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July 15, 2022

BY ELECTRONIC DELIVERY

Ms. Lora W. Johnson
Clerk of Council
Council of the City of New Orleans
City Hall, Room IE09
1300 Perdido Street
New Orleans, LA 70112

In Re: Entergy New Orleans, LLC's Formula Rate Plan Test Year 2021 Evaluation Pursuant to Council Resolution Nos. R-19-457 and R-20-344, Rider EFRP-6 and GFRP-6, Docket UD-18-07

Dear Ms. Johnson:

Enclosed please find the Advisors' Corrections Report in the above referenced docket which we are requesting be filed into the record along with this letter. The Advisors submit this filing electronically and will submit the requisite original and number of hard copies once the Council resumes normal operations, or as you direct.

Sincerely,

Jay Beatmann
Counsel

JAB/dpm
Attachment

cc: Official Service List for UD-18-07

INVESTIGATION AND REVIEW
OF
ENTERGY NEW ORLEANS, LLC'S 2022 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 15, 2022

Legend Consulting Group Limited

INTRODUCTION

On April 29, 2022, Entergy New Orleans, LLC's ("ENO") submitted to the Council its *Entergy New Orleans, LLC's 2022 Electric and Gas Formula Rate Plan Filings* ("FRP Evaluation Filing" or "instant FRP Evaluation Filing") for the twelve-month evaluation period ending December 31, 2021 ("2021 Test Year") to initiate new electric and gas rates effective with the first billing cycle of September 2021. The Advisors have reviewed ENO's Evaluation Filing, conducted inquiry through discovery, and provide this report identifying errors in ENO's Filing that would reduce ENO's proposed electric revenue increase by $15.7 million and the proposed gas revenue increase by $1.4 million. The Advisors also suggest certain mitigation measures that could reduce the rate impact on electric ratepayers by another $13.9 million while still allowing ENO a reasonable opportunity to recover its costs and earn the Council-approved rate of return. The combined effect of the Advisors' recommendations would reduce the impact of the FRP from ENO's proposed $7.62 increase on the average residential electric bill down to a $0.90 increase and would reduce ENO's proposed $2.01 increase on the average residential gas bill down to a $1.08 increase.

BACKGROUND

Prior 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[1] (*i.e.*, a 51% hypothetical equity ratio), beginning in November 2021.

On July 16, 2021, ENO submitted to the Council its 2021 Evaluation Filing for the 2020 Test Year. ENO's 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.

The 2021 Evaluation Filing proposed an increase in electric revenue of $40.00 million and an increase in gas revenues of $18.81 million. The 2021 Evaluation Filing also included outside-the-bandwidth collections of $5.17 million in electric revenues and $0.27 million in gas revenues. Accordingly, the Evaluation Filing showed an increase in revenues of $45.17 million for the electric utility and $19.08 million for the gas utility – $64.25 million electric and gas total combined revenue increase. ENO's estimated residential typical monthly bill (*i.e.*, 1,000kWh electric and 50ccf gas) increases from its 2021 Evaluation Filing were $11.03 and $14.21 for electric and gas respectively

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[1] 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 Advisors' October 1, 2021 report identified errors in ENO's 2021 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.

SUMMARY OF ADVISORS REVIEW AND ADJUSTMENTS

As part of our review and as discussed later in this report, we identified errors in the instant 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 of \$15.7 million for the electric utility and \$1.4 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 at a difficult time. 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 mitigation that are available with respect to electric customers are monies currently being held by ENO pending Council direction. These monies, totaling approximately \$13.9 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.

- *Algiers Grid Modernization*: \$0.8 million. These funds represent a Council earmark set aside in 2018. Citing progress already made regarding Algiers' distribution reliability, ENO reports these funds are available for disbursement for ratepayer benefit at the Council's direction.

- *Rider PPCACR Over/Under Balance*: \$1.3 million. These funds represent the ending over/under balance of Rider PPCACR that remain available for disbursement for ratepayer benefit at the Council's direction.

- *Reactive Power Revenue*: \$6.2 million. As a result of a series of Advisor inquiries over the past year, ENO has identified credits to ENO from other Entergy Operating Companies under the MSS-4 tariff that should have been included in Rider PPCR, but were not. These funds related to this recently disclosed billing errors are available for disbursement for ratepayer benefit at the Council's direction.

- *FAC Rate Adjustment Deferral* \$5.7 million. In January 2022, the Council set aside this amount that would have been credited to ratepayers as part of that month's FAC rate (resulting in a negative FAC rate for that month). The Council instructed ENO to hold these funds for future use at their direction. These funds are available for disbursement for ratepayer benefit at the Council's direction.

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

Table 1 Summary of Advisor Recommended Adjustments ($ in Millions)		
	Electric	Gas
ENO Proposed FRP Revenue Increase	$32.3	$3.2
Agreed-to Outside-the-Bandwidth Revenues	$4.7	-
ENO Proposed Incremental FRP Revenues	**$37.0**	**$3.2**
Advisor Adjustments		
Advisor Adjustments to Evaluation Report	($15.7)	($1.4)
Advisor Recommended Bill Mitigation Measures	($13.9)	-
Total Advisor Recommended Adjustments and Mitigations	($29.6)	($1.4)
Revenue Increase After Advisor Adjustments	**$7.4**	**$1.8**
Percent Change to ENO's Proposed Revenue Increase	(80%)	(44%)

In addition to these Advisor Adjustments and recommended bill mitigation measures, our report also discusses electric revenue allocation (decoupling) among the rate classes pursuant to EFRP Section II.B.2 and other items for Council consideration that we have identified in the course of 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 2022) 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 allocations in each test year FRP Evaluation report. In its EFRP Evaluation Filing, ENO applied decoupling in initially determining customer class revenue allocations. However, noting that its application of decoupling had "…a disproportionate effect on the Residential and Municipal Buildings rate classes"[2], 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. Table 2a presents the ENO Alternative Proposal electric revenue change by rate class.

[2] FRP Evaluation, Summary Pleading, Paragraph VII at 8

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	$173,169,512	$32,580,303	18.8%
Small Electric Service	67,608,761	181,466	0.3%
Municipal Buildings	2,373,838	500,371	21.1%
Large Electric	25,664,770	2,017,885	7.9%
Large Electric High Load Factor	93,112,367	2,412,408	2.6%
Master Metered Non-Residential	302,457	36,442	12.0%
High Voltage	5,667,145	233,503	4.1%
Large Interruptible	4,393,635	-587,389	(13.4%)
Lighting Service	4,087,042	-370,356	(9.1%)
Total	$376,379,526	$37,004,633	9.8%

1 This $37.0 million total proposed change in FRP revenue includes the agreed-to outside-the-bandwidth electric revenue of $4.7 million.

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	$173,169,512	$17,104,428	9.9%
Small Electric Service	$67,608,761	$5,967,044	8.8%
Municipal Buildings	$2,373,838	$241,145	10.2%
Large Electric	$25,664,770	$2,519,801	9.8%
Large Electric High Load Factor	$93,112,367	$9,164,294	9.8%
Master Metered Non-Residential	$302,457	$27,283	9.0%
High Voltage	$5,667,145	$852,946	15.1%
Large Interruptible	$4,393,635	$553,050	12.6%
Lighting Service	$4,087,042	$574,641	14.1%
Total	$376,379,526	$37,004,633	9.8%

1 This $37.0 million total proposed change in FRP revenue includes the agreed-to outside-the-bandwidth electric revenue of $4.7 million.

