# INVESTIGATION AND REVIEW
# OF
# ENTERGY NEW ORLEANS, LLC'S 2021 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

**PUBLIC REDACTED VERSION**

OCTOBER 1, 2021

Legend Consulting Group Limited

## INTRODUCTION

On July 16, 2021, ENO submitted to the Council its *Entergy New Orleans, LLC's 2021 Electric and Gas Formula Rate Plan Filings* ("Evaluation Filing") for the twelve-month evaluation period ending December 31, 2020 ("2020 Test Year") to initiate new electric and gas rates effective with the first billing cycle of November 2021. The Advisors have reviewed Entergy New Orleans, LLC's ("ENO" or "Company") Evaluation Filing and provide this report identifying errors in ENO's Filing that would reduce the proposed electric rate increase by $10.27 million and the proposed gas rate increase by $4.47 million. The Advisors also suggest certain mitigation measures that could reduce the rate impact on ratepayers by another $15.00 million for electric ratepayers and $1.49 million for gas ratepayers while still allowing ENO a reasonable opportunity to recover its costs and earn the Council-approved rate of return, as well as various other adjustments, in the midst of the COVID-19 pandemic.

## BACKGROUND

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 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 Evaluation Filing proposes an increase in electric revenue of $40.00 million and an increase in gas revenues of $18.81 million. The Evaluation Filing also includes outside-the-bandwidth collections of $5.17 million in electric revenues and $0.27 million in gas revenues. Accordingly, the Evaluation Filing shows 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 estimates in the Evaluation Filing that, with ENO's proposed revenue increases, a typical residential electric customer using 1,000 kWh per month would experience a bill increase of $11.03 per month (Legacy ENO customer) and a typical residential gas customer using 50 ccf per month would experience a gas bill increase of $14.21 per month.

Per the EFRP and GFRP Rider schedules, the Council's Advisors ("Advisors") and all intervenors ("Intervenors"), which together with ENO, collectively, are referred to as the "Parties," have 75

[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".

days 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. Per Council Resolution R-21-295, the deadline for Parties to review the Evaluation Filing is October 1, 2021. After which, ENO then has 25 days to review any identified corrections, to work with the other Parties to resolve any differences and to file revised Rate Adjustments reflecting all corrections upon which the Parties agree.

The proposed rates, as adjusted to correct for any errors identified by and agreed to by the Parties, will automatically go into effect the first billing cycle of November 2021, without Council action.

## SUMMARY OF ADVISORS REVIEW AND ADJUSTMENTS

As part of our review and as discussed later in this report, we identified errors in the Evaluation Filing and prepared Advisor Adjustments to correct them, that if agreed to by the Parties, would result in a reduction to the ENO proposed increases of approximately of $10.27 million for the electric utility and $4.47 million for the gas utility, which we refer to as Advisor Adjustments. However, even with these substantial Advisor Adjustments, the magnitude of the FRP 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 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.

Three potential sources of mitigation that are available with respect to electric customers are monies currently being held by ENO pending Council direction. These monies 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.

*FERC Docket No. ER13-1508 Refund* – In FERC Docket No. ER13-1508 et al., pursuant to Opinion No. 575, Entergy Louisiana, LLC and Entergy Arkansas, LLC ("EAL") paid to ENO $6.1 million. On August 20, 2021, Committee Chair Helena Moreno asked ENO to hold this refund until the Council provided guidance as to how the refund shall be utilized. These refund monies could be utilized to mitigate the impact of a rate increase to ratepayers. However, they should not simply be applied as a FRP Rate Adjustment. This is primarily because the rate-effective period[2] of the instant FRP evaluation is ten months (November 2021-August 2022) instead of the customary twelve-month period between FRP adjustments. As such, ratepayers likely would realize in their bills only roughly ten-twelfths of the refund credit if it were applied to the FRP's rates in the instant proceeding.

Further, even if the instant rate-effective period were twelve months, the FRP does not guarantee a 1:1 relationship between the refund credit applied and ratepayer savings, as the FRP riders are not exact cost recovery mechanisms. As we discuss in greater detail later in this report, to ensure ratepayers enjoy the full benefit of this FERC refund, we recommend that it be applied first to satisfy the $5.17 million outside-the-bandwidth revenue amount and that the remaining $0.9 million be applied in ten equal increments as a credit to the Fuel Adjustment Charge rider ("FAC"), November 2021-August 2022.

[2] Rate-effective period refers to the period during which the new FRP Riders' rates are expected to be in place. The regulatory principle of prospective ratemaking involves setting rates that will allow ENO the reasonable opportunity to earn its allowed ROE (9.35%) during the rate-effective period.

*2020 DOE Refund* – In late 2020 System Energy Resources, Inc. was awarded approximately $40.5 million from the Department of Energy ("DOE") for interim spent fuel damages from 2012-2017. ENO's share of the award is approximately $6.2 million. ENO is holding these funds for Council direction with regards to their use.[3] Similar to the ER13-1508 Refund discussion, we do not recommend that these funds be applied directly to the FRP adjustment. Rather, we recommend that the $6.2 million be applied in ten equal increments as a credit to the FAC, November 2021-August 2022.

*Off System Sales Refund* – In FERC Docket No. EL09-61, ENO was provided approximately $7 million as a refund credit related to EAL's off-system sales practices. The Council employed this credit to fund the City Council Cares ("CCC") program; however, $2,691,055 of these funds remain unapplied. As with the other mitigation measures, we recommend that this amount be applied in ten equal increments as a credit to the FAC, November 2021-August 2022.

In addition to these three mitigation opportunities, which the Council can enact at its discretion, we recommend other mitigation ratemaking treatments with respect to gas, which we discuss in detail later in this report. These mitigation measures fall outside of the FRP tariff's provisions, but if enacted would mitigate bill impacts while still allowing ENO the reasonable opportunity to earn its allowed-Return on Equity ("ROE") of 9.35%.

Table 1 presents a summary of the total 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**[1] | **$45.17** | **$19.08** |
| Advisor Adjustments | | |
| Advisor Adjustments to Evaluation Report | $(10.27) | $(4.47) |
| Advisor Recommended Bill Mitigation Measures | $(15.00) | ($1.49) |
| Total Advisor Recommended Adjustments and Mitigations | $(25.27) | ($5.96) |
| **FRP Revenue Increase After Advisor Adjustments** | **$19.90** | **$13.12** |
| Percent Change to ENO's Proposed FRP Revenue Increase | -55.9% | -31.2% |

1. These values include outside-the-bandwidth revenue amounts of $5.17 million electric and $0.27 million gas. The electric value does not include approximately $5.3 million in NOSS-related revenues that are presently recovered in Rider PPCR and which are being realigned to Rider EFRP.

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

[3] See ENO's response to DR CNO 9-17.c.

Section II.B.2 and other items for Council consideration that we have identified in the course of our investigation and review.

## ENO'S EVALUATION FILING

ENO's 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 November 2021) reset each of its electric and gas rates consistent with the FRPs' midpoint ROE of 9.35%. The below tables summarize ENO's proposed FRP revenue increases and rate proposals by rate class.

