation factors be updated annually with current billing determinants; and (iii) a new baseline of customer class fixed and variable revenue requirements shall be determined in each EFRP evaluation from an allocation of total operating costs and a return component based on the rates of return corresponding to the customer class total revenues set in the instant docket; and (iv) any adjustments that may be needed to the relative rates of return will be such that those adjustments move the relative customer class rates of return toward the utility's rate of return based on the weighted average cost of capital. Of note, ENO discussed a "Decoupling Pilot Program implemented in Ordering Paragraph 26 of Resolution R-19-457. . ."[31] To be clear, Resolution R-19-457 does not implement a "pilot" program; Ordering Paragraph 26 does not contain the word "pilot", but rather establishes the above requirements for ENO's EFRP Evaluation Filings.

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. Ordering Paragraph 14 of Resolution R-19-457 and Attachment G of Rider Schedule EFRP-6 specify that customer class revenue requirements are determined by Decoupling and provide for no alternative that permits the ENO Alternative Proposal.

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 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 raised several questions when compared to the comparable allocation factors developed in the recent 2018 Rate Case. Specifically, prior to the installation of AMI meters and supporting systems, residential and other small customer classes capacity-related fixed cost allocation factors had to be estimated since no hourly meter data was yet available to provide residential class demands at the required specific hours.[32] That estimation required the use of current load research data, with sampled results of a small group applied statistically to the entire residential customer class. Residential customer class "load characteristics" relating average customer monthly usage to monthly peak hour demands would not be expected to change dramatically for twelve-month periods not far removed from each

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31 FRP Evaluation Filing, Summary Pleading, VII at 8

32 The capability of AMI meters and supporting legacy systems to provide usage at specific hours is addressed below.

other. Residential average monthly usage in the 2018 test period was 1,020 kWh/customer, and in the 2021 EFRP Evaluation (October 2020 -September 2021) the Residential customer class average monthly usage was 1,041 kWh/customer, not very different. Yet, the estimated Residential customer class ratio of average to peak usage (load factor) was notably different between these two periods due to the difference in the estimates of Residential peak demands. In the recent 2018 Rate Case the estimated residential class average to peak demand monthly load factor was 66.92%, compared to the estimated residential class average to peak demand monthly load factor of 50.75% for the 2021 test year and 56.18% for the 2022 Test Year. Clearly, the EFRP test period estimates of Residential coincident peak demands were notably higher relative to the estimated Residential peak demands in the recent rate case, with corresponding impacts on cost allocation.

For an explanation of the difference in these estimates, the Advisors requested that ENO provide the load research data which supports all estimation and derivations of demands used for cost allocation not directly related to metered data for the 2018 test period, as well as for the EFRP Evaluation, 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 for both 12-month test periods, including references and data supporting any differences.[33] ENO did confirm that there had been no change to the methodology to produce the underlying demand data.[34] The Advisors also requested that ENO provide a worksheet comparing the customer class monthly peak load factors for the two twelve-month periods requested, as well as references and data supporting any differences,[35] to which ENO replied that the two sets of load-based allocation factors are not sufficiently comparable for the Company to provide any variance explanations.[36] To emphasize that the Advisors' request was limited to the specific load research data results that supported the allocation factors, the Advisors requested that ENO provide the requested load research data and the worksheet applying such data to estimate demands in both periods, including references and data supporting any differences.[37] ENO responded that the Company does not have worksheets applying raw load research data to estimate demands used in the 2018 Rate Case and the twelve months ended September 30, 2021 because such analysis occurs within the load research analytics system.[38]

Since ENO could not provide any worksheets previously to support the capacity-related fixed cost allocation factors between the recent rate case and the 2022 FRP Evaluation,[39] the Advisors issued discovery requesting the source documents and complete workpapers supporting the estimates of monthly peak demands for each of the capacity cost allocation factors.[40] ENO provided workpapers summarizing the load research sample data used to estimate the monthly peak demands in the 2022 Test Year. Since the peak demand monthly load factors continue to show variation over the test periods since the rate case, and load research sample data is used to estimate the peak demands, the Advisors considered that a more representative allocation of capacity costs would be achieved by constructing an alternative for this Evaluation consistent with the approach that the Advisors used in the 2022 EFRP. The capacity-related fixed cost allocation factors were

33 DR CNO 3-12 in the 2022 EFRP. ENO did not respond to the DR but stated that the two sets of allocation factors are not sufficiently comparable for the Company to provide any variance explanations. "Moreover, the Company cannot prepare comparable test year 2021 allocation factors for this proceeding."

34 ENO's response to DR CNO 3-13 in the 2022 EFRP

35 ENO's response to DR CNO 4-11 and CNO 4-12 in the 2022 EFRP.

36 *Id*

37 ENO's response to DR CNO 4-13 and CNO 4-14 in the 2022 EFRP.

38 *Id*

39 *Id*

40 Response to CNO 3-5.

developed from available ENO data for the following five recent twelve-month periods: period ended December 31, 2018; period ended September 30, 2019; period ended September 30, 2020; period ended September 30, 2021; and period ended September 30, 2022. The kW coincident peak demands for the five 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. 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 the rate case, (ii) the variability of the demand estimates since the rate case, 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.[41]