Of note, ENO's FRP Evaluation Filing assigns 88% of ENO's proposed $37 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 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	$25,640,393	$2,106,020	8.2%
Small General	5,208,868	427,840	8.2%
Large General	5,673,179	465,977	8.2%
Small Municipal	61,882	5,083	8.2%
Large Municipal	2,787,707	228,973	8.2%
Total	$39,372,030	$3,233,893	8.2%

ENO's estimate of electric and gas typical bill impacts from its Electric FRP Evaluation Filing, 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	-	$129.41	$144.35	$14.95
Small Electric	9,125	50	$1,351.21	$1,350.97	($0.24)
Large Electric	91,250	250	$10,090	$10,507	$417

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 $131.60, proposed bills would have been $146.86, and the change would have been $15.26.

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	-	$129.41	$137.03	$7.62
Small Electric	9,125	50	$1,351.21	$1,431.22	$80.01
Large Electric	91,250	250	$10,090	$10,635	$545
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 $131.60, proposed bills would have been $139.38, and the change would have been $7.78.					

Table 5 **ENO Proposed Estimated Change to Typical Gas Customer Monthly Bill**				
Rate Class	Typical Usage	Present	Proposed	Change
Residential	50 ccf	$69.09	$71.11	$2.02
Small General	500 ccf	$569.47	$583.13	$13.66
Large General	1,000 mcf	$10,036	$10,237	$201

ENO's 2021 Financial Performance

As part of ENO's discussion of its proposed $32.3 million electric revenue increase, ENO states that its Evaluation Filing "reflects an Earned Rate of Return on Common Equity ("EROE") of 5.56%",[3] well below the Council's authorized 8.85% to 9.85% ROE bandwidth range – outside of which an EFRP rate adjustment is authorized. However, ENO's EROE value is based on its *adjusted* cost of service, which includes substantial proforma cost increases for 2022, such as new plant for 2022 that was not in service in 2021. As such, ENO's 5.56% value more nearly represents the EROE ENO would experience in 2022 without a new EFRP rate adjustment (assuming ENO's 2022 kWh sales are equal to those in 2021). We asked ENO what its 2021 EROE was without these 2022 proforma adjustments to its electric cost of service, but ENO objected to our request as being irrelevant and declined to provide an answer.[4]

Using data available to us, we estimate that, absent certain 2022 proforma adjustments to ENO's cost of service that we identified, ENO's electric 2021 EROE roughly at the lower end of the EROE bandwidth range (*i.e.*, 8.85%). As we discuss later in this report, ENO experienced an anomalous loss of revenues in 2021 related to Hurricane Ida. Had ENO not experienced this loss

[3] FRP Evaluation Filing, Summary Pleading, XVI at 11. *See* also Evaluation Filing, Attachment B at 1:19.

[4] *See* DR CNO 5-7 and ENO's response thereto.

of revenue, we estimate that ENO's 2021 EROE would have been roughly 10%, outside and above the EROE bandwidth range (*i.e.*, an EROE greater than that allowed for ENO and subject to a possible downward EFRP rate adjustment).

Our 2021 EROE estimates demonstrate that EFRP rates were set correctly in 2021 – at the rates recommended by the Advisors. ENO's estimate of an electric EROE of 5.56% must be placed in the correct context, as it should not imply that ENO's present rates were set unreasonably low for its 2021 operations, which could be the incorrect inference in the Evaluation Filing's summary pleading.

Advisor Review of 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 83 single and multi-part questions; (iii) reviewed and analyzed all discovery responses; and (iv) reviewed ENO's Federal Energy Regulatory Commission ("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 2022-August 2023);
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.

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 the Table 6 below.

Table 6 Summary of Advisor Adjustments and Mitigation Measures ($ Millions) [1]			
Description	*Electric*	*Gas*	*Total Company*
ENO Proposed FRP Revenue Increase	$32.3	$3.2	$35.5
Agreed-to Outside-the-Bandwidth Revenues	$4.7	-	$4.7
ENO Proposed Incremental FRP Revenues	**$37.0**	**$3.2**	**$40.2**
Advisor Adjustments			
ADV02 – OPEB	$2.5	$1.4	$3.8
ADV03 – Meter Reading Allocator	-	-	-
ADV05 – Non-Typical Test Year	$11.1	-	$11.1
ADV06 – FIN48 Interest	$0.3	$0.0	$0.3
ADV07 – LCFC	$1.6		$1.6
ADV09 – Storm Proforma	$0.3	-	$0.3
Subtotal – Advisor Adjustments	**$15.7**	**$1.4**	**$17.1**
Total Adjusted FRP Revenue	**$21.3**	**$1.8**	**$23.1**
Advisor Recommended Bill Mitigation Measures			
Algiers Grid Modernization	$0.8	-	$0.8
Rider PPCACR Over/Under Balance	$1.3	-	$1.3
Reactive Power Revenue	$6.2	-	$6.2
FAC Rate Adjustment Deferral	$5.7	-	$5.7
Subtotal – Bill Mitigation	**$13.9**	**-**	**$13.9**
Total Adjusted and Mitigated Revenues	**$7.4**	**$1.8**	**$9.2**
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 2021 report as applicable. As discussed later in this report, some Advisor Adjustments in the 2021 report do not carry forward into this report, therefore some enumerations are skipped.

OPEB Expense (ADV02)

To satisfy its Other Post-Retirement Benefits ("OPEB") obligations to ENO employees, 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.[5] 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 $4.4 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
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"

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 2021 Evaluation Filing, that the expense portion of the OPEB Credit be excluded from the calculation of Net Utility Operating Income in the 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 AJ08F – Pension, to reverse (*i.e.*, debit O&M) $2,427,203 electric and $1,355,780 gas in OPEB expense credit (i.e., negative expense) from operating expense. ENO argues this is appropriate

5 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.

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 (positive expense),[6] 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.[7] 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.

Meter Reading Allocations (ADV03)

As part of our review, we observed that ENO has proposed an adjustment to meter reading expense related to AMI savings (902000: Meter Reading Expenses), applying the adjustment with allocator, "CM-CC-RO" that resulted in negative cost allocations to certain rate classes. This is not logical for such an expense and constitutes a minor error. In our evaluation, we employed the "CM-CC-TO" allocator that does not involve any negative cost allocations to a rate class. This adjustment has no effect on ENO's overall cost of service and is presented as Advisor Adjustment ADV03.

Non-Typical Test Year (ADV05)

ENO's proposed EFRP revenue increase of $32.3 million[8] is ENO's estimate of the differences between the revenues ENO proposes that it requires to earn its authorized 9.35% ROE and the revenues ENO collected in 2021.[9] The FRP tariffs capture this 2021 revenue as *Applicable Base Revenue*,[10] but for convenience and clarity, we refer to these 2021 revenues as "Present Revenues," meaning the base revenues that apply to the FRP Riders' rates. As such, a key consideration in whether ENO's proposed new FRP rates are just and reasonable is whether Present Revenues reasonably reflect revenues ENO would collect during the rate-effective period (*i.e.*, September

6 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.

7 *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.

8 This value excludes the $4.7 million in agreed-to outside-the-bandwidth revenues in the Evaluation Filing.

9 Specifically, revenues ENO would have earned had present rates been in effect for all of 2021.

10 *See* FRP Evaluation Filing, *AJ01A - Attachment A and G Part 1_E_WP*, Tab "PG 1_Attachment A Calculation", column e, which presents a value of $376,379,526.

2022-August 2023). If the 2021 revenues that ENO used as its Present Revenues do not reasonably reflect future base revenues, then ENO's proposed FRP rates may not be appropriate.

ENO has presented unadjusted 2021 revenues (with some months' revenues calculated as if the present FRP rates were in effect for all of 2021) as its Present Revenue estimates, without consideration of anomalous and non-recurring events that affected 2021 revenues. However, we note that the EFRP Riders allow for proforma adjustments to Present Revenues.

> *The historic data utilized in each Evaluation Report shall be based on actual results for the Evaluation Period as recorded as electric operations on the Company's books in accordance with the Uniform System of Accounts and such other documentation as may be appropriate in support of adjustments including known and measurable changes in the* ***revenues*** *or cost of providing utility service for the Evaluation Period . . .*[11] (Emphasis added.)