**Table 2**
**ENO's Proposed 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 | $ 176,876,728 | $ 24,218,599 | 13.7% |
| Small Electric Service | $ 66,333,601 | $ 10,230,103 | 15.4% |
| Municipal Buildings | $ 1,994,937 | $ 289,852 | 14.5% |
| Large Electric | $ 26,984,373 | $ 4,058,662 | 15.0% |
| Large Electric High Load Factor | $ 92,536,682 | $ 4,449,625 | 4.8% |
| Master Metered Non-Residential | $ 209,176 | $ 75,231 | 36.0% |
| High Voltage | $ 5,525,819 | $ 234,227 | 4.2% |
| Large Interruptible | $ 3,946,033 | $ 1,223,272 | 31.0% |
| Lighting Service | $ 4,187,282 | $ 521,864 | 12.5% |
| Total | $ 378,594,630 | $ 45,301,435[1] | 12.0% |

1 This $45.3 million value includes $5.3 million in revenues related to the New Orleans Solar Station ("NOSS") that are presently reflected in Rider PPCR's rates, and which are being realigned to the EFRP. This value relates to ENO's stated $40.0 million revenue increase value as $40.0+$5.3=$45.3.

**Table 3**
**ENO's Proposed Gas Change in FRP Revenues**

| Rate Class | Applicable Base Revenue | Proposed Change in FRP Revenue | Proposed Change in FRP Revenue as Percent of Base Revenue |
|---|---|---|---|
| Residential | $ 23,524,377 | $ 12,393,492 | 52.7% |
| Small General | $ 4,766,193 | $ 2,511,003 | 52.7% |
| Large General | $ 5,497,410 | $ 2,896,235 | 52.7% |
| Small Municipal | $ 58,242 | $30,684 | 52.7% |
| Large Municipal | $ 2,378,184 | $ 1,252,913 | 52.7% |
| Total | $36,224,406 | $ 19,084,327 | 52.7% |

ENO's estimate of electric and gas typical bill impacts from its proposed FRP revenue increases are presented in Tables 4 and 5. Of note, the electric bill impacts are incremental from the FRP rate presently in effect and also reflect that approximately $5.3 million of the proposed FRP

revenue increase relates to the realignment of NOSS-related costs from Rider PPCR to the FRP, and therefore this approximate $5.3 million amount does not contribute to the bill impact.

**Table 4**
**ENO Proposed Estimated Change to Typical Electric (Legacy) Customer Monthly Bill**

| Rate Class | Typical Energy (kWh) | Typical Demand (kW) | Present | Proposed | Change |
|---|---|---|---|---|---|
| Residential[1] | 1,000 | - | $118.90 | $129.93 | $11.03 |
| Small Electric | 9,125 | 50 | $1,214.81 | $1,356.66 | $141.85 |
| Large Electric | 91,250 | 250 | $9,322.46 | $10,361.32 | $1,038.06 |

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 $120.84, proposed bills would have been $132.11, and the change would have been $11.27

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

| Rate Class | Typical Usage | Present | Proposed | Change |
|---|---|---|---|---|
| Residential | 50 ccf | $49.47 | $63.68 | $14.21 |
| Small General | 500 ccf | $408.13 | $504.57 | $96.44 |
| Large General | 1,000 mcf | $7,197.74 | $8,618.25 | $1,420.51 |

## ADVISOR REVIEW OF EVALUATION FILING

The Advisors have, during the FRPs' prescribed 75-day review period, reviewed ENO's 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 Evaluation Filing we: (i) reviewed ENO's Evaluation Filing and associated work papers; (ii) issued nine sets of discovery to ENO consisting of 140 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 Evaluation Filing focused on:

1) Validation 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., November 2021-September 2022),

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 Evaluation Filing, including tools such as Utilities International's UI Planner software, which ENO appears to have configured as its Plan to Results (P2R) regulatory filing system. Further, ENO uses licensed software such as Power Plan and Power Tax for key revenue requirement inputs.[4] As such, ENO's final compliance calculations may differ somewhat from the revenue impacts summarized in the below table.

[4] See ENO's response to DR CNO 1-4.

| Table 6<br>Summary of Advisor Adjustments and Mitigation Measures<br>($ Millions) | | | |
|---|---|---|---|
| *Description* | *Electric* | *Gas* | *Total Company* |
| **ENO Proposed FRP Revenue Increase**[1] | **$40.00** | **$18.81** | **$58.81** |
| Agreed-to Outside-the-Bandwidth Revenues | $5.17 | $0.27 | $5.44 |
| **ENO Proposed Incremental FRP Revenues** | **$ 45.17** | **$ 19.08** | **$ 64.25** |
| **Advisor Adjustments** | | | |
| ADV01 – BRAR | $(0.40) | - | $(0.40) |
| ADV02 – OPEB | $(1.50) | $(1.02) | $(2.51) |
| ADV04 – Meter Reading Expense | $(0.18) | $(0.88) | $(1.06) |
| ADV05 – Non-Typical Test Year | $(5.33) | $(2.35) | $(7.68) |
| ADV06 – FIN48 Interest | $(0.22) | $(0.02) | $(0.23) |
| ADV08 – NOPS Deferral | $(0.05) | - | $(0.05) |
| ADV09 – Storm Damage Proforma | $(0.80) | - | $(0.80) |
| ADV10 – Union PB1 Outage | $(1.49) | - | $(1.49) |
| ADV11 – Utility Conflict Survey | - | $(0.16) | $(0.16) |
| ADV12 – Regulatory Assets | $(0.22) | $(0.04) | $(0.26) |
| ADV13 – UPITA | $(0.08) | - | $(0.08) |
| **Subtotal – Advisor Adjustments** | **$(10.27)** | **$(4.47)** | **$(14.73)** |
| Total Adjusted FRP Revenue | **$34.90** | **$14.61** | **$49.52** |
| **Advisor Recommended Bill Mitigation Measures**[2] | | | |
| DOE Award | $(6.23) | - | $(6.23) |
| FERC ER13-1508 Outside Bandwidth Revenues[3] | $(5.17) | - | $(5.44) |
| FERC ER13-1508 Refund (remainder) | $(0.91) | - | $(0.91) |
| FERC EL09-61 Refund | $(2.69) | - | $(2.69) |
| Gas Bill Mitigation | - | $(1.49) | $(1.49) |
| **Subtotal – Bill Mitigation** | **$(15.00)** | **$(1.49)** | **$(16.49)** |
| **Total Adjusted and Mitigated Revenues** | **$19.90** | **$13.12** | **$33.02** |

[1] ENO's stated revenue increase does not include $5.30 million in revenues related to NOSS that are presently recovered in Rider PPCR and which are being realigned into Rider EFRP.

[2] Does not include any adjustments with respect to potential future mitigation measures such as distribution reliability (settlement in Docket UD-17-04), or load shed (settlement in Docket UD-21-01).

[3] These adjustment amounts are the result of the application of credits provided ENO in FERC Docket No. ER13-1508, Opinion No. 575.

### *Advisor Adjustments*

Here, we discuss each Advisor Adjustment regarding identified errors in the Evaluation Filing. These Advisor Adjustments are enumerated as "ADVXX" (*e.g.*, ADV01 – BRAR). Additionally, for each Advisor Adjustment, the specific adjustment dollar amount by ENO Account is detailed in Attachment C to this report.