The Advisors' Decoupling analysis also noted a discrepancy 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, the total allocated cost of service is credited with operating revenue by customer class from the Purchased Power Cost Recovery ("PPCR") Rider, all other Riders, and other non-tariff operating revenue. The PPCR Rider was used to apply mitigation revenue credits related to the 2022 EFRP final revenue adjustment. Mitigation credits applied through the PPCR Rider should not be used as an offset in determing PPCR revenue associated with recovering PPCR costs by rate class. Instead of applying the customer class PPCR Rider Tariff revenue directly associated with PPCR cost recovery as a credit to the allocated cost of service, ENO allocated the PPCR Rider revenue credit using an allocator which included mitigation revenue credits not associated with the recovery of purchased power costs.[42] To address this customer class revenue requirements discrepancy with a more supportable basis for the PPCR revenue credit, the Advisors referenced the PPCR costs in the 2022 monthly PPCR filing workpapers to identify PPCR revenue requirements by customer class in which revenue mitigation was not included. This correction to the PPCR revenue credit by customer class impacted the present rates of return as well as the EFRP revenue adjustment by customer class.

The comparative results of electric rate class revenue and corresponding rates of return are presented herein in the following Attachments: (i) for the 2018 rate case, in Attachment A, page 1; (ii) for ENO's proposed decoupling compliance, in Attachment A, page 2; (iii) for the Advisors' proposed decoupling, in Attachment B. In developing the proposed Decoupling adjustment by rate

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41 For 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."

42 Response to CNO 5-2 and CNO 6-2.

class, the Advisors considered both changes to the test period present rates of return (prior to the EFRP adjustment)[43] as well as changes to present customer class revenues.

ENO's EFRP Evaluation was consistent with respect to applying the structure of Advisors' Exhibit VP-20 from Council Docket No. UD-18-07 in proposing the allocated customer class revenue requirements related to the EFRP Decoupling adjustment. However, ENO's FRP Evaluation Filing presented Decoupling with few changes in customer class rates of return relative to those applied in the 2022 EFRP revenue requirement adjustment. In contrast, as seen in comparing Attachment A, page 2 and Attachment B, the Advisors' application of Decoupling results in more equitable EFRP percent revenue changes among the customer classes, as well as adjustments to customer class rates of return.

As noted previously, Ordering Paragraph 26 of Resolution R-19-457 stated that any adjustments that may be needed to the relative rates of return will be such that those adjustments move the relative customer class rates of return toward the utility's rate of return based on the weighted average cost of capital.[44] Compared to the present test period customer class rates of return prior to this EFRP revenue adjustment, the Advisors' proposed decoupling increased low customer class rates of return consistent with reasonable revenue adjustments.

Resolution R-19-457 also directed that rate classes Master Metered Non-Residential, Large Electric High Voltage and Large Interruptible Service, shall have a decoupling revenue adjustment cap of 10% which will apply to each of the 3 annual EFRP evaluation period revenue adjustments provided that the total electric utility FRP revenue adjustment for that evaluation does not exceed 10%. With the Advisors' proposed change in total EFRP revenue, (see Table 2) that decoupling revenue adjustment cap is applicable to the instant EFRP Evaluation but was not exceeded for those three customer classes.

Bill Mitigation Adjustments

Expiring Revenue Requirements (ADV10)

ENO's base rate revenue requirement includes the amortization of certain regulatory assets and a return on those assets' unamortized balance at ENO's WACC (unless a different return was negotiated). If a regulatory asset were to be fully amortized during a period when ENO's rates are not reset (*i.e.*, when there is no annual FRP evaluation or rate case), rates would continue to reflect the amortization of the regulatory asset even when no corresponding expense remains. In this scenario, ratepayers would receive no benefit commensurate with this portion of their payments to ENO.

Similarly, the EFRP Evaluation includes $3,399,091 in agreed to outside-the-bandwidth revenues. After August 2024, ENO no longer has this revenue requirement, but as with expiring regulatory assets, without a rate adjustment effective September 2024, ENO's rates will allow it to collect this amount that it will no longer require.

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[43] ENO's presentation of present customer class rates of return on allocated rate base, prior to the EFRP rate adjustment, is included in Supplemental Workpapers, Compliance w Decoupling AJ01A A G Part 2, RR1, line 8.

[44] ENO proposed an alternative set of revenue adjustments that did not incorporate decoupling, as discussed herein. The alternative proposal essentially applied the total EFRP revenue adjustment on rate class base revenues with no consideration of changes to rate class rates of return.

Relative to this concern, we asked ENO if it intended to seek a rate change (*e.g.*, a FRP extension or a new rate case) effective at the end of the instant FRP Evaluation's rate effective period (*i.e.*, effective September 2024). Such a rate change would address the concern of expiring regulatory assets and the outside-the-bandwidth revenue amount. ENO refused to provide an answer.[45] As such, we consider it prudent to plan as if ENO will not undergo a rate review setting new rates as of September 2024 and that its base rates (including FRP rates) will remain fixed at the rates the Council will set in the instant FRP Evaluation for at least a few months past this date.

To prevent ENO's rates from allowing collection of an expired cost (*i.e.*, costs associated with expired regulatory assets or the allowed outside-the-bandwidth revenues), we recommend that the Council direct ENO to retire certain regulatory assets (*i.e.*, those expiring in 2024 through 2026), as well as the outside-the-bandwidth revenues, effective August 31, 2023, using ratepayer credits available for use at the Council's direction. The regulatory assets and revenue requirements we identified are,

- The Agreed-to Outside-the-Bandwidth Revenues
- The Union PB1 Outage Regulatory Asset
- The Algiers Migration Regulatory Asset
- The IRIS Solar Facility PPA Regulatory Asset

This retirement of these identified regulatory assets and revenues is affected through Advisor Adjustment ADV10. We calculate that this adjustment requires the use of $8,590,263 in ratepayer credits, which would not require the use of the $34,838,880 in ratepayer credits related to FERC Docket No. EL18-152, which as we discuss earlier in this report, is potentially subject to claw-back if Entergy's appeal of this proceeding's order is successful.