As such, the FRP Riders permit proforma adjustments to Present Revenues. We note that ENO has extensively employed prospective proforma adjustments to its expenses and rate base.

Hurricane Ida

As described in detail in the May 6, 2022 *Council Utility Advisors' Report* as part of the Council's after-incident review of ENO relative to its preparation and response to Hurricane Ida ("Ida Report"), ENO's electric utility experienced prolonged service outages following Hurricane Ida. As the Ida Report notes, by 7:00 PM Sunday August 29, 2021, all power in New Orleans was lost due to all of the eight power transmission paths into New Orleans being rendered out of service due to storm damage. Further, the loss of those transmission facilities resulted in a load imbalance that caused local generation (*i.e.*, NOPS) to trip off-line.

Following the service outage, on September 1, 2021, at approximately 1:00 AM (approximately 2.25 days after all eight transmission paths were lost), ENO began to provide "first light" power to some customers utilizing NOPS in coordination with a transmission path established from northeast of New Orleans. Nine days later, on Friday September 10, 2021, ENO communicated that it had restored power to 100% of customers that could safely receive power. As such, ENO's electric service was disrupted either entirely or in part over a roughly 12-day period.

We further note that the transmission facilities that failed during Hurricane Ida are owned by either Louisiana LLC ("ELL") or Cleco Power, LLC ("Cleco"). As such, the Council does not regulate the utilities that control these eight transmission paths into New Orleans. It is our understanding that ELL plans to make significant investments in its transmission plant in response to failures during Hurricane Ida.

The events of Hurricane Ida, including the catastrophic failure of all eight transmission paths into the city, is not reasonably expected to be a regularly recurring event, including in 2022. In this regard, 2021 was not a typical test year in terms of ENO's electric revenues. Yet ENO's Present Revenues reflect this service disruption. In other words, but for the service outages following Hurricane Ida, which, in our opinion, are not reflective of 2022 revenues, ENO's Present Revenues in the Evaluation Filing would be higher.

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[11] Rider Schedule EFRP-6, pg. 30.3. Rider Schedule GFRP-6 has substantially similar language at pg. 12.3.

ENO has estimated that its lost revenues related to the Hurricane Ida service outages, net of related avoided costs, a term ENO refers to as Adjusted Gross Margin, totaling $11,254,182.[12] [13] However, as we discuss below, ENO has erred by not considering proforma adjustments to Present Revenues in the context of the service outages following Hurricane Ida.

<u>Advisor Adjustment</u>

There is no evidence suggesting that the service outages following Hurricane Ida are reasonably expected to recur in 2022. The text of Rider EFRP cited above, as well as the regulatory principle of prospective ratemaking, indicate that a proforma adjustment to ENO's Present Revenues of $11,254,182 (which represents a decrease to ENO's FRP revenue requirement) still provides ENO the reasonable opportunity to earn its allowed ROE of 9.35%.

Advisor Adjustment ADV05 corrects for ENO's error of using unadjusted 2021 revenues as its Present Revenues, which if uncorrected would result in unfair overcollection by ENO due to Present Revenues that do not adjust for the non-recurring service outages related to Hurricane Ida.

Interest on FIN 48 Tax Liabilities (ADV06)

In ENO's adjustment AJ06B, ENO requests recovery of $251,959 (electric) and $21,439 (gas) in calculated interest on tax positions that in ENO's opinion do not meet the "more-likely-than-not recognition threshold"[14] of being allowed by the IRS upon audit (i.e., FIN 48 tax positions).[15] 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 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 $7.6 million Present Revenue decrease[16] (an increase to ENO's revenue requirement) to account for ENO's estimated Lost Contribution to Fixed Costs ("LCFC") related to energy sales reductions caused by the Council's Energy Smart program. This $7.6 million increase to ENO's EFRP revenue requirement was computed from the <u>2022</u> kWh Savings goal approved in Resolution R-20-51 and the Adjusted Gross Margin representing fixed cost $/kWh. The use of the actual 2021 Energy Smart program kWh reduction compared to the 2021 kWh Savings goal provides a more certain estimate for determining a LCFC

[12] *See* ENO's HSPM response to DR CNO 1-13.b. Counsel for ENO authorized the public dissemination of this value.

[13] In response to DR CNO 1-13.b, ENO did not perform an estimate related to gas. Our review of Rider PGA filings indicates no reduction in gas retail sales for the periods affected by Hurricane Ida. As such, we find no indication of a non-typical test year for ENO's gas utility revenues.

[14] *See* FASB Interpretation No. 48 at 5.

[15] *See* ENO's response to DR CNO 3-1.

[16] *See* FRP Evaluation Filing, Adjustment AJ08D.

adjustment. ENO did not nearly achieve its Council-approved Energy Smart Program Year 11 goal in 2021, and the actual LCFC ENO experienced in 2021 was $4.7 million.[17] In comparison, ENO was allowed a LCFC adjustment in the 2021 Evaluation in the amount of $6.3 million,[18] based on the 2021 kWh Savings goal. 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.[19]

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 $7.6 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 2021 compared to the LCFC estimate in the 2021 EFRP. After this Advisor Adjustment, ENO's LCFC revenue adjustment should be reduced by $1.6 million. Advisor Adjustment ADV07 effects this correction to ENO's error.

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., 2022 for the instant 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.[20]

ENO has requested a $2,367,403[21] proforma addition to distribution plant in service related to storm restoration capital costs that may be incurred in 2022 with respect to minor weather events. As with ENO's 2021 FRP Evaluation Filing, ENO errs in proposing this proforma adjustment because these estimated investment amounts do not meet the "known and measurable" standard for inclusion in the FRP Evaluation's cost of service.

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17 Lost Contribution to Fixed Costs and Utility Performance Incentive Filing for Energy Smart Program Year 11 for Entergy New Orleans, June 30, 2022.

18 *See* ENO's 2021 Evaluation Filing, Adjustment AJ08D.

19 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.

20 Rider Schedule EFRP-6, FN 1 at pg. 30.3

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

As such, consistent with our recommendations in our 2021 report, ENO erred in proposing the proforma adjustment to add $2,367,403 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 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 stated 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 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 discusses a "Decoupling Pilot Program implemented in Ordering Paragraph 26 of Resolution R-19-457. . ."[22] 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, residential capacity-related fixed cost allocation factors must be estimated since

22 FRP Evaluation Filing, Summary Pleading, VII at 8

no meter data is yet available to provide residential class demands at the required specific hours.[23] That estimation has 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 peak hour demands would not be expected to change dramatically for twelve-month periods not far removed from each 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 very different between these two periods due to the difference in the estimates of Residential peak demands. In the recent 2018 Rate Case the residential class monthly average to peak demand load factor was 66.92%, compared to the Evaluation period residential class monthly average to peak demand load factor of 50.75%. Clearly the Evaluation period estimates of Residential peak demands were much higher relative to the estimated Residential peak demands in the recent rate case.

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 and for the instant 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 periods. including references and data supporting any differences.[24] ENO did confirm that there has been no change to the methodology to produce the underlying demand data.[25] 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,[26] 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.[27] 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.[28] 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.[29]

Since ENO did not provide any worksheets to support the capacity-related fixed cost allocation factors between the recent rate case the FRP Evaluation period, the Advisors constructed an alternative which combined the capacity-related fixed cost allocation factor from available ENO data for the following four recent twelve-month periods: test year ended December 31, 2018; test year ended September 30, 2019; test year ended September 30, 2020; and test year ended

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

[24] DR CNO 3-12. 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.

[25] ENO's response to DR CNO 3-13

[26] DR CNO 4-11 and CNO 4-12.

[27] *Id*.

[28] DR CNO 4-13 and CNO 4-14.

[29] *Id*.