*BRAR Revenues (ADV01)*

ENO included revenues from Rider BRAR in its presentation of Applicable Base Revenue[5] for the period April-December 2020.[6] Rider BRAR, which is structured and conceptually expected to result in a total company revenue of zero, generated $(394,813) in revenues (negative revenue) during this period. Rider EFRP's tariff language specifically excludes Rider BRAR. Further, no part of Rider BRAR provides for a true-up, and ENO is not guaranteed to generate expected revenues from riders lacking a true-up mechanism. Still further, there is no reason to expect that, prospectively, Rider BRAR will generate net revenues of any particular amount, positive or negative.[7] ENO's inclusion of revenues from Rider BRAR in its presentation of Applicable Base Revenue, is contrary to existing tariffs and prospective ratemaking principles. As such, ENO has erred in including Rider BRAR revenues in the Evaluation Filing, and Advisor Adjustment ADV01 reverses this error.

*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.[8] 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 $4.2 million. In 2020, ENO's net OPEB cost was $(4.9) 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.

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5 See EFRP Attachment A. Applicable Base Revenues apply to the calculation of revenue deficiency/(excess), with a negative contribution serving to increase ENO's requested revenue deficiency.

6 See ENO's response to DR CNO 3-1 the Excel file *TC-UD1807-02ADV003-N001*, Tab, "3-1 a", Excel Line 27.

7 *Id*.

8 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.

| Table 7<br>ENO OPEB Cost by Year<br>($ in Thousands)[1] | |
|---|---|
| **Year** | **OPEB (Income)/Cost** |
| 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 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) $1,433,619 electric and $1,012,727 gas in OPEB expense credit (i.e., negative expense) from operating expense. ENO argues this is appropriate because, although ENO's OPEB cost is negative, ENO does not receive cash or other assets from the OPEB external trust to fund the OPEB Credit.

In the 2018 Rate Case, ENO's per-book equivalent expense was $59,779 (positive expense),[9] and ENO made no proforma adjustments to that cost which is presently reflected in base rates. 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.[10] Only now does ENO propose to remove the credit from its cost of service.

ENO's proposal in the instant proceeding is not appropriate. First, this is a new ratemaking treatment not supported by the Council's precedential findings in past rate actions, including 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

[9] 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*.

[10] 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.

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.

*AMI Meter Reading Expense (ADV04)*

On October 18, 2016, ENO made its *Application of Entergy New Orleans, Inc. for Approval to Deploy Advanced Metering Infrastructure, and Request for Cost Recovery and Related Relief* ("AMI Application"). In that application, ENO preliminarily scheduled full deployment of the advanced meters by 2021.[11] The Council authorized subsequent efforts to accelerate AMI deployment, but such efforts were not fully successful due to difficulties related to the COVID-19 pandemic. [redacted]

When proposing AMI to the Council, ENO represented, "Because of the two-way data communication supported by AMI, all of the meter reading and nearly all meter services activity will be able to be performed remotely."[13] A significant portion of ENO's quantified operational benefits from AMI involved avoided meter reading services and meter services.[14] We note that ENO's AMI opt-out revenues are de minimis, which indicates that nearly all ratepayers intend to use AMI meters that do not require manual reading.

The Evaluation Filing includes proforma adjustments that reflect the completion of the AMI meter deployment. As such, and consistent with ENO's representations, no further material meter reading expenses should be incurred prospectively (consistent with the timing of ENO's proforma AMI capital adjustments).[15] However, in its Evaluation Reports, ENO proposes 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). It is not appropriate to include these proformed costs, as FERC Account 902 Meter Reading Expenses should be substantially zero in conjunction with ENO's proforma capital costs for the completion of AMI deployment. ENO has erred by not matching its proforma adjustment to capital investment in AMI with the related benefits (*i.e.*, elimination of meter reading expense). If ENO should be allowed to proform AMI capital investments sufficient to complete its AMI deployment, as it has in the Evaluation Filing, ENO should also proform related benefits, such as the elimination of meter reading expense. The Advisors have corrected ENO's error in Advisor Adjustment ADV04.

*Non-Typical Test Year (ADV05)*

ENO's proposed FRP revenue increases of $45.17 million electric and $19.08 million gas are ENO's estimate of the differences between the revenues ENO proposes that it requires to earn its

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11 See AMI Application, pg. 9.
12 See ENO's HSPM response to DR CNO 1-37.
13 AMI Application, the Direct Testimony of Dennis P. Dawsey at pg. 11
14 See AMI Application, the Direct Testimony of Jay A. Lewis, Table 1 at pg. 7.
15 In ENO's response to DR CNO 3-14.b, ENO forecasts that its 2022 Account 902 Meter Reading Expense will be $[redacted].

authorized 9.35% ROE and the revenues ENO collected in 2020.[16] The FRP tariffs capture this 2020 revenue as *Applicable Base Revenue*,[17] but for convenience and clarity, we refer to these 2020 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.*, November 2021-August 2022). If the 2020 revenues that ENO used as its Present Revenues do not reflect future base revenues, then ENO's proposed FRP rates may not be appropriate.

ENO has presented unadjusted 2020 revenues (with some months' revenues calculated as discussed above) as its Present Revenue estimates, without normalization for weather or consideration of future trends or projections of changes in sales. However, we note that the FRP 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 . . .*[18] (Emphasis added.)

As such, the FRP riders permit proforma adjustments to Present Revenues. We note that ENO has liberally employed prospective proforma adjustments to its expenses and rate base. However, as we discuss below, ENO has erred by not considering proforma adjustments to Present Revenues in the context of the COVID-19 pandemic.

<u>Effects of COVID-19</u>

COVID-19 has significantly disrupted the lives of new Orleanians and the New Orleans economy. It is broadly known and accepted that the effects of the COVID-19 pandemic adversely affected utility retail sales, in particular commercial sales that were affected by lockdowns and business closures.

The Evaluation Report is based on a 2020 Test Year. ENO's EFRP revenue adjustment is based on ENO's MWh sales to ultimate consumers of 5,449,556 in 2020, a 6.43% decrease from the previous year 2019 MWh sales of 5,823,938,[19] and a 6.72% decrease from the 5,842,129 MWh sales upon which the present base rates were calculated.[20] The Evaluation Report calculates base rate revenues of $396 million, after adjustments. The 6.43% MWh difference between 2019 and 2020, noted above, when applied to the 2020 base rate revenues of $396 million that ENO used to compute the electric FRP revenue adjustment, equates to $419 million base revenues, or a $23 million revenue difference. This suggests that if rates are set based on unadjusted 2020 revenues

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16 Specifically, revenues ENO would have earned had present rates been in effect for all of 2020. To calculate these values, for the first three months of 2020, ENO calculated the revenues it would have earned had the present rates been in effect.

17 See *AJ01A - Attachment A and G Part 1_E_WP*, Tab "PG 1_Attachment A Calculation", column e.

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

19 ENO FERC Form 1, 2020, page 301.

20 ENO's Compliance filing in Docket UD-18-07, filed 9 December 2019.

and there is any recovery of the economy and businesses in 2022 from the lows of 2020, ENO will over-collect.