Even should there be a FRP extension (the only practicable means of adjusting rates effective September 2024), to which ENO has not indicated it would agree, our recommended Council actions in this letter would continue to offer ratepayer benefits. First, the regulatory principle of rate stability would be supported because our recommended Council actions provide relatively stable ratepayer relief over several years as opposed to short-term credits. Second, our recommended Council actions provide ENO useful long-term capital whose carrying costs are a credit to ratepayers. As such, our recommended Council actions benefit both ENO and ratepayers.

Effecting Advisor Adjustment ADV10 requires the Council to direct ENO to take appropriate action (*i.e.*, retire the regulatory assets using available ratepayer credits) prior to ENO's final calculation of new Rider EFRP rates for the September 2023 billing cycles. Based on our general understanding of ENO's billing processes, such Council direction would likely need to be provided by the second week in August.

<u>Alternate Recommendations</u>

Should the Council decline to implement the adjustment we recommend (ADV10), we offer the following alternatives.

1. The Council may direct ENO to make a rate case filing with rates effective on or about September 1, 2024. This option is potentially unfeasible because ENO may not administratively be able to prepare such a filing by August 2023, which would allow new

[45] *See* ENO's objection to DR CNO 1-25.

rates to be set effective September 2024 based on the statutory 12-month procedural schedule of a rate case.

2. The Council may seek a FRP extension. This option requires ENO's cooperation, as it is our general understanding that a FRP extension cannot be imposed on ENO as it would require ENO to accept its present allowed ROE. Still, given ENO's stated spending plans for 2024 and beyond, a FRP extension is likely in ENO's interest compared to leaving rates fixed, even with the expiration of substantial regulatory assets and the expiration of the outside-the-bandwidth revenues.
3. The Council may direct ENO to realign the revenue requirements associated with these regulatory assets and outside-the-bandwidth revenues to Rider PPCR. Such a realignment would allow these revenues to expire as part of Rider PPCR's monthly rate calculation.

Use of Ratepayer Credits (ADV11)

As discussed earlier in this report, Entergy is seeking to overturn the credits provided to ENO related to FERC Docket No. EL18-152 ($34,838,880). We have not sought to evaluate Entergy's likelihood of success, but out of an abundance of caution in the event Entergy might succeed, we recommend against immediately returning these funds to ratepayers, as they may have to return these funds to ENO in the event Entergy later prevails in its appeal. Instead, we recommend establishing a regulatory liability as of August 30, 2023 with these funds. While such retirements will not provide ratepayers as great of an initial rate relief as would one-time bill credits, returning these funds to ratepayers over time, while allowing ratepayers a return on the regulatory liability, reduces ratepayer risk from any funds that are clawed-back as a result of Entergy's appeal.

As such, we recommend that the Council direct ENO to create a regulatory liability in the amount of $34,838,880, properly reflect this regulatory liability in rate base, and amortize this regulatory liability on a 10-year straight-line basis. In the event Entergy prevails in its appeal of the FERC docket order underlying this $34,838,880 credit, the Council may then cease amortization of the regulatory liability and consider means of recovery of any amounts ENO may owe SERI as a result of the appeal.

We have prepared Advisor Adjustment ADV11 to reflect this recommended regulatory liability and its ratemaking treatment.

As with Advisor Adjustment ADV10, effecting Advisor Adjustment ADV11 requires the Council to direct ENO to take appropriate action (*i.e.*, establish the regulatory liability using the ratepayer credit related to FERC Docket No. EL18-152) prior to ENO's final calculation of new Rider EFRP rates for the September 2023 billing cycles. Based on our general understanding of ENO's billing processes, such Council direction would likely need to be provided by the second week in August.

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 2a, which presents ENO's proposed change in FRP revenue is reproduced for comparison.

Table 2a (reproduced from above) ENO Alternative Proposal Change in Electric FRP Revenues			
Rate Class	Applicable Base Revenue	Proposed Change in FRP Revenue[1]	Proposed Change in FRP Revenue as Percent of Base Revenue
Residential	$182,062,241	$9,944,743	5.5%
Small Electric Service	71,676,686	3,536,196	4.9%
Municipal Buildings	2,086,553	114,495	5.5%
Large Electric	25,237,611	1,326,205	5.3%
Large Electric High Load Factor	94,646,849	4,970,250	5.3%
Master Metered Non-Residential	605,840	30,075	5.0%
High Voltage	5,531,634	385,086	7.0%
Large Interruptible	3,977,229	248,788	6.3%
Lighting Service	4,020,700	266,394	6.6%
Total	$389,845,342	$20,822,231	5.3%
1 This $20.8 million total proposed change in FRP revenue includes the agreed-to outside-the-bandwidth electric revenue of $3.4 million.			