September 30, 2021. The kW peak demands for the four 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, given the lack of ENO supporting data needed for a more rigorous development of those allocation factors.

The results of the Advisors' 2018 Rate Case Recommended Electric Revenue Requirements by Rate Class is presented herein as Attachment A, page 1. Attachment A, page 2 presents ENO's current decoupling compliance with Rider EFRP's tariff. For Comparison, Attachment B presents the Advisors' Adjusted Revenue Requirement and Decoupling analysis for the EFRP Evaluation Period.

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 cost allocation resulted in ENO's presenting Decoupling with only increasing the Residential class low rate of return, with no change in rates of return for the other eight customer classes, such that ENO's Decoupling would have Residential class revenue increase $31.1 million of the $32.3 million EFRP revenue adjustment. In contrast, as seen in comparing Attachment A and Attachment B, the Advisors' application of Decoupling results in a 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. However, ENO only increased the rate of return to the Residential class, without any adjustments to any of the other customer classes. For example, the LIS rate of return on rate base in ENO's EFRP Evaluation decoupling proposal was unchanged from ENO's 2021 EFRP Evaluation. In contrast, the Advisors' Evaluation decoupling proposal moved several of the customer class rates of return toward the utility's rate of return as directed in Resolution R-19-457. Specifically, the Large Customers rates of return were generally lowered, and the Residential rate of return was adjusted higher toward ENO's total utility rate of return.[30]

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%. Since the change in total EFRP revenue is 9.8% of base 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.

Areas of Review not Requiring Advisor Adjustments

As part of our review of the FRP Evaluation Filing, we reviewed and evaluated each of ENO's proforma adjustments to its per-book cost of service (*i.e.*, each AJXX). In each case where we did not identify an error on the part of ENO, we did not make an Advisor Adjustment, and in cases where ENO's treatment is consistent with Council precedent and accepted regulatory ratemaking

[30] ENO proposed an alternative set of revenue adjustments that did not incorporate decoupling, as discussed on pages 3 and 4 herein.

treatment, we do not discuss these reviews further in this report. ENO's proposed ratemaking treatment for certain costs related to deficient ADIT caused by a small change in ENO's income tax rate, while not conceptually new, is discussed below. Further, we discuss an immaterial error related to Research and Experimentation ("R&E").

R&E Calculation Error

In an HSPM FRP Evaluation File, "AJ03A - ADIT_E_WP_HSPM", ENO applied an irrational and unsupported calculation methodology related to its rate base. In ENO's 2021 FRP Evaluation Filing, ENO estimated R&E costs based on a 3-year historical average. In the instant Evaluation Filing, because ENO's actual 2020 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 is not satisfactory.[31] Our estimated impact of ENO's error and inadequate justification for its error is de minimis. As such, we do not attempt to generate an Advisor Adjustment to correct ENO's error. However, inconsistent application of ratemaking principles harms the regulatory process, and ENO should refrain from such in the future.

Deficient ADIT

Changes in income tax rates affect the amount owed for future tax periods. As such, provisions for the payment of future taxes (*i.e.*, ADIT) require adjustment when tax rates change. ENO calculates that the 2022 income tax rate change caused an unprotected deficient ADIT of $0.2 million and $1.7 million for electric and gas respectively. ENO proposes to recover these amounts over 12 months in its FRP rates.[32]

ENO also calculates protected deficient ADIT of $0.5 million and $1.6 million for electric and gas respectively. These amounts must be amortized over the lives of the plant to which they relate (*i.e.*, the ARAM method). As such, the effect on ENO's annual cost of service and ratepayers is minimal related to protected deficient ADIT. We note that ENO is presently amortizing a significantly larger protected excess ADIT related to the TCJA, so this amortization adjustment is expected to partly offset an ongoing annual credit to ratepayers.

The Advisors reviewed this request regarding protected and unprotected deficient ADIT and ENO's supporting workbook. ENO's request is consistent with accepted regulatory principles, and we did not identify any errors in ENO's calculation from our review of available information. As such, we do not find error in ENO's request to recover these deficient ADIT amounts over 12 months.

Bill Mitigation Adjustments

Below, we discuss adjustments and credits that are appropriate given New Orleans's current circumstances and the magnitude of ENO's revenue requests. In each case below, our recommendations are designed to mitigate harmful ratepayer bill impacts while still allowing ENO the reasonable opportunity to earn its Council-authorized ROE of 9.35%.

[31] *See* DR CNO 5-2 and ENO's HSPM response thereto.

[32] *See* FRP Evaluation Filing, Summary Pleading, XXIV at 14.

Bill mitigation is outside the scope of the EFRP rider's provisions. The Council has the sole authority as to the appropriate use of these funds. Given ENO's significant FRP revenue request, we recommend the Council direct ENO to credit its PPCR rider rate calculation for each of the 12 months September 2022-August 2023 in equal amounts totaling $13,934,068 ($1,161,172 per month). Our typical bill impact tables presented below assume the application of these Rider PPCR credits.

Algiers Grid Modernization

As part of Council Resolution No. R-18-227, the Council earmarked $801,527 of Unprotected Excess Accumulated Deferred Income Tax related to the 2017 Tax Cuts and Jobs Act ("TCJA"). ENO identifies this balance as "subject to disbursement or use for ratepayer benefit upon Council direction".[33] Citing progress already made regarding Algiers' distribution reliability, ENO notes that "[it] will not go forward with the Algiers Grid Modernization project."[34]

Rider PPCACR Over/Under Balance

As part of the 2018 Rate Case, capacity rider PPCACR was ended and replaced with Rider PPCR. Per ENO, at its termination, Rider PPCACR had a $1,254,854 credit balance that is available for the Council to use to mitigate the bill effects of ENO's proposed EFRP rate increases.

Reactive Power Revenue

As a result of a series of Advisor inquiries over approximately the past year, ENO has reported that $6,217,187 in revenues related to *Designated Power Units* where ENO purchases capacity and energy under the MSS-4 Replacement Tariff were not properly credited to ENO. These recently disclosed MSS-4 Replacement Tariff billing errors are available for the Council to use to mitigate the bill effects of ENO's proposed EFRP rate increase.

FAC Rate Adjustment Deferral

Regarding the January 2022 Fuel Adjustment Clause ("FAC") rate that, absent Council action, would have been a negative rate, ENO was directed to fix the FAC rate at a typical $0.01/kWh and hold the difference between what would have been collected under ENO's calculated FAC rate and the fixed rate pending Council direction on how to use these funds in the future. ENO has calculated that applying the fixed FAC rate resulted in $5,660,500 in available funds. This amount is available to mitigate the bill effects of ENO's proposed EFRP revenue increase.

RATEPAYER IMPACT OF ENO'S 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 but does not reflect our recommended bill mitigation measures. Table 2a, which presents ENO's proposed change in FRP revenue is reproduced for comparison.

33 *See* ENO's response to DR CNO 1-12.