Likewise for gas, ENO discussed that 2020 revenues were less than 2019:

> *The 2020 value is lower than 2019 value due to a decrease in total billed CCFs across all revenue classes as usage per customer was down across all classes in 2020 as compared to 2019.*[21]

As such, we know that ENO's electric and gas sales and base revenues declined from 2019 to 2020, and our review of available data indicates that a significant factor in these declines were the effects of the COVID-19 pandemic.

ENO has refused to provide its 2019 revenues for comparison to those of 2020, which we believe demonstrate a significant decline from 2019 to 2020 that is reasonably attributable to the effects of the COVID-19 pandemic.[22] We recommend the Council direct ENO to provide these values.

Indications of Recovery from the Effects of COVID-19

In the first six-months of 2021, the data suggest a modest recovery in ENO's revenues from 2020. ENO's electric base revenues for the twelve-month period ending June 30, 2021 were $[redacted], or $[redacted] greater than ENO's 2020 Present Revenues of $396,288,124. Further, Entergy Corp. noted that billed electric energy sales for ENO for the three months ended June 30, 2021 and 2020 showed a 2% total retail increase with a 5% residential decrease and a 10% commercial increase.[23] This shift in sales from residential to commercial and an overall increase in electric sales is consistent with a modest recovery from the effects of COVID-19.

Likewise for gas, ENO's base revenues for the twelve-month period ending June 30, 2021 were $[redacted],[24] or $[redacted] more than ENO's 2020 Present Revenues of $36,244,406.

The data indicate that a modest COVID-19-related recovery is known to be ongoing. We believe it is reasonable to expect further such recovery during the rate-effective period (*i.e.*, November 2021-August 2022 compared to 2020). We further conclude that ENO's unadjusted base revenues for 2020 are not reasonable for application in the instant FRP evaluations, based on the FRP tariff's provision for proforma revenue adjustments and ENO's extensive use of such proforma adjustments to rate base and expenses.

Advisor Adjustment

It is known that a modest recovery from the effects of COVID-19 is ongoing. The conservative measurable degree to which such a recovery is ongoing and can be expected to apply to the rate-effective period is the difference between ENO's twelve-month revenues for the periods ending June 30, 2021 and December 31, 2020, which are calculated as $4.9 million electric and $2.3 million gas.

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21 ENO's response to DR CNO 3-6.a.
22 See ENO's response to DR CNO 8-13,
23 See Entergy Corp.'s Form 10-Q filing with the SEC for the three month period ending June 30, 2021, pg. 146
24 See ENO's HSPM response to DR CNO 3-6.b. Non-Jurisdictional revenues were excluded.

Advisor Adjustment ADV05 corrects for ENO's error of using unadjusted 2020 revenues as its Present Revenues, which if uncorrected would result in unfair overcollection by ENO due to Present Revenues that do not reflect an ongoing recovery from the effects of COVID-19.

*Interest on FIN 48 Tax Liabilities (ADV06)*

In ENO's adjustment AJ06B, ENO requests recovery of $[redacted] (electric) and $[redacted] (gas) in calculated interest on tax positions that ENO is not more certain than not will be allowed by the IRS upon audit (i.e., FIN 48 tax positions).[25] ENO notes that no payments related to this amount were made.[26] 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, ENO should not be allowed to include as a proforma adjustment in its Evaluation Reports these calculated interest amounts on FIN 48 tax positions. We have corrected ENO's error regarding FIN 48 interest by reversing these electric and gas expenses through Advisor Adjustment ADV06.

*NOPS Deferral Balance (ADV08)*

During the period from NOPS's closing of capital costs to plant in service and until NOPS's revenue requirement began recovery through rates, NOPS's revenue requirement was deferred for later recovery, per Council Resolution No. R-20-344. In ENO's adjustment AJ08L, ENO proposes to collect $2,418,169, or $201,514 per month in deferral amortization.[27] However, from November 2020 (when NOPS billings began) through October 2021 (the final month before any new FRP rates will become effective), ENO has and will amortize this deferral at $2,576,500, or $214,958 per month. As such, ENO's estimate of the remaining deferral balance to amortize as of October 31, 2021 is somewhat overstated, which causes ENO's estimate of future amortization expenses recoverable in rates to also be too high. Beginning November 2021, the correct annual deferral amortization amount is $46,260 less than ENO's proposed value. Advisor Adjustment ADV08 corrects ENO's minor computational error regarding the NOPS deferral. Further, ENO should reflect this correction in future rate actions until the deferral is fully amortized.

*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., 2021 for the instant evaluation). 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.*[28]

ENO has requested a $2,740,600 proforma addition to distribution plant in service related to "storm restoration costs to be incurred in 2021 with respect to minor weather events. The budgeted

[25] See ENO's response to DR CNO 1-25, the Excel file *TC-UD1807-02ADV001-N025*.
[26] See ENO's response to DR CNO 7-3.
[27] See ENO Adjustment AJ08L, the Excel file, *AJ08L - NOPS Revenue Requirement_E*, Tab, AJ08L.3.
[28] Rider Schedule EFRP-6, FN 1 at pg. 30.3

amount is based on historical experience."[29] However, "ENO cannot identify the storms related to this projected capital expenditure."[30] ENO errs in proposing this proforma adjustment because historical average costs do not constitute a capital budget item for the purposes of FRP "known and measurable" adjustments, as we discuss below.

The likelihood of minor storms occurring sometime in 2021 does not constitute a related known and measurable cost.[31] It is known as a general matter that every utility plant item is subject to potential storm damage at some point and may then require replacement. However, knowing that something generally has happened in the past and may occur in the future is not the same as "expected to be incurred" as the Rider states. In our opinion, "expected to be incurred" more reasonably refers to investment projects ENO has authorized and reasonably expects to be closed to plant in service during the proforma period (i.e., 2021). ENO's adjustment here is more of a historical averaging reflecting its general sense of ad-hoc capital expenditures that may happen.

As such, ENO erred in proposing the proforma adjustment to add $2,740,600 to its plant in service. Advisor Adjustment ADV09 corrects this error by removing this proforma and its related ratemaking effects. We note that this Advisor Adjustment does not prevent ENO from the reasonable opportunity to recover all of its costs related to actual storm capital investments it may make.

*Deferral of Proforma O&M Costs (ADV10 and ADV11)*

In our opinion, the intent of allowing ENO to propose proforma O&M costs in the Evaluation Filing is to match the timing of costs to the rate-effective period consistent with the regulatory principle of prospective ratemaking. ENO has erred in the Evaluation Filing by using a combination of proforma O&M costs and cost deferral that act together to accelerate deferrals and carrying costs. In our opinion, the regulatory principle of prospective ratemaking is better achieved by allowing ENO to propose deferral of O&M costs from the test year.

We have identified instances in the Evaluation Filing where ENO has proformed O&M costs that it expects to occur in the year following the test year (i.e., in 2021) and then deferred such proformed costs as a regulatory asset for recovery over multiple years. Advisor Adjustments ADV10 and ADV11 have reversed the instances we identified where ENO erred by deferring a proforma O&M cost. We note that these Advisor Adjustments, reversing ENO's proposed deferral of proformed costs, still allow ENO full recovery of such costs, as they can still be deferred for recovery in an FRP whose test year encompasses the costs to be deferred (in this case, the 2021 test year FRP evaluation to be filed in 2022). We discuss each adjustment below.