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	$182,062,241	$998,837	0.5%
Small Electric Service	71,676,686	122,933	0.2%
Municipal Buildings	2,086,553	25,587	1.2%
Large Electric	25,237,611	128,820	0.5%
Large Electric High Load Factor	94,646,849	219,265	0.2%
Master Metered Non-Residential	605,840	(14,349)	-2.4%
High Voltage	5,531,634	67,208	1.2%
Large Interruptible	3,977,229	161,166	4.1%
Lighting Service	4,020,700	12,663	0.3%
Total	$389,845,342	$1,722,130	0.4%

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	$24,481,223	$5,312,553	21.7%
Small General	5,245,920	1,138,392	21.7%
Large General	5,498,238	1,193,146	21.7%
Small Municipal	55,584	12,062	21.7%
Large Municipal	2,606,497	565,623	21.7%
Total	$37,887,462	$8,221,776	21.7%

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	$24,481,223	$4,482,802.65	18.3%
Small General	5,245,920	960,590.21	18.3%
Large General	5,498,238	1,006,792.62	18.3%
Small Municipal	55,584	10,178.12	18.3%
Large Municipal	2,606,497	477,280.59	18.3%
Total	$37,887,462	$6,937,644	18.3%

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 Alternative Proposal	After Advisor Adjustments and Bill Mitigation Measures	Change from ENO Alternative Proposal
Residential	1,000	$130.03	$133.82	$129.78	($4.04)
Small Electric	9,125	$1,345	$1,385	$1,340	($45)
Large Electric	91,250	$9,948	$10,185	$9,874	($311)

As the data in Table 10 indicate, the estimated typical residential bill increase from present rates to those after Advisor Adjustments and the application of bill mitigation funds results in lower typical bills compared to ENO's alternative proposal. Also, as discussed earlier in this report, because ENO has $4.7 million in outside-the-bandwidth revenues from the 2022 FRP Evaluation that are expiring after August 2023, the Advisors recommended rates also result in a small decrease compared to present rates.

The change in typical bills for customers in Algiers is the same as for Legacy customers, except that the electric franchise fee rate in Algiers is 2%, compared to 5% for the rest of New Orleans. As such, Algiers electric typical bill effects are somewhat less after franchise fees are included. All of New Orleans has the same gas franchise fee rate, so gas typical bill effects are the same for all ENO customers.

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	$59.72	$65.57	$64.65	($0.92)
Small General	500 ccf	$472.24	$511.97	$505.76	($6.21)
Large General	1,000 mcf	$8,054	$8,639	$8,548	($91)

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.

Incident Response Department (AJ05D, AJ06C)

ENO has established an Incident Response Department,[46] which according to HSPM documents provided through discovery,[47] seeks to plan for responses to incidents such as severe weather. The focus of employees within the Incident Response Department is specifically on storm response in the wake of the 2020 hurricane season. Our review of ENO documents does not indicate that this department and its function constitute other than a prudent expenditure by ENO. ENO does not explain, however, why it defers this department's expenses ($559,597) only to then ask the Council to allow the same expense to be proformed back into the FRP's rates.[48] Likewise the rate base effect of this deferral is reversed and yields no apparent net effect.[49] These deferrals and related

46 Project Code F3PPSTRMPL, Future Storm Planning
47 *See* ENO's response to DR CNO 5-2
48 *See* ENO proforma AJ05D.
49 *See* ENO proforma AJ06C.

proformas serve no useful purpose that we can identify and have no effect on rates that we can identify from evaluating the FRP Evaluation Filing. ENO should stop deferring these costs and needlessly complicating its filings.

True-Up of Outside-the-Bandwidth-Formula Recoveries

In the 2022 FRP evaluation, we noted that ENO was not allowed the reasonable opportunity to collect its allowed outside-the-bandwidth amounts from the 2021 FRP evaluation because that FRP evaluation's rate effective period was only ten months long. As such, we recommend ENO be allowed recovery, outside the bandwidth, of these revenue amounts of $899,091 and $41,061 for electric and gas respectively. Our review indicates that ENO has properly included these amounts in the instant FRP Evaluation's outside the bandwidth revenue, and we do not recommend any correction to these amounts. However, as discussed earlier in this report, because ENO will not say whether it intends to seek new or adjusted rates in 2024, we recommend that the electric revenue requirement be satisfied as of August 31, 2023 using available credit balances (there are no such available gas ratepayer credits).

AMI Meter Reading Expense

In ENO's 2021 FRP Evaluation Filing, ENO proposed to include in its development of the FRP Rate Adjustments approximately $0.2 million and $0.9 million for electric and gas respectively in Meter Reading Expense (FERC Account 902). We found that ENO had erred in its proposed proforma adjustment by including the 2021 investments required to complete the AMI deployment but not reflecting that deployment's expected operating efficiencies in rates. In the 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, ENO no longer proforms its per book meter reading expense and now states that this expense level reflects expected ongoing such expenses. 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."[50] However, ENO now wants recover of approximately $1.1 million in meter reading expenses. ENO is unable to say how much of this expense is to recover the on-site (versus "remote") meter reading activity that ENO claimed would be eliminated.[51] ENO claims that this direct quote from its AMI application is out of context,[52] but the quote is complete and ENO's newly-introduced meter reading expense is substantial relative to its promised administrative savings. ENO witness Jay A. Lewis estimated 2022 ratepayer savings in avoided contract meter reading costs of $2.5 million.[53] ENO does not claim that its forecast of ratepayer savings in Docket No. UD-16-04 lacks context. ENO's meter reading expense that it seeks to recover represents over 40% of the costs ENO stated would be avoided. In other words, ENO has fallen roughly 40% short of its forecasted ratepayer

50 Council Docket No. UD-16-04, Direct Testimony of Dennis P. Dawsey at 11
51 *See* ENO's response to DR CNO 4-2.
52 See *Id.*
53 Council Docket No. UD-16-04, HSPM Exhibit JAL-2.

savings related to meter reading (ENO cannot determine how much of its 2022 meter reading expense is for on-site meter reading, so this ratio cannot be calculated with precision).