34 ENO's response to DR CNO 3-4

Table 2a **(reproduced from above)** **ENO Alternative Proposal Electric 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	$173,169,512	$17,104,428	9.9%
Small Electric Service	67,608,761	$5,967,044	8.8%
Municipal Buildings	2,373,838	$241,145	10.2%
Large Electric	25,664,770	$2,519,801	9.8%
Large Electric High Load Factor	93,112,367	$9,164,294	9.8%
Master Metered Non-Residential	302,457	$27,283	9.0%
High Voltage	5,667,145	$852,946	15.1%
Large Interruptible	4,393,635	$553,050	12.6%
Lighting Service	4,087,042	$574,641	14.1%
Total	$376,379,526	$37,004,633	9.8%

Table 8 **Advisor Adjusted Electric Change in FRP Revenues**			
Rate Class	Applicable Base Revenue	Advisor Adjusted Change in EFRP Revenue	Adjusted Change in EFRP Revenue as Percent of Applicable Base Revenue
Residential	$178,624,159	$9,348,499	5.4%
Small Electric Service	69,538,223	2,971,961	4.4%
Municipal Buildings	2,443,558	155,868	6.6%
Large Electric	26,396,768	1,984,809	7.7%
Large Electric High Load Factor	95,768,579	7,078,922	7.6%
Master Metered Non-Residential	311,084	(128,030)	-42.3%
High Voltage	5,828,781	256,762	4.5%
Large Interruptible	4,518,947	(595,278)	-13.5%
Lighting Service	4,203,610	255,413	6.2%
Total	$387,633,708	$21,328,925	5.7%

Of note, the $11,254,182 difference between Applicable Base Revenue in Table 2 and Table 8 above relates to Advisor Adjustment ADV05, as discussed in detail above. In compliance with Ordering Paragraph 26 of Resolution R-19-457, the Advisors' decoupling proposal did not change the rates of return for the Small Electric, Municipal Buildings, High Voltage, and Lighting classes from those rates of return established in the 2018 Rate Case; the rates of return for the other customer classes were adjusted towards the total utility rate of return.

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 GFRP Revenue	Proposed Change in GFRP Revenue as Percent of Base Revenue
Residential	$25,640,393	$2,106,020	8.2%
Small General	5,208,868	427,840	8.2%
Large General	5,673,179	465,977	8.2%
Small Municipal	61,882	5,083	8.2%
Large Municipal	2,787,707	228,973	8.2%
Total	$39,372,030	$3,233,893	8.2%

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	$25,640,393	$1,209,129	4.7%
Small General	5,208,868	245,636	4.7%
Large General	5,673,179	267,531	4.7%
Small Municipal	61,882	2,918	4.7%
Large Municipal	2,787,707	131,460	4.7%
Total	$39,372,030	$1,856,674	4.7%

Applying the Advisor Adjustments and bill mitigation measures results in estimated changes to typical bills as indicated in the 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	$129.41	$137.03	$130.31	($6.72)
Small Electric	9,125	$1,351	$1431	$1,357	($74)
Large Electric	91,250	$10,090	$10,635	$10,268	($367)

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 is $0.90 (130.31-129.41).

The change in typical bills for customers in Algiers are 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. For gas, all of New Orleans has the same franchise fee rate, so gas typical bill effects are the same for all ENO customers.

The 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 and Bill Mitigation Measures	Change from ENO Proposed
Residential	50 ccf	$69.09	$71.11	$70.17	($0.94)
Small General	500 ccf	$569.47	$583.13	$576.73	($6.40)
Large General	1,000 mcf	$10,036	$10,237	$10,143	($91.00)

As the data in Table 11 indicate, the estimated typical residential bill increase from present rates to those after Advisor Adjustments is $1.08 (70.17-69.09).

MATTERS POTENTIALLY AFFECTING RATES BUT NOT IN ENO'S PROPOSED FRP REVENUES

ENO has identified in its FRP Evaluation Filing, and in its responses to discovery, three matters that, if approved by the Council, would serve to increase rates, but which ENO did not include in its proposed $37.0 million EFRP revenue increase. We discuss each matter and make our recommendations to the Council below.

Miscalculation of Tax Deductions Related to Hurricane Ida

In response to Advisor discovery regarding the presentation of certain ADIT balances in the Evaluation Filing related to storm restoration costs,[35] ENO reported that it had miscalculated certain tax deductions associated with Hurricane Ida. Specifically, ENO states that in improperly included ADIT related to cost of removal and casualty loss deductions, which it claims it should have deferred for consideration in its anticipated Hurricane Ida cost securitization filing. Further, this miscalculation required that ENO amend its FERC Form 1 Annual Report for 2021, which amendment was filed with FERC on July 5, 2022.

This miscalculation and inadvertent inclusion of ADIT in the Evaluation amounts to a $24.0 million understatement of ENO's electric rate base, according to ENO. ENO estimates that the annual revenue effect of this error is to increase ENO's EFRP revenue by $2.1 million.

While ENO has offered certain recalculated worksheets supporting this amount, they were provided late on July 7, 2022, or less than eight calendar days before the date of this report. As such, it is not possible to completely review through discovery, or otherwise validate these new worksheets that, if properly constructed, present a substantial change to the makeup of ENO's Evaluation Filing. Upon a more complete review of this matter, and pursuant to discussions with the Parties to this proceeding, the Advisors will be prepared to recommend a ratemaking treatment to the Council.

ENO states that it intends to propose this $24.0 million debit (*i.e.*, increase) to its rate base pursuant to provisions in Rider EFRP no later than July 15, 2022 (also the date of this report, which is filed under these same provisions).[36] If ENO makes such a filing, Rider EFRP provides that this proposed rate base debit, along with the Advisor Adjustments recommended in this report, as well as any other filings by Parties to the instant proceeding, may be reviewed over a 25-day period to resolve any differences. To the extent the Parties work together and reach agreement on any of the several recommendations that may be filed on July 15, 2022, new EFRP rates may be calculated, which could include the effect of correcting for ENO's miscalculation.

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

ENO's prayer for relief includes the request,

> That the Council authorize ENO to file a report by October 31, 2022 reporting the outside-the-bandwidth-formula revenue amounts actually recovered between November 1, 2021 through August 31, 2022 and authorize ENO to include any recovery deficiency (or excess) in the over/under provision of the Fuel Adjustment

35 *See* DR CNO 5-3.

36 *See* Rider EFRP Section II.B.3, which says in part, "If any of the Parties should detect an error(s) (as distinguished from a regulatory issue(s)) in the application of the principles and procedures contained in Section II.C below, such error(s) shall be formally communicated in writing to the Company and/or other Parties by July15 . . .".

> Clause or the Purchased Gas Adjustment Clause in the December 2022 billing month, as appropriate.[37]

As part of the 2021 FRP Evaluation, ENO was allowed an outside-the-bandwidth recovery of $5,165,113 electric and $273,298 gas. The FRP rates as part of the 2021 FRP Evaluation were unusual in that they will be in effect for ten months (November 2021-August 2022), rather than the customary twelve months. As such, it is plausible that ENO will not have had the reasonable opportunity to recover this $5.44 million amount.

ENO proposes that the Council allow it to true-up the amount it actually collects from November 2021-August 2022 with the approved $5.44 million amount and place the deficiency (or excess) in the over/under balance of the Fuel Adjustment Clause Rider ("FAC") and the Purchased Gas Adjustment Clause Rider ("PGA") for electric and gas respectively. ENO requests to effect this true-up by filing a report by October 22, 2022.

We agree that ENO may not have been allowed the reasonable opportunity to recover a Council-authorized revenue amount and that such a reasonable opportunity was implied by the amounts for inclusion in FRP rates. However, ENO is requesting a guaranteed collection through a true-up, which is not the nature of FRP rates, and which was not approved by the Council. Further the FAC and PGA Riders are volumetric with allocations different from the FRP Riders. As such, recovery of these revenue requirements through volumetric riders somewhat distorts relative bill impacts among the rate classes.

To allow ENO the reasonable opportunity to collect its allowed outside-the-bandwidth amounts from the 2021 FRP Evaluation, we recommend ENO be allowed recovery, outside the bandwidth, of these revenue amounts for the months September 2021 and October 2021 (the months missing from what would have been a full 12-month rate effective period for the 2021 FRP Evaluation), based on ENO's actual billing determinants for these months. ENO has calculated this electric amount to be $899,091,[38] and the gas amount to be $41,061.[39]

The treatment for these revenues falls outside of identifying errors in ENO's Evaluation Filing.[40] The FRP tariff provides for a 25-day period for Parties to the proceeding to work together and reach agreement where possible regarding issues raised by the Parties. We believe this matter can be addressed through such negotiations.