<u>Union PB1 Outage Cost Deferral (ADV10)</u>

In proforma AJ08P, ENO proposes to defer over three years $3,911,566 in proforma (i.e., expected to be accomplished in 2021) O&M related to a maintenance outage at the Union PB1 generating unit. As we discuss above, ENO has erred in its proposed proforma adjustment AJ08P, and we have reversed this error in Advisor Adjustment ADV10.

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29 ENO's response to DR CNO 1-38

30 *Id*.

31 We note that Hurricane Ida caused significant damage to ENO's electric utility after the filing of the Evaluation Report, and costs related to that event are expected to be addressed outside of the instant FRP evaluation.

Gas Utility Conflict Survey (ADV11)

In proforma AJ08M, ENO proposes to increase its gas rate base by $1,754,817 and deferred tax by $457,623. ENO's AJ08M does not appear to propose to increase ADIT by this amount of deferred tax. These increases to rate base and deferred tax relate to ENO's proforma of a total of $6 million in in Gas Utility Conflict Survey costs as of December 31, 2021 compared to $4,245,183 per book as of December 31, 2020.

As we discuss above, ENO has erred in its proposed proforma adjustment AJ08M, and Advisor adjustment ADV11 corrects this error by reversing ENO's $1,754,817 increase to rate base and the related $457,623 in deferred tax. As AJ08M does not proform any ADIT related to its proforma deferred tax, it is not necessary to adjust ADIT as part of ADV11. We note that, Advisor Adjustment ADV11 does not modify ENO's proposed $2.0 million amortization expense recovery. Per Council Resolution Nos. R-19-457 and R-20-67, ENO is allowed to defer prudently-incurred per book O&M related to the gas utility conflict survey for amortization over the ordered 10-year period at a rate of $2.0 million per year.

*Regulatory Asset Proformas (ADV12)*

Throughout ENO's Evaluation Filing, ENO has proformed rate base items forward by twelve months from a December 31, 2020 value to a December 31, 2021 value. These proforma adjustments are allowed by the FRP Riders, and they are consistent with the prospective ratemaking principle. This same principle applies to regulatory assets that ENO will amortize during the rate-effective period. We identified two such regulatory assets whose balances should be proformed forward by twelve months at their amortization rate and where ENO erred by not doing so.

Algiers Customer Migration Regulatory Asset

As of December 31, 2020, ENO recorded $3,866,259 as a regulatory asset (electric) related to its costs of Algiers Customer Migration.[32] The Evaluation Filing's rate base component of this regulatory asset is $2,857,939, also as of December 31, 2020.[33] This rate base amount should be credited (*i.e.*, reduced) by $797,564 to reflect twelve months of amortization, which we have done in Advisor Adjustment ADV12.

2018 Rate Case Expense Regulatory Asset

As of December 31, 2020, ENO recorded $4,631,064 electric and $1,086,299 gas as regulatory assets related to the 2018 Rate Case.[34] These regulatory assets should be credited (*i.e.*, reduced) to reflect twelve months of amortization, which we have done in Advisor Adjustment ADV12.

*UPITA (ADV13)*

Related to the Tax Cuts and Jobs Act of 2017, ENO recorded Unprotected Excess ADIT ("UPITA") liabilities. As of June 31, 2021, an uncommitted balance of $853,889 remains in ENO Account 254218.[35] UPITA is properly reflected as a credit to rate base, and ENO erred in not

[32] See *RB12.1*, line 13.
[33] See ENO's response to DR CNO 8-12.b.
[34] See *RB12.1*, line 14.
[35] See ENO's response to DR CNO 8-15.b.

including this amount in the Evaluation Filing's rate base. Advisor Adjustment ADV13 corrects ENO's error by crediting rate base by this amount.

### ***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%.

Three potential sources of mitigation that are available with respect to Electric customers are monies currently being held by ENO pending Council direction. These monies could be utilized at the Council's discretion to reduce the magnitude of the FRP Rate Adjustment beyond the errors that are ultimately identified and agreed to by the Parties.

*FERC Docket ER13-1508 Refund*

In FERC Docket No. ER13-1508 *et al.*, Opinion No. 575, FERC directed Entergy to calculate refunds related to the allowed ROE of certain Purchase Power Agreements ("PPA") having ENO as a purchaser (as such, relating to ENO's electric utility). The refund amounts paid to ENO on or about July 19, 2021 totaled $6,072,133. On August 20, 2021, Committee Chair Moreno asked ENO to hold this refund until the Council provided guidance as to how the refund shall be utilized.[36]

Per an Agreement in Principle ("AIP") as of September 28, 2020 and approved by the Council in Resolution No. R-20-344, ENO is entitled to collect in the instant FRP Evaluation's rates a total of $5,165,113 in electric revenues and $273,298 in gas revenues outside the FRP's bandwidth mechanism. ENO correctly notes that the rate-effective period of the instant FRP Evaluation is ten months, which complicates the Company's ability to have the reasonable opportunity to collect these revenue requirements through a simple FRP rate adjustment. This is because an annual rate applied over ten months likely will not generate the full revenue requirement.

ENO has proposed a true-up mechanism to ensure the full collection of its allowed outside-the-bandwidth revenue requirement.[37] However, ENO is not entitled to exact cost recovery through the FRP, and according to the FRP Riders' design, ENO's revenues from the FRP Riders may be higher or lower than its revenue requirement. As such, neither the FRP Riders' tariff language nor customary ratemaking principles support a FRP revenue true-up mechanism. Any such true-up mechanism would require Council approval, and such a review and approval process is not provided for in the FRPs' tariff or the instant FRP Evaluation process.

Rather than introduce a novel ratemaking mechanism to the FRP, we recommend using the FERC Docket No. ER13-1508 refund proceeds to satisfy ENO's agreed-to $5,165,113 of electric outside-the-bandwidth revenues. We recommend that Council direct ENO to apply $5,165,113 of this refund amount to eliminate the need to collect these outside-the-bandwidth revenues through the FRP's rate. Further, we recommend that the Council direct ENO to apply the remaining $907,020 be applied in ten equal increments as a credit to the Fuel Adjustment Charge, November 2021 through August 2022. The mitigation impacts of this refund credit are shown in Table 6 in the line

[36] See letter *Re: Federal Energy Regulatory Commission Docket Nos. ER13-1508, et al.*, August 20, 2021.
[37] See Summary, Sections XVIII-XIX at pp. 12-13.

items "FERC ER13-1508 Outside Bandwidth Revenues" and "FERC ER13-1508 Refund (remainder)."

Regarding the $273,298 in gas outside-the-bandwidth revenue amount, this electric FERC refund credit is not customarily applicable to gas revenue requirements. We recommend that ENO may either proceed with this revenue amount in the instant FRP evaluation and risk not fully recovering its amount over ten months, or ENO may elect to include this amount in the next FRP evaluation (to be filed by April 30, 2022), when a twelve-month rate-effective period would apply. Our revenue and bill impact calculations in this report assume ENO will elect to defer this revenue amount until the 2022 FRP filing, as doing so would be more advantageous to ENO than a partial recovery over ten months in the instant proceeding.