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 the Council direct ENO to prepare and file a report explaining why its AMI deployment failed to generate its forecasted ratepayer savings.

NJ Customer Cost of Service Required but not Performed.

In DR CNO 2-12 of the 2022 FRP, ENO was asked why there was no NJ cost of service analysis included in the GFRP Evaluation Filing as required by Ordering Paragraph 16 of Resolution R-19-457.[54] ENO's response was unacceptable. The directive to provide a complete NJ cost of service analysis "…as part of future Council rate actions" was clearly stated. Instead, ENO referenced a whereas paragraph that the NJ Study was to accompany the 2020 GFRP Filing, presuming that the term "future rate actions" of the directive should apply only to the 2020 GFRP. Considering the significant increases to gas rates, particularly the impact on residential customers, it is important that the costs of gas service should be shared equitably among <u>all</u> gas customers. ENO should comply with the Council's directive to perform an allocated gas cost of service study as part of all future rate actions which includes all costs and revenues of NJ customers.

Using AMI Capability to Develop Cost Allocation Factors

Considering the lack of support ENO provided for a rigorous analysis of capacity-related allocation factors compared to the rate case allocation, as discussed above, the Advisors asked ENO why (assuming AMI plant and software system are functioning as intended) AMI could not be used in developing and confirming demand-related cost allocation factors, when one or more rate classes' contribution to the monthly peak loads cannot be calculated from meter data.[55] ENO was unresponsive to that DR, 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 ENO responded that upgraded systems and/or increases in resources may be required.[56] 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. More technical discussions with ENO are required to

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[54] Resolution R-19-457, Ordering Paragraph 16, states, "ENO is directed to provide a complete cost of service analysis in support of the NJ customers' rates as part of future Council rate actions."

[55] *See* DR CNO 3-9 in the 2022 EFRP, and ENO's response thereto.

[56] 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."

clarify this issue prior to the electric and gas cost of service analyses developed for ENO's next rate action.

Gas Bill Mitigation

Following hurricanes Katrina and Rita, as part of ENO's gas infrastructure rebuild program (the predecessor to ENO's present Gas Infrastructure Replacement Program ("GIRP")), ENO had replaced approximately 355 miles of gas distribution pipe at a cost of $165.3 million. The rebuild program was funded primarily from insurance proceeds and, accordingly, ENO did not seek recovery of related costs. Once the insurance funds were exhausted, ENO's then-recommended proposal was to replace an additional 238 miles of pipe at an estimated cost of $119.3 million over the nine-to-ten subsequent years.[57]

ENO's scope and cost of GIRP has changed since its initial proposal, with increases in costs, including a $20 million Utility Conflict Survey, and decreases in the number of miles of pipe to be installed. ENO's most currently provided GIRP schedule provides for only 150 miles of new GIRP pipe, compared to the original proposal of 238 miles.[58]

The Advisors have on multiple occasions expressed concern regarding the bill impact related to ENO's present GIRP investments. While the Advisors have stated that replacement of older, less reliable, pipe materials is consistent with industry practice, the pace of GIRP has imposed a heavy ratepayer burden.

ENO stated that its existing GIRP replacement schedule through 2022 would include the vast majority of the legacy utilization-pressure system, which is a major objective of GIRP.[59] As such, ENO proposed modifying its existing GIRP program timeline starting with 2023.[60] Our review of the instant FRP Evaluation Filing indicates that ENO has substantially slowed-down the rate of its GIRP investments. ENO's proposed gas rate base is $4.1 million less than in its prior-year FRP Evaluation Filing;[61] a substantial cause of this decrease is ENO's 2023 plant investments being less than its 2023 depreciation expenses.[62]

Despite the slowing of gas plant investment, GFRP rates remain sufficiently elevated (*i.e.*, ENO proposes a GFRP rate of 65.8752%[63]) to warrant concern for the affordability of gas utility service in New Orleans. As such, we continue to recommend that ENO agree-to, and the Council approve, mitigation through a change in an ENO gas depreciation rate.

ENO's Gas Infrastructure Replacement Project primarily employs High Density Polyethylene ("HDPE") pipe, which ENO refers to as "plastic".[64] ENO presently applies a 3.33% depreciation rate, which reflects a roughly 30-year depreciable life for this plant. We note that the Council originally directed ENO to employ a 40-year depreciation schedule for GIRP investments.[65] A 30-

57 *See* New Orleans Gas System Infrastructure Replacement Update, October 27, 2016, slide 9.
58 *See* GIRP Working Group – Gas Ops – v5 draft, February 19, 2020, slide 4.
59 *See* 2021 FRP Evaluation, ENO's response to DR CNO 2-8.
60 See *Id.*
61 *See* gas Attachment B, line 1, which presents a rate base of $200,033,762 in the instant FRP Evaluation Filing and $204,163,243 in the 2022 FRP Evaluation Filing.
62 *See* AJ08A - Plant Transfers_G, line 74, which shows a net proforma adjustment reducing rate base by $2.1 million.
63 *See* GFRP Evaluation, Attachment A (gas).
64 ENO Account 376.3 Mains-Plastic
65 *See* Council Resolution No. R-17-38, Ordering Paragraph 2.

year depreciation schedule for GIRP investments is outside the industry range. ENO should return to a 40-year depreciation schedule (specifically a 2.34% depreciation rate) commencing September 1, 2023 (when new rates under the FRP become effective).