Income Tax Rate Increase

ENO's prayer for relief includes the request,

> That the Council authorize ENO to accrue a regulatory asset and to defer the increase in federal and state income tax expense due to state income tax changes for the period from January 1, 2022 through the effective date of the FRP Rate Adjustments resulting from this proceeding.[41]

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37 *See* FRP Evaluation Filing, Summary Pleading at 29.

38 *See* DR CNO 5-5 and ENO's response thereto.

39 *See* DR CNO 5-6 and ENO's response thereto.

40 *See* Rider EFRP Section II.B.3.

41 *See* FRP Evaluation Filing, Summary Pleading at 29.

As a result of changes to Louisiana law, effective January 1, 2022, ENO's federal-state combined effective income tax rate increased from 26.0781% to 26.9250%.[42] ENO's proposed FRP revenue increases, including as adjusted by the Advisors, reflect this increased cost of service. This effective tax rate increase caused two effects for Council consideration, deficient ADIT, which we discuss earlier in this report and regulatory lag, which we discuss below.

Regulatory Lag

From January 1, 2022 through August 31, 2022 (eight months), ENO's present rates do not reflect the increase to ENO's cost of service related to the 2022 income tax rate increase. The circumstance of a utility's cost of service changing before new rates can be set is referred to as *regulatory lag*. Regulatory lag is an accepted risk to a utility, and its effects can be positive (*i.e.*, unrecovered costs) or negative (*i.e.*, recovery in excess of actually incurred costs). ENO's costs of service change regularly throughout a year between FRP evaluations, causing both positive and negative regulatory lag effects.

ENO did not estimate the total change to its cost of service over this eight-month period, but nonetheless proposes that "the Council authorize ENO to defer the increase in federal and state income tax expense . . ."[43] over this eight-month period.

The Council considered the possibility of ENO experiencing extraordinary cost changes and when to allow ENO appropriate relief. ENO's EFRP rider says,

> It is recognized that from time to time ENOL may experience extraordinary increases or decreases in costs that occur as a result of actions, events, or circumstances beyond the control of the Company. Such costs may significantly increase or decrease the Company's revenue requirements and, thereby, require rate changes that this Rider EFRP is not designed to address. Should ENOL experience such an extraordinary cost increase or decrease, excluding costs recovered via the Fuel Adjustment Clause, having an annual revenue requirement impact exceeding **$6 million** on a total electric Company basis then either the Company or the Council may initiate a proceeding to consider a pass-through of such extraordinary cost increase or decrease.[44] (Emphasis added.)

Rider GFRP-6 has substantially similar language, except the threshold there is $1 million. While ENO has not provided an estimate of the amount it requests to defer, it is unlikely the amount will exceed the $6 million electric and $1 million thresholds provided by the FRP riders.[45]

We recommend the Council not authorize ENO's request to defer the regulatory lag effects of the change to ENO's income tax rate, as the FRP riders clearly provide for the regulatory treatment of

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42 *See* FRP Evaluation Filing, Summary Pleading, XX at13.

43 FRP Evaluation Filing, Summary Pleading, XXI at 13

44 Rider EFRP-6, Section III.A.

45 Changes in income tax rates are reflected in ENO's Weighted Average Cost of Capital ("WACC"). ENO's 2021 FRP Evaluation Filing's before-tax WACC was 8.57%, its electric rate base was $1.128 billion, and its required return on rate base was $96.6 million ($96.6=$1.128 * 8.57%). In the instant FRP Evaluation, ENO's before-tax WACC is 8.64%, with the increase in part due to ENO's increased income tax rate. This 7bp increase to ENO's before-tax WACC, multiplied by $1.128 billion yields an approximate $0.9 million annual increase to ENO's electric cost of service, which over eight months yields an approximate $0.6 million deferral per ENO's request.

extraordinary increases to its costs, and the instant circumstances to not rise to the Council's threshold for such.

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.

NJ Customer Cost of Service Required but not Performed.

In Advisors' Data Request 2-12, 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.[46] ENO's response was unacceptable, referring to a whereas paragraph that the NJ Study was to accompany the 2020 GFRP Filing. ENO should comply with the Council's directive to perform a NJ Study.

Using AMI Capability to Develop Cost Allocation Factors

Considering the lack of support ENO provided for a rigorous analysis of capacity-related allocation factors, 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 demand-related cost allocation factors, when one or more rate classes' contribution to the peak loads cannot be calculated from meter data.[47] ENO was unresponsive to that Data Request ("DR"), referring instead to statistically designed samples to develop rate class demands, but which ENO would not, or could not, provide to the Advisors. The Advisors followed up with DR CNO 4-4, to which ENO responded that upgraded systems and/or increases in resources may be required.[48] 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. More technical discussions with ENO are required to clarify this issue.

Pension Rate Base Debit

In ENO's 2021 Evaluation, ENO proposed a prepaid pension rate base debits of $35.2 million and $7.7 million for electric and gas respectively. Employing the same methodology, in the instant FRP Evaluation, ENO proposes prepaid pension rate base debits (assets) of $32.4 million and $6.6 million for electric and gas respectively. As in our 2021 report, we do not find error with ENO's calculation of these values as part of its FRP Evaluations because ENO employs the same methodology allowed in the 2018 Rate Case. However, in our 2021 report, we discussed in detail our concerns regarding several aspects of ENO's proposed pension asset ratemaking treatment.[49]

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[46] 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."

[47] *See* DR CNO 3-9 and ENO's response thereto.

[48] 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."

[49] *See* the Advisors' 2021 FRP Report at 24-27.

In summary, ENO has not demonstrated that its Pension Asset proposal appropriately recovers expenses actually incurred. Relative to the definition of a Pension Asset being the amount by which cumulative ENO contributions to a pension trust exceed cumulative pension expense, ENO's definition of Prepaid Pension Costs does not directly reflect cash contributions to the pension trusts or actual financing costs incurred by ENO. Rather, ENO's defined Pension Asset relies on actuarial calculations, which themselves are highly dependent on assumptions and market performance information. We retain these concerns for the current FRP Evaluation.

Notwithstanding our continuing concerns, an Entergy subsidiary, System Energy Resources, Inc., which owns 90% of the Grand Gulf Nuclear Station and sells 17% of its share of that unit's output to ENO, has filed before the Federal Energy Regulatory Commission ("FERC") for substantially the same pension asset ratemaking treatment that ENO employs in the FRP Evaluation: FERC Docket No. ER22-24 *et. al*. As such, the Council may benefit from information that may be revealed in that FERC proceeding, possibly before the Council may take-up a new rate case regarding ENO. We believe this FERC docket offers an administratively efficient proceeding to investigate the relevant pension asset issues and that further detailed scrutiny of ENO's pension debits in the FRP Evaluation process would be duplicative.

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.[50]

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.[51]

The Advisors have on multiple occasions expressed concern regarding the bill impact related to GIRP investments. While the Advisors have stated that replacement of older, less reliable, pipe materials is consistent with industry practice, the pace of GIRP is projected to impose a heavy ratepayer burden.[52]

ENO states that its existing GIRP replacement schedule through 2022 eliminates the vast majority of the legacy utilization-pressure system, which is a major objective of GIRP.[53] As such, ENO proposes modifying its existing GIRP program timeline starting with 2023.[54] ENO's 2022 GIRP capital investment forecast amount is in line with past years' expenditures.[55] While ENO broadly

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50 *See* New Orleans Gas System Infrastructure Replacement Update, October 27, 2016, slide 9.

51 *See* GIRP Working Group – Gas Ops – v5 draft, February 19, 2020, slide 4.

52 *See* Docket No. UD-18-07, Exhibit BSW-5.

53 *See* 2021 FRP Evaluation, ENO's response to DR CNO 2-8.