*2020 DOE Refund Credit*

In Late 2020 System Energy Resources, Inc. was awarded approximately $40.5 million from the DOE for interim spent fuel damages from 2012-2017. ENO's share of the award is approximately $6.2 million.

As with the FERC refund credit's disposition, due to the instant FRP Evaluation's ten-month rate-effective period, we do not recommend that this DOE award credit be applied directly to the FRP adjustment. Rather, we propose that the Council direct ENO to apply the DOE award credit provided to ENO ratepayers as ten equal credits to the FAC, November 2021-August 2022. The impact of this mitigation is shown in table 6 in the line item "DOE Award."

*FERC Docket No. EL09-61 Refund Balance*

In FERC Docket No. EL09-61, ENO received an approximate $7 million refund related to EAL's off-system sales practices.[38] For the purpose of assisting residential ENO customers who were experiencing difficulty in paying their utility bills due to COVID-19 dislocations, Council Resolution No. R-20-146 applied this approximately $7 million refund to fund the CCC program. On September 29, 2021, at the conclusion of the preparation of this report, ENO filed its *Final Report Pursuant to Council Resolutions R-20-146 and R-20-380 on the City Council Cares Act* with the Council, which states that the program's End Balance as of August 1, 2021, consisting of unapplied 2018 FERC Off-System Sales Refund credits, is $2,691,055. With the available time to review and validate this value, we see no reason why this ending amount should not be employed by the Council to mitigate customer bills. We propose that the Council direct ENO to apply the ending balance to ENO ratepayers as ten equal credits to the FAC, November 2021-August 2022. The impact of this mitigation is shown in Table 6 in the line item "FERC EL09-61 Refund."

*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

[38] See FERC Docket No. EL09-61-008, Opinion No. 565.

the nine-to-ten subsequent years.[39] Such investments through 2019 were authorized by the Council in Resolution No. R-17-38.

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.[40] ENO has not finalized its GIRP program timeline, but now expects GIRP to end in 2032.[41]

The Advisors have on multiple occasions expressed concern for 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.[42] ENO has never developed a plan for the pace of GIRP investment that only takes into account public safety, as demonstrated by ENO's response to discovery in the instant proceeding:

> *Q: Has ENO prepared a GIRP schedule of miles installed per year that only takes into account public safety (i.e., the only consideration was the minimum miles installed per year that prudently would provide for the public safety)? If the answer is in the affirmative, please provide the most current copy of such.*
>
> *A: ENO has prepared a GIRP schedule that maintains safety as a priority while balancing customer needs, minimizing rate effects to customer bills, and maintains compliance with applicable pipeline safety regulations.*[43]

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.[44] As such, ENO proposes modifying its existing GIRP program timeline starting with 2023.[45] We recommend that the Council direct ENO to prepare a schedule of investment in gas distribution pipe starting with 2023 that constitutes the least ratepayer bill impact (which is distinct from the least overall revenue requirement impact), while providing for adequate public safety.

The instant evaluation's GFRP rates reflect GIRP investments that ENO has already made or expects to complete by December 31, 2021. As such, prospective changes to GIRP's investment schedule cannot mitigate ENO's present proposed GFRP rate of 52.7%.

*Depreciation Schedule*

ENO's Gas Infrastructure Replacement Project primarily employs High Density Polyethylene ("HDPE") pipe, which ENO refers to as "plastic".[46] ENO presently applies a 3.33% depreciation rate,[47] 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.[48] While

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39 See *New Orleans Gas System Infrastructure Replacement Update*, October 27, 2016, slide 9.
40 See *GIRP Working Group – Gas Ops – v5 draft, February 19, 2020*, slide 4.
41 See ENO's response to DR CNO 2-8.
42 See Docket No. UD-18-07, Exhibit BSW-5.
43 DR CNO 2-4 and ENO's response thereto.
44 See ENO's response to DR CNO 2-8.
45 See *Id.*
46 376.3 Mains-Plastic. See ENO's response to DR CN) 2-6.a.
47 Evaluation, Excel file, AJ08J - Depreciation_G, Tab "AJ08J.2", Row 25, the column "Depr Rate".
48 See Council Resolution No. R-17-38, Ordering Paragraph 2.

approving the 3.33% depreciation rate for HDPE pipe in Resolution No. R-19-457, the Council directed ENO, the Advisors, and Intervenors to explore bill mitigating measures.[49]

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 November 1, 2021 (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 short. The only depreciation schedule for this type of pipe in ENO's possession is that of ELL.[50] However, 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."[51] As such, while the Council had directed a 40-year depreciation schedule for GIRP, and a return to this rate is recommended, 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 direct ENO to study and report to the Council why a 55-70-year depreciation schedule is not prudently applicable to plant recorded in FERC Account 376.2 – Mains Plastic (the account where HDPE pipe's original cost is recorded).

*Utility Conflict Survey Amortization Period*

In the 2018 Rate Case, ENO proposed, and the Council authorized a $20 million utility conflict survey,[52] but the Council did not explicitly direct a recovery period. ENO had proposed a 10-year recovery period, which the Council did not deny.[53] The instant GFRP Evaluation is the first rate action in which the utility conflict survey's costs are proposed to be recovered.

Given ENO's proposed GFRP rate (52.74%), the Council should direct ENO to mitigate the bill impact related to the utility conflict survey by amortizing its cost over 20 years.

The impact of these gas bill mitigation adjustments, specifically HDPE pipe depreciation and the utility conflict survey's amortization period, is shown in Table 6 in the line item "Gas Bill Mitigation."

### *Cost Allocation/Customer Class Decoupling Adjustments*

While the methods of cost allocation used in the General Rate case are to be maintained throughout the EFRP filings, updating external allocation factors with current billing determinants is necessary to maintain fairness in the customer class decoupling revenue adjustments. Certain methods of cost allocation were addressed in Resolution No. R-19-457, while the treatment of other cost allocation methods, such as the capacity cost allocation related to interruptible loads, while not

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

50 See ENO's response to DR CNO 2-6.d.

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

52 See Council Resolution No. R-19-457, Ordering Paragraph 2.d.

53 See Council Resolution No. R-19-457, Ordering Paragraph 42: "To the extent not otherwise modified in this Resolution, ENO's remaining proposals are approved as filed by ENO."

specifically addressed, were included within the Council's directives in Resolution R-19-457 related to the allocation of customer class revenue requirements.

Directive 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 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.

Directive 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 for the electric and gas utilities respectively.

Also, Rider EFRP Tariff Sec. II.B.2 states that the determination of the fixed and variable revenue requirements by rate class shall be consistent with the allocation methodologies approved in Docket UD-18-07 except that the return on rate base component shall be based on class rates of return corresponding to the relative rate class revenues set in Docket UD-18-07.