Further, we note that a 40-year depreciation schedule for HDPE pipe as was employed by ENO prior to the 2018 Rate Case, while more nearly appropriate than the present 30-year schedule, remains likely unreasonably brief. A 2019 depreciation study by Gannett Fleming, Inc. on behalf of Vermont Gas Systems Inc. recommended a 55-year schedule: "The 55-year average life is within the range of lives used by others in the industry. Most other gas companies estimate lives between 55 and 70 years."[66] As such, while the Council had directed a 40-year depreciation schedule for GIRP, and a return to this rate is recommended effective September 1, 2023, there exists evidence that an even longer, up-to 70-year, depreciation schedule is appropriate. Given the ratepayer burden resulting from ENO's GIRP investments, we recommend that the Council consider a longer depreciation life consistent with industry practice for plastic distribution main plant in the rate action involving a gas depreciation study (*i.e.*, the next retail rate case).

Non-Typical Test Year

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. This electric revenue impact was $11.3 million. Based on the text of Rider EFRP as well as the regulatory principle of prospective ratemaking, we adjusted ENO's 2022 EFRP Present Revenues by $11,254,182 (which represented a decrease to ENO's FRP revenue requirement). As we note earlier in this report, ENO did collect revenues in excess of the revenue requirement we calculated (and which was implemented in ENO's FRP rates). In our view, it is demonstrated that this adjustment in the 2022 FRP evaluation was properly calculated to allow ENO the reasonable opportunity to earn the Council-allowed ROE of 9.35% for that FRP's rate effective period (*i.e.*, September 2022-August 2023).

We are aware of 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 2022 Test Year revenues, we do not recommend any adjustments to ENO's Present Revenues in this area.

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66 Gannett Fleming, Inc. *2019 Depreciation Study*, page III-4.

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

ATTACHMENT A
2023 FRP EVALUATION FILING - ENO DECOUPLING FILING
ENTERGY NEW ORLEANS, LLC - ELECTRIC
RATE CLASS RIDER EFRP REVENUE REDETERMINATION

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	1,209,848,389	682,293,842	168,541,513	11,515,436	67,349,693	250,439,119	1,493,465	9,668,189	7,580,122	10,967,011
2	ENO Required Rate of Return on Rate Base After taxes	6.86%									
3	ENO Required Rate of Return on Rate Base Including taxes	8.62%	3.71%	18.13%	19.81%	10.65%	13.67%	18.82%	13.83%	12.28%	19.96%
4	Return on Rate Base including income taxes	104,316,758	25,335,454	30,548,396	2,281,082	7,171,524	34,242,780	281,047	1,336,783	930,954	2,188,738
5	Operation & Maintenance Expense	598,236,932	299,604,395	84,406,395	2,517,278	37,194,574	147,511,193	840,971	11,860,679	10,855,179	3,446,267
6	Gains from Disp of Allowances	-	-	-	-	-	-	-	-	-	-
7	Regulatory Debits & Credits	7,076,725	3,915,802	998,480	57,514	401,175	1,503,279	9,006	72,029	62,860	56,580
8	Interest on Customer Deposits	1,676,662	945,553	233,572	15,959	93,336	347,070	2,070	13,399	10,505	15,199
9	Other Credit Fees	499,634	281,769	69,603	4,756	27,814	103,425	617	3,993	3,130	4,529
10	Depreciation & Amortization Expense	70,130,129	40,477,575	9,822,192	636,717	3,730,686	13,768,820	79,716	531,463	416,984	665,975
11	Amortization of Plant Acquisition Adjustment	1,190,642	625,364	166,621	3,600	73,062	280,749	1,730	22,086	14,937	2,493
12	Taxes Other than Income	19,310,268	11,090,677	2,729,635	162,909	1,025,309	3,824,168	22,970	162,413	129,030	163,157
13	Adjustment (Bad Debt, Reg. Exp. & Tax Difference)	(2,123,603)	(856,962)	(453,080)	(23,956)	(158,004)	(561,891)	507	(23,204)	(15,803)	(31,211)
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	(132,211,324)	(56,866,803)	(19,361,211)	(589,808)	(9,313,577)	(38,014,498)	(202,894)	(3,311,679)	(3,476,177)	(1,074,675)
19	**Total Cost of Service**	**668,102,823**	**324,552,822**	**109,160,603**	**5,066,050**	**40,245,900**	**163,005,094**	**1,035,739**	**10,667,963**	**8,931,600**	**5,437,051**
20	Less Present Revenue [1]	650,679,683	307,794,538	117,382,483	3,174,988	44,352,839	153,827,250	363,657	10,829,874	7,322,491	5,631,564
21	**= Revenue Deficiency (Excess)**	**17,423,140**	**16,758,285**	**(8,221,880)**	**1,891,062**	**(4,106,939)**	**9,177,844**	**672,083**	**(161,911)**	**1,609,109**	**(194,513)**
22	Percent Increase on Total Revenues (MMNR, HV, LIS subject to cap)	2.7%	5.4%	-7.0%	59.6%	-9.3%	6.0%	184.8%	-1.5%	22.0%	-3.5%