54 See *Id*.

55 *See* DR CNO 4-1 and ENO's HSPM response thereto for the exact HSPM value.

represents that GIRP investments will substantially slow-down effective with the 2023 GFRP Evaluation Filing, GFRP rates remain sufficiently elevated (*i.e.*, ENO proposes a GFRP rate of 47.7465%[56]) 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 the following mitigation measures.

Depreciation Schedule

ENO's Gas Infrastructure Replacement Project primarily employs High Density Polyethylene ("HDPE") pipe, which ENO refers to as "plastic".[57] 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.[58] While approving the 3.33% depreciation rate for HDPE pipe in Resolution R-19-457, the Council directed ENO, the Advisors, and Intervenors to explore bill mitigating measures.[59]

As we discuss below, a 30-year depreciation schedule for GIRP investments is outside the industry range. ENO should again employ a 40-year depreciation schedule (specifically a 2.34% depreciation rate) commencing September 1, 2022 (when new rates under the FRP become effective).

Further, we note that a 40-year depreciation schedule for HDPE pipe as employed by ENO, 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."[60] 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, 2022, 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).

Errors Not Continued in the Instant Evaluation Filing

We identified certain errors in ENO's 2021 FRP Evaluation Filing that we did not identify in the instant FRP Evaluation Filing. As such the related Advisor Adjustments in our 2021 report are not continued in the current report for these matters. While ENO has not in any way indicated agreement with our arguments in our 2021 report, we consider the fact that the following ratemaking treatments from the 2021 Evaluation Filing did not continue into the instant FRP

56 *See* GFRP Evaluation, Attachment A (gas).

57 ENO Account 376.3 Mains-Plastic

58 *See* Council Resolution No. R-17-38, Ordering Paragraph 2.

59 *See* Council Resolution No. R-19-457, Ordering Paragraph 10.c.

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

Evaluation Filing as a welcome step toward a more productive and reasonable regulatory relationship between ENO and the Council.

BRAR Revenues

ENO included revenues from Rider BRAR in its presentation of Applicable Base Revenue in its 2021 Evaluation Filing. In our 2021 report, we objected to this inclusion, primarily because Rider EFRP's tariff language specifically excludes Rider BRAR. Our review indicates that ENO did not continue this ratemaking treatment in the instant Evaluation Filing. As such, we are not required to reverse any BRAR revenue in this report.

Gas Utility Conflict Survey

In its 2021 FRP Evaluation, ENO proposed to increase its gas rate base by approximately $1.8 million to reflect then expected 2021 gas utility conflict survey expenses. We found that ENO had erred in its proposed proforma adjustment by proposing to defer (and earn a return on the deferred balance) an expense that had not yet been incurred. ENO is not continuing this proposed treatment in the instant FRP Evaluation. As such no Advisor Adjustment to reverse this proforma is required.

Union PB1 Outage Cost Deferral

In its 2021 FRP Evaluation Filing, ENO proposed to defer approximately $3.9 million in then expected 2021 O&M related to a maintenance outage at the Union PB1 generating unit. We found that ENO had erred in its proposed proforma adjustment by proposing to defer (and earn a return on the deferred balance) an expense that had not yet been incurred. ENO is not continuing this proposed treatment in the instant FRP Evaluation. We note that Union PB1 did incur a maintenance outage in 2021, and ENO has deferred this outage's O&M costs for recovery over a 3-year period; this ratemaking treatment is reasonable and appropriate for a significant intermittent cost incurred during the evaluation period. As such no Advisor adjustment is required in the current report.

AMI Meter Reading Expense

In ENO's 2021 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 instant FRP Evaluation Filing, ENO's adjusted Meter Reading Expense is a de minimis amount reasonably consistent with a completed AMI deployment. As such, no Advisor Adjustment is required in the current report.

NOPS Deferral Balance

In ENO's 2021 FRP Evaluation Filing, we identified a minor error in the amortization expense and regulatory asset balance related to revenues related to NOPS that were deferred from NOPS's commercial operation date until such revenue requirements commenced recovery through rates. Our review indicates that the current Evaluation Filing has corrected this minor error, and related workpapers indicate a correct calculation for future test years.

Regulatory Asset Proformas

In ENO's 2021 FRP Evaluation Filing, we found that ENO erred by not proforming the balances of certain regulatory assets as of December 31, 2021, as these future balances were known and measurable and their amortization expenses were reflected in ENO's cost of service. These regulatory assets were related to the Algiers customer migration and the 2018 Rate Case expenses. Our review of the current FRP Evaluation Filing indicates that ENO has proformed these regulatory assets' balances as of December 31, 2022.

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
2022 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	1,196,994,272	722,368,878	161,326,690	6,630,706	66,650,358	210,332,100	812,277	9,967,356	7,598,534	11,307,373
2	ENO Required Rate of Return on Rate Base After taxes	6.88%									
3	ENO Required Rate of Return on Rate Base Including taxes	8.64%	3.11%	18.32%	20.21%	14.74%	16.90%	15.48%	13.05%	13.20%	20.16%
4	Return on Rate Base including income taxes	103,420,305	22,447,336	29,555,050	1,340,125	9,822,656	35,546,160	125,777	1,300,325	1,003,309	2,279,566
5	Operation & Maintenance Expense	474,368,355	251,201,923	64,664,405	2,321,036	29,561,185	105,740,114	359,116	9,313,655	8,772,267	2,434,655
6	Gains from Disp of Allowances	-	-	-	-	-	-	-	-	-	-
7	Regulatory Debits & Credits	5,810,431	3,499,753	793,386	32,107	322,744	1,017,703	3,998	48,521	36,199	56,020
8	Interest on Customer Deposits	778,086	469,564	104,868	4,310	43,325	136,723	528	6,479	4,939	7,350
9	Other Credit Fees	319,238	192,656	43,026	1,768	17,776	56,096	217	2,658	2,026	3,016
10	Depreciation & Amortization Expense	66,122,765	40,358,767	8,943,001	364,168	3,570,686	11,287,361	41,407	526,562	400,224	630,589
11	Amortization of Plant Acquisition Adjustment	1,190,642	668,427	163,813	5,925	73,961	239,947	896	21,849	14,466	1,357
12	Taxes Other than Income	17,541,944	10,616,692	2,408,979	94,157	948,199	3,035,838	11,553	154,611	120,546	151,369
13	Adjustment (Bad Debt, Reg. Exp. & Tax Difference)	1,819,401	1,504,304	97,244	5,145	51,963	145,426	698	8,431	5,275	915
14	SSCR (recovered w/ a Rider)	-									
15	SSCO (recovered w/ a Rider)	-									
16	EECR (recovered w/ a Rider)	-									
17	Less Credit to COS from Other Operating Revenue	.	(42,450,134)	(13,592,569)	(498,967)	(6,953,952)	(27,427,765)	(84,428)	(2,529,895)	(2,871,083)	(825,835)
18	**Total Cost of Service**	**574,136,541**	**288,509,288**	**93,181,202**	**3,669,776**	**37,458,543**	**129,777,602**	**459,762**	**8,853,197**	**7,488,168**	**4,739,003**
19	Less Present Revenue [1]	541,831,908	257,380,919	93,430,117	3,210,481	35,859,938	128,907,209	415,922	9,008,815	8,269,011	5,349,496
20	**= Revenue Deficiency (Excess)**	**32,304,633**	**31,128,369**	**(248,915)**	**459,294**	**1,598,604**	**870,393**	**43,841**	**(155,618)**	**(780,843)**	**(610,492)**
21	Percent Increase on Total Revenues	6.0%	12.1%	-0.3%	14.3%	4.5%	0.7%	10.5%	-1.7%	-9.4%	-11.4%