Importantly, the Council's directives in Resolution R-19-457 did not specifically address or approve the allocation of capacity costs to interruptible load, but Directive 14 did specify that the revenue requirements will be recovered from each customer class on the basis of the proposed customer class revenue requirements as indicated in Advisors' Exhibit VP-20. Specifically for the interruptible load LIS customer, Advisors' Exhibit VP-20 showed a $7.67 million cost of service based on an 18.50% rate of return on rate base including taxes (see Attachment A). In comparison, ENO's Compliance Filing pursuant to Resolution R-19-457 similarly showed a $7.6 million cost of service but based on a 57.57% rate of return on rate base including taxes. In other words, to comply with the Council's Directive setting revenue requirement by customer class, the difference in the allocated capacity cost responsibility between ENO and the Advisors resulted in ENO's allocated cost of service showing a much larger rate of return for the LIS rate for the same LIS revenue requirement. Of the total LIS load of approximately 20MW, 15 MW is interruptible load; and to that significant interruptible load portion, ENO attributes a capacity cost responsibility of 15% of that assigned to firm MW. In contrast, the Advisors attributed an interruptible load capacity cost responsibility of 52% of that assigned to firm MW, based on a study of interruptible services ordered by the Minnesota PUC.[54] Since the revenue decoupling adjustment is based on the customer class revenue requirements established in Resolution R-19-457, and not on the class rates

[54] Based on "A Study Of Interruptible Services at XCEL Energy"" - November 1, 2010 prepared by Christensen Associates Energy Consulting, LLC in collaboration with staff in several departments of Xcel Energy. Additionally, it draws on a summary by Xcel Energy of work performed by PA Consulting Group, Inc. The study fulfills a compliance order issued by the Minnesota Public Utilities Commission in October 2009."

of return, the Advisors recommend that ENO adopt the interruptible load capacity cost responsibility used in Exhibit VP-20, as referenced in directive 14 of Resolution R-19-457.

ENO's Evaluation was consistent with its Compliance Filing, with respect to applying the structure of Advisors' Exhibit VP-20 in proposing the allocated customer class revenue requirements related to the EFRP decoupling adjustment. As noted previously, Directive 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 adjusted the rate of return to the Residential class, without any adjustments to any of the other customer classes. The LIS rate of return on rate base in ENO's EFRP Evaluation decoupling proposal was relatively unchanged from ENO's Compliance Filing. 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 LIS rate of return was lowered, and the Residential rate of return was adjusted slightly toward ENO's total utility rate of return, such that both Residential and LIS have proposed comparable total revenue increases as shown in Attachment B.

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 exceeds 10% of base revenue (see Table 2) that decoupling revenue adjustment cap is not applicable to the instant EFRP Evaluation. In any case, the Advisors' Evaluation decoupling revenue adjustment percentages were less than those proposed in ENO's EFRP Evaluation for all customer classes.

### 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 Evaluation Filing, but does not reflect our recommended bill mitigation measures. Table 2, which presents ENO's proposed change in FRP revenue is reproduced for comparison.

| Table 2<br>(reproduced from above)<br>ENO's Proposed 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 | $ 176,876,728 | $ 24,218,599 | 13.7% |
| Small Electric Service | $ 66,333,601 | $ 10,230,103 | 15.4% |
| Municipal Buildings | $ 1,994,937 | $ 289,852 | 14.5% |
| Large Electric | $ 26,984,373 | $ 4,058,662 | 15.0% |
| Large Electric High Load Factor | $ 92,536,682 | $ 4,449,625 | 4.8% |
| Master Metered Non-Residential | $ 209,176 | $ 75,231 | 36.0% |
| High Voltage | $ 5,525,819 | $ 234,227 | 4.2% |
| Large Interruptible | $ 3,946,033 | $ 1,223,272 | 31.0% |
| Lighting Service | $ 4,187,282 | $ 521,864 | 12.5% |
| Total | $ 378,594,630 | $ 45,301,435 | 12.0% |

| Table 8<br>Advisor Adjusted Electric Change in FRP Revenues | | | |
|---|---|---|---|
| Rate Class | Applicable Base Revenue | Advisor Adjusted Change in FRP Revenue | Adjusted Change in FRP Revenue as Percent of Applicable Base Revenue |
| Residential | $176,876,728 | $21,376,232 | 12.1% |
| Small Electric Service | $66,333,601 | $9,298,335 | 14.0% |
| Municipal Buildings | $1,994,937 | $126,242 | 6.3% |
| Large Electric | $26,984,373 | $1,600,555 | 5.9% |
| Large Electric High Load Factor | $92,536,682 | $1,436,146 | 1.6% |
| Master Metered Non-Residential | $209,176 | $47,403 | 22.7% |
| High Voltage | $5,525,819 | $86,433 | 1.6% |
| Large Interruptible | $3,946,033 | $608,943 | 15.4% |
| Lighting Service | $4,187,282 | $442,135 | 10.6% |
| Total | $378,594,630 | $35,022,425 | 9.3% |

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

| Table 3<br>(reproduced from above)<br>ENO's Proposed Gas Change in FRP Revenues | | | |
|---|---|---|---|
| Rate Class | Applicable Base Revenue | Proposed Change in FRP Revenue | Proposed Change in FRP Revenue as Percent of Base Revenue |
| Residential | $ 23,524,377 | $ 12,393,492 | 52.7% |
| Small General | $ 4,766,193 | $ 2,511,003 | 52.7% |
| Large General | $ 5,497,410 | $ 2,896,235 | 52.7% |
| Small Municipal | $ 58,242 | $30,684 | 52.7% |
| Large Municipal | $ 2,378,184 | $ 1,252,913 | 52.7% |
| Total | $36,224,406 | $ 19,084,327 | 52.7% |

| Table 9<br>Advisor Adjusted Gas Change in FRP Revenues | | | |
|---|---|---|---|
| Rate Class | Applicable Base Revenue | Advisor Adjusted Change in FRP Revenue | Adjusted Change in FRP Revenue as Percent of Applicable Base Revenue |
| Residential | $23,524,377 | $9,510,652 | 40.4% |
| Small General | $4,766,193 | $1,926,920 | 40.4% |
| Large General | $5,497,410 | $2,222,544 | 40.4% |
| Small Municipal | $58,242 | $23,547 | 40.4% |
| Large Municipal | $2,378,184 | $961,474 | 40.4% |
| Total | $36,224,406 | $14,645,136 | 40.4% |

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

| Table 10<br>Estimated Change to<br>Typical Electric (Legacy) Customer Monthly Bill | | | | | |
|---|---|---|---|---|---|
| Rate Class | Energy (kWh) | Present | ENO Proposed | After Advisor Adjustments and Bill Mitigation Measures | Change from ENO Proposed |
| Residential | 1,000 | $118.90 | $129.93 | $125.30 | $(4.63) |
| Small Electric | 9,125 | $1,214.81 | $1,356.66 | $1,316.79 | $(39.87) |
| Large Electric | 91,250 | $9,322.46 | $10,361.32 | $9,357.57 | $(1,003.75) |

The typical bill effects on 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 below table presents the gas typical bill impact effect of the Advisor Adjustments and bill mitigation measures.

| **Table 11<br>Estimated Change to<br>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 | $49.47 | $63.68 | $59.06 | $(4.62) |
| Small General | 500 ccf | $408.13 | $504.57 | $473.22 | $(31.35) |
| Large General | 1,000 mcf | $7,197.74 | $8,618.25 | $8,156.59 | $(461.66) |

## OTHER MATTERS FOR COUNCIL CONSIDERATION

### *Pension Rate Base Debit*

The Advisors have reviewed ENO's proposed ratemaking related to its qualified pension plan, which includes a rate base debit (*i.e.*, increase to ENO's rate base and revenue requirement) related to a formula that increases the debit with Employer Contributions to the trust fund. While ENO's proposed ratemaking related to such is consistent with its proposal in the 2018 Rate Case, subsequent to that proceeding, FERC issued its Opinion No. 570, which has shed light on pension-related matters suitable for Council consideration. Opinion No. 570 casts doubt on (1), whether ENO's calculation of its rate base debit accurately reflects the agreed-to regulatory principle for prepayments includable in rate base, and (2), whether all ENO contributions to its pension's external trust account provide benefits in excess of related costs to ratepayers.