	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	(38,065,401)	1,171,782,988	663,921,981	166,901,132	5,944,870	71,698,800	233,058,565	563,880	9,915,304	7,899,833	11,878,622
ENO Required Rate Of Return On Rate Base Including Taxes	8.62%	8.62%	2.96%	21.20%	10.94%	11.10%	14.33%	39.00%	14.38%	2.20%	18.40%
Return On Rate Base Including Income Taxes	(3,282,113)	101,034,645	19,640,180	35,383,040	650,369	7,958,567	33,397,292	219,913	1,425,821	173,796	2,185,666
Operation & Maintenance Expense	(6,266,243)	591,970,689	294,724,768	84,695,130	2,607,682	38,415,517	144,380,466	620,017	11,937,486	10,944,973	3,644,651
Gains From Disposition Of Allowances	0										
Regulatory Debits & Credits	(3,853,688)	3,223,037	1,926,274	467,433	21,934	179,593	582,855	1,791	3,900	(11,323)	50,580
Interest on Customer Deposits	0	1,676,662	945,553	233,572	15,959	93,336	347,070	2,070	13,399	10,505	15,199
Other Credit Fees	(418,639)	80,995	45,891	11,533	414	4,951	16,116	40	685	545	821
Depreciation & Amortization Expense	(75,656)	70,054,474	40,590,309	9,987,607	402,765	4,016,439	13,304,416	39,203	545,762	433,795	734,177
Amortization of Plant Acquisition Adjustment	0	1,190,642	619,013	171,714	5,267	79,720	273,005	799	22,707	15,509	2,908
Taxes Other than Income	(370)	19,309,898	11,109,467	2,775,542	107,879	1,105,129	3,715,267	12,294	166,696	133,816	183,807
Adjustment (Bad Debt, Reg. Exp. & Tax Difference)	(75,911)	(2,199,514)	(887,595)	(469,276)	(24,812)	(163,652)	(581,977)	525	(24,033)	(16,368)	(32,327)
	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)											
EECR (Recovered w/ A Rider)	0	0	0	0	0	0	0	0	0	0	0
Less Credit To COS From Other Operating Revenue:	0	(132,211,324)	(56,866,803)	(19,361,211)	(589,808)	(9,313,577)	(38,014,498)	(202,894)	(3,311,679)	(3,476,177)	(1,074,675)
Total Cost Of Service	(13,972,619)	654,130,204	311,847,057	113,895,084	3,197,649	42,376,024	157,420,012	693,758	10,780,742	8,209,072	5,710,807
EAC Revenues		*22*	*0*	*3*	*1*	*5*	*13*	*0*	-	-	-
FAC Revenues		*147,159,706*	*61,696,222*	*21,960,575*	*550,671*	*10,689,953*	*42,858,248*	*249,073*	*4,028,764*	*3,993,025*	*1,133,174*
FRP Revenue		*87,612,881*	*44,592,505*	*18,770,762*	*412,315*	*5,513,661*	*17,010,500*	*(141,751)*	*914,490*	*(5,322)*	*545,722*
LCFC Revenue	1,728,391	*(6,860,779)*	*(3,365,095)*	*(1,205,648)*	*(36,269)*	*(424,412)*	*(1,591,644)*	*(10,188)*	*(93,024)*	*(66,884)*	*(67,615)*
MISO Revenues		*2,875,162*	*1,578,120*	*410,377*	*11,526*	*173,568*	*584,702*	*3,590*	*51,410*	*55,287*	*6,583*
Purchase Power Revenues		*13,645,905*	*6,241,610*	*2,142,384*	*77,061*	*1,056,818*	*3,692,078*	*1,542*	*280,260*	*94,571*	*59,580*
Sales Revenue	-	*407,975,177*	*200,104,858*	*71,693,699*	*2,156,758*	*25,237,611*	*94,646,849*	*605,840*	*5,531,634*	*3,977,229*	*4,020,700*
Less Present Revenue	1,728,391	652,408,074	310,848,220	113,772,152	3,172,062	42,247,204	157,200,747	708,106	10,713,534	8,047,906	5,698,144
FRP Revenue Change	**(15,701,010)**	**1,722,130**	**998,837**	**122,933**	**25,587**	**128,820**	**219,265**	**(14,349)**	**67,208**	**161,166**	**12,663**

Attachment C
Advisor Adjustments to ENO's
Proposed Ratemaking Treatment by Account