Attachment B

Attachment B
FRP Revenue Change
Calculation by Rate Class

Description	Total Advisor Adjustments	Combined Total Company Adjusted	Residential	Small Electric Service	Municipal Buildings	Large Electric	Large Electric High Load Factor	Master Metered Non-Residential	High Voltage	Large Interruptible	Lighting Service
	Total Advisor Adjustments	Combined Total Company Adjusted	Residential	Small Electric Service	Municipal Buildings	Large Electric	Large Electric High Load Factor	Master Metered Non-Residential	High Voltage	Large Interruptible	Lighting Service
Rate Base	(2,367,403)	1,194,626,869	673,736,144	171,587,992	6,150,014	72,903,738	238,186,026	528,955	10,378,300	8,678,000	12,477,699
ENO Required Rate Of Return On Rate Base Including Taxes	8.64%	8.64%	3.67%	18.30%	20.00%	10.75%	13.81%	19.00%	13.96%	12.40%	20.15%
Return On Rate Base Including Income Taxes	(204,544)	103,215,762	24,726,116	31,400,603	1,230,003	7,837,819	32,881,581	100,502	1,448,811	1,076,072	2,514,256
O&M Expense	(2,427,203)	471,941,153	235,167,573	67,094,393	2,209,289	31,917,219	114,317,613	238,392	9,340,854	8,789,478	2,866,342
Gains From Disposition Of Allowances	0										
Regulatory Debits & Credits	0	5,810,431	3,282,260	845,816	28,713	353,655	1,144,879	2,593	50,696	39,303	62,516
Interest On Customer Deposits	0	778,086	449,778	112,151	3,299	47,199	145,645	391	6,963	3,870	8,790
Other Credit Fees	(251,959)	67,279	37,959	9,661	343	4,108	13,407	29	583	487	701
Depreciation & Amortization Expense	(55,328)	66,067,437	38,055,676	9,483,525	332,715	3,888,564	12,597,064	27,851	550,221	434,228	697,595
Amortization Of Plant Acquisition Adjustment	0	1,190,642	617,459	172,960	5,675	81,350	271,110	572	22,859	15,649	3,009
Taxes Other Than Income	0	17,541,944	10,019,173	2,548,942	88,470	1,031,445	3,384,206	8,585	161,292	130,021	169,810
Adjustment (Bad Debt, Reg. Exp. & Tax Difference)	132,484	1,951,885	1,613,843	104,325	5,519	55,747	156,016	749	9,045	5,659	982
SSCR (Recovered w/ A Rider)	0	0	0	0	0	0	0	0	0	0	0
SSCO (Recovered w/ A Rider)	0	0	0	0	0	0	0	0	0	0	0
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	(97,234,628)	(42,450,134)	(13,592,569)	(498,967)	(6,953,952)	(27,427,765)	(84,428)	(2,529,895)	(2,871,083)	(825,835)
Total Cost Of Service	(2,806,550)	571,329,991	271,519,704	98,179,807	3,405,059	38,263,152	137,483,754	295,235	9,061,428	7,623,683	5,498,168
EAC Revenues		*454*	*6*	*92*	*3*	*59*	*236*	*1*	*25*	*26*	*6*
FAC Revenues		*96,696,816*	*39,843,750*	*13,637,926*	*528,532*	*7,115,492*	*28,567,856*	*93,992*	*2,794,189*	*3,278,056*	*837,022*
FRP Revenue		*66,181,517*	*32,969,743*	*14,540,346*	*371,066*	*4,338,912*	*11,766,051*	*36,753*	*914,587*	*692,301*	*551,759*
Interdepartmental Sales		-	-	-	-	-	-	-	-	-	-
LCFC Revenue	1,614,976	*(6,023,370)*	*(2,919,391)*	*(1,032,670)*	*(37,315)*	*(391,774)*	*(1,421,636)*	*(4,617)*	*(86,509)*	*(67,069)*	*(62,389)*
MISO Revenues		*2,996,877*	*1,608,996*	*418,426*	*14,245*	*188,128*	*634,965*	*2,358*	*56,565*	*67,851*	*5,344*
Purchase Power Revenues		*(10,991,543)*	*(4,586,412)*	*(1,506,532)*	*(100,537)*	*(950,607)*	*(3,389,313)*	*(13,784)*	*(313,991)*	*(77,807)*	*(52,560)*
Sales Revenue	11,254,182	*405,840,316*	*196,701,617*	*69,578,868*	*2,514,213*	*26,396,768*	*95,786,429*	*311,084*	*5,828,781*	*4,518,947*	*4,203,610*
Less Present Revenue	12,869,158	554,701,067	263,618,309	95,636,456	3,290,207	36,696,977	131,944,588	425,786	9,193,645	8,412,306	5,482,792
FRP Revenue Change	**(15,675,708)**	**16,628,925**	**7,901,395**	**2,543,351**	**114,853**	**1,566,175**	**5,539,166**	**(130,551)**	**(132,217)**	**(788,623)**	**15,376**
	Percent Total Revenue Increase	3.00%	3.00%	2.66%	3.49%	4.27%	4.20%	-30.66%	-1.44%	-9.37%	0.28%

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 715926NS1: ASC 715 NSC - Emp Pens & Ben	(2,427,203)	(1,335,780)
ADV03 – Meter Reading Expense Allocator		
OMCA902: 902 METER READING EXPENSE 902000: Meter Reading Expenses CM-CC-RO	418,121	-
OMCA902: 902 METER READING EXPENSE 902000: Meter Reading Expenses CM-CC-TO	(418,121)	-
ADV05 – Test Year Revenues		
RSRRPPC: 440-445 SALES–RETAIL - PURCHASED POWER CAPACITY REVPPC: Purchase Power Revenues	11,254,182	-
ADV06 – FIN48 Interest		
OCFBL: BANK LOANS & FIN48 - INTEREST EXP COSOCF: Other Credit Fees & FIN48 Int	(251,959)	(21,439)
ADV07 – LCFC		
RSRRLCF: 440-445 SALES–RETAIL - LCFC REVLCF: LCFC Revenue	1,614,976	-
ADV09 – Storm Proforma Costs		
PLD361: 361 STRUCTURES & IMPROVEMENTS (DS-DD-TO) 1010AM: Electric Plant In Service	(14,695)	-
PLD362: 362 STATION EQUIPMENT (DS-DD-TO) 1010AM: Electric Plant In Service	(373,069)	-
PLD364: 364 POLES, TOWERS, & FIXTURES (D2-DD-TO) 1010AM: Electric Plant In Service	(417,038)	-
PLD365: 365 OVERHEAD CONDUCTORS & DEVICES (D2-DD-TO) 1010AM: Electric Plant In Service	(627,436)	-
PLD368: 368 LINE TRANSFORMERS (DX-DD-TO) 1010AM: Electric Plant In Service	(711,403)	-
PLD3691: 369.1 OVERHEAD SERVICES (DV-CC-TO) 1010AM: Electric Plant In Service	(223,763)	-
DXD361: 361 STRUCTURES & IMPROVEMENTS (DS-DD-TO) 4030AM: Depreciation Expense	(140)	-
DXD362: 362 STATION EQUIPMENT (DS-DD-TO) 4030AM: Depreciation Expense	(4,040)	-
DXD364: 364 POLES, TOWERS, & FIXTURES (D2-DD-TO) 4030AM: Depreciation Expense	(9,236)	-
DXD365: 365 OVERHEAD CONDUCTORS & DEVICES (D2-DD-TO) 4030AM: Depreciation Expense	(14,702)	-
DXD368: 368 LINE TRANSFORMERS (DX-DD-TO) 4030AM: Depreciation Expense	(21,082)	-

Attachment C **Advisor Adjustments to ENO's** **Proposed Ratemaking Treatment by Account**		
ENO Account(s)	**Electric Adjustment DR/(CR)**	**Gas Adjustment DR/(CR)**
DXD3691: 369.1 OVERHEAD SERVICES (DV-CC-TO) 4030AM: Depreciation Expense	(6,127)	-