ENO Account(s)	Electric Adjustment DR/(CR)	Gas Adjustment DR/(CR)
ADV02 – OPEB Expense		
OMAG926: 926 PENSIONS & BENEFITS (LOMTOA) ASC 715 926NS1: ASC 715 NSC - Emp Pens & Ben	($2,161,174)	($1,244,979)
ADV04 – R&E Credit Accrual		
190884 - Tax Cr C/F-TAP-Fed	($389,373)	
ADV05 – Hurricane Ida Payroll		
OMP553: 553 MAINT - GENERATION & ELEC EQUIP	($50,827)	
OMD593: 593 MAINT OF OVERHEAD LINES	($45,626)	
OMD598: 598 MAINT OF MISC DISTRIBUTION PLT	($386,686)	
OMAG920: 920 SALARIES	($63858)	
ADV06 – FIN48 Interest		
OCFBL: BANK LOANS & FIN48 - INTEREST EXP COSOCF: Other Credit Fees & FIN48 Int	($418,639)	($39,153)
ADV07 – LCFC		
RSRRLCF: 440-445 SALES–RETAIL - LCFC REVLCF: LCFC Revenue	$1,728,391	
ADV08 – Minor Storms		
OMT571: 571 MAINT OF OVERHEAD LINES	($22,579)	
OMD593: 593 MAINT OF OVERHEAD LINES	($768,936)	
OMAG935: 935 MNTNCE OF GENERAL PLT	($25,413)	
OMAG924: 924 PROPERTY INSURANCE	($1,000,000)	
ADV09 – Storm Proforma Costs		
PLD361: 361 STRUCTURES & IMPROVEMENTS (DS-DD-TO) 1010AM: Electric Plant In Service	($15,965)	
PLD362: 362 STATION EQUIPMENT (DS-DD-TO) 1010AM: Electric Plant In Service	($439,495)	
PLD364: 364 POLES, TOWERS, & FIXTURES (D2-DD-TO) 1010AM: Electric Plant In Service	($400,898)	
PLD365: 365 OVERHEAD CONDUCTORS & DEVICES (D2-DD-TO) 1010AM: Electric Plant In Service	($650,671)	
PLD368: 368 LINE TRANSFORMERS (DX-DD-TO) 1010AM: Electric Plant In Service	($740,430)	
PLD3691: 369.1 OVERHEAD SERVICES (DV-CC-TO) 1010AM: Electric Plant In Service	($230,322)	
DXD361: 361 STRUCTURES & IMPROVEMENTS (DS-DD-TO) 4030AM: Depreciation Expense	($160)	
DXD362: 362 STATION EQUIPMENT (DS-DD-TO) 4030AM: Depreciation Expense	($4,976)	

Attachment C
Advisor Adjustments to ENO's
Proposed Ratemaking Treatment by Account

ENO Account(s)	Electric Adjustment DR/(CR)	Gas Adjustment DR/(CR)
DXD364: 364 POLES, TOWERS, & FIXTURES (D2-DD-TO) 4030AM: Depreciation Expense	($13,180)	
DXD365: 365 OVERHEAD CONDUCTORS & DEVICES (D2-DD-TO) 4030AM: Depreciation Expense	($21,320)	
DXD368: 368 LINE TRANSFORMERS (DX-DD-TO) 4030AM: Depreciation Expense	(27,999)	
DXD3691: 369.1 OVERHEAD SERVICES (DV-CC-TO) 4030AM: Depreciation Expense	($7,181)	
ADV10 – Retire Regulatory Assets/Revenue Requirements		
566000: Misc. Transmission Expenses	($192)	
568000: Maint. Supervision & Engineer	($1,976)	
913000: Advertising Expense	$149	
920000: Adm & General Salaries	($6,491)	
921000: Office Supplies And Expenses	($1,158)	
923000: Outside Services Employed	($416,472)	
926000: Employee Pension & Benefits	($2,020)	
928000: Regulatory Commission Expense	($2,833)	
930100: General Advertising Expenses	($442)	
4031AM: Deprec Exp billed from Serv Co	($849)	
408110: Employment Taxes	($370)	
411110: Prov Def Inc Tax-Cr-Op Inc-Fed	($146,995)	
411120: Prov Def Inc Tax-Cr-Op Inc-Sta	($56,755)	
1823UN: Union 1 Reg Asset	($2,619,419)	
283307: ADIT Other - Reg Assets - Fed	($254,411)	
283308: ADIT Other - Reg Assets - St	($98,228)	
546000: Operation Superv & Engineerin	($7,658)	
549000: Misc Oth Pwr Generation Exps	($18,220)	
553000: Maint-Gener & Elec Equipment	($1,283,695)	
554000: Maint-Misc Other Pwr Gen Plt	($136)	
RD407D: 407.348 REGULATORY DEBITS	($273,000)	

Attachment C
Advisor Adjustments to ENO's
Proposed Ratemaking Treatment by Account

ENO Account(s)	Electric Adjustment DR/(CR)	Gas Adjustment DR/(CR)
ADV11 – Establish Regulatory Liability		
254120: 254 REGULATORY LIABILITY MOD[67]	($31,354,992)[68]	
RD407MISO: 407.363 REGULATORY DEBITS[69]	($3,483,888)[70]	

67 ENO is recording this unamortized balance in Account 254SLB. However, this account is not part of the FRP Evaluation Filing's detailed accounts, so it cannot readily be used in our calculations. For computational convenience, an available account, 254120, was selected. ENO is not obliged to use Account 254120 when recording this regulatory liability.

68 This value is based on a publicly-available value is as of April 2023. Our recommendation is that ENO establish the regulatory liability using the balance as of August 31, 2023. *See* ENO's HSPM response to DR CNO 4-1 for this value, which reflects the accrual of "appropriate interest" through that date. Our calculated revenue and bill impacts reflect this HSPM value.

69 We did not identify the ENO amortization expense account associated with ENO Account 254SLB. For computational purposes, we selected ENO Account 407363. ENO is not obliged to use Account 407363 when charging amortization of this regulatory liability.

70 This value is based on a publicly-available value is as of April 2023. Our recommendation is that ENO establish the regulatory liability using the balance as of August 31, 2023. *See* ENO's HSPM response to DR CNO 4-1 for this value, which reflects the accrual of "appropriate interest" through that date. Our calculated revenue and bill impacts reflect this HSPM value.