Regarding the first issue, ENO has stated the principle succinctly,

> *[t]he basis for the Prepaid Pension Asset is the difference between what has been contributed to the trust accounts and the amount that has been included in pension expense.*[55]

ENO's position is consistent with the regulatory principle that, generally, long-term prepayments by ENO without corresponding expense recognition are includable in rate base. In Opinion No. 570, FERC concluded the same,

> *We* [the FERC Commissioners] *find that Entergy has not demonstrated that its proposed formula for calculating prepaid pension costs is just and reasonable. As explained above, a prepaid pension cost is the amount by which cumulative*

[55] Docket No. UD-18-07, Rejoinder Testimony of Joshua Thomas, at pg. 20. Reiterated in ENO's response to DR CNO 1-30.

> *contributions to a pension trust exceed cumulative pension expense. Consistent with this definition,* ***the appropriate way to calculate prepaid pension costs includable in rate base would be to calculate the cumulative differences between each year's pension contributions made by Entergy and pension expenses.*** *Entergy proposes to use a different formula (i.e., Funded Status minus Unrecognized Gains and Losses). Although Entergy asserts that this formula leads to the same end result, we find that Entergy has not adequately supported this claim.*
>
> . . .
>
> *Furthermore, Entergy does not explain why using the Funded Status is an appropriate methodology to calculate prepaid pension costs in rate base. Entergy explains that Funded Status equals Fair Value of Plan Assets minus Projected Benefit Obligation, but Entergy does not explain why using Funded Status and Unrecognized Gains/Losses yields the same result as calculating cumulative employer contributions and cumulative pension expense. In some instances, it may be inappropriate to use Funded Status for calculating prepaid pension costs. For example, Entergy's actuarial disclosure includes a line item for employee contributions for the calculation of Fair Value of Plan Assets, which is a component of Funded Status. However,* ***employee contributions to a pension trust are not shareholder financed funds that the utility has paid out of pocket. Consequently, it would not be just and reasonable for Entergy to include amounts that employees contribute to pension plans in rate base and earn a return on such amounts****.*[56](Emphases added.)

We note that our review of discovery responses in the instant proceeding does not indicate any recent employee contributions to ENO's qualified pension plan.[57] However, ENO's methodology in the instant proceeding would improperly include any such employee contributions in its rate base debit.

We concur with FERC that the correct way to calculate any amount includable in rate base is to subtract cumulative pension expenses from employer pension contributions. As with ENO and the other EOCs[58] in FERC Docket No. ER15-1436 (the docket from which Opinion No. 570 arises), ENO refused to perform this calculation.[59] It is not possible to determine if ENO's estimation method in the instant proceeding complies with the above agreed-to methodology, as also noted by the FERC Trial Staff in FERC Docket No. ER15-1436. As such, we recommend the Council direct ENO to calculate a prepaid pension value includable in rate base based on the cumulative difference between each year's pension contributions made by ENO and pension expenses.[60] We have examined all available Entergy's SEC 10k filings relative to ENO pension contributions and pension costs for the past 28 years (1993 to 2020), and using the definition of prepaid pension costs includable in rate base as the cumulative difference between pension contributions and

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[56] FERC Opinion No. 570, pp. 56-58

[57] See ENO's HSPM response to DR CNO 4-7.

[58] The Entergy Operating Companies ("EOCs") are EAL, Entergy Louisiana, LLC, Entergy Mississippi, LLC, ENO, and Entergy Texas, Inc.

[59] See ENO's response to DR CNO 1-29.a. wherein ENO refused to perform this calculation for the period 2000-2020.

[60] To the extent such records no longer exist prior to a certain date, we recommend the Advisors work with ENO to establish a reasonable estimate as of that date as a starting point for this calculation.

pension expenses, determined a present value of $20 million electric and $4.4 million gas for inclusion in rate base, versus $35.4 million electric and $7.7 million gas proposed by ENO. These differences represent a total electric and gas revenue requirement difference of $1.6 million.

Regarding the second issue cited above, once a calculation as to a pension amount includable in rate base is performed, this amount should be scrutinized as to whether it is useful to ratepayers at least commensurate with its cost to ratepayers. The Advisors recommend the Council direct ENO to provide historical data required to validate ENO's proposed pension rate base debit calculation methodology. These data can be used to evaluate whether ENO's Employer Contributions are reasonable and useful to ratepayers. Table 12 presents certain historical data for ENO's qualified pension plan that is a subset of the data ENO should provide to allow for a complete evaluation.

**Table 12**
**ENO Qualified Pension - Key Data by Year[1]**
**('000' Dollars)**

| | [A] | [B] | [C] | [D] | [E] | [F] = [D] + [E] | [G] | [H] = [F] + [G] |
|---|---|---|---|---|---|---|---|---|
| **Year** | **Net Pension Cost** | **Employer Contribution** | **Benefits Paid** | **PBO at Year End** | **Fair Value of Assets at Year End** | **Funded Status at Year End** | **Regulatory Asset at Year End[2]** | **ENO's Proposed Rate Base Debit** |
| 1992-2005 | 41,963 | 32,458 | 21,357 | (88,749) | 44,684 | (44,065) | 23,297 | (20,768) |
| 2006 | 5,857 | - | 3,864 | (85,970) | 46,298 | (39,672) | 23,003 | (16,669) |
| 2007 | 2,781 | 43,585 | 4,087 | (89,132) | 90,692 | 1,560 | 22,574 | 24,134 |
| 2008 | 1,569 | - | 5,418 | (89,315) | 60,104 | (29,211) | 51,776 | 22,565 |
| 2009 | 1,749 | 1,107 | 4,569 | (101,325) | 72,046 | (29,279) | 51,202 | 21,923 |
| 2010 | 3,588 | 12,957 | 5,162 | (128,477) | 88,688 | (39,789) | 71,080 | 31,291 |
| 2011 | 5,538 | 12,160 | 5,498 | (151,966) | 94,202 | (57,764) | 95,677 | 37,913 |
| 2012 | 8,457 | 5,811 | 5,813 | (174,585) | 106,778 | (67,807) | 103,074 | 35,267 |
| 2013 | 10,413 | 4,175 | 6,252 | (163,707) | 122,960 | (40,747) | 69,856 | 29,109 |
| 2014 | 6,607 | 10,509 | 7,113 | (202,555) | 133,344 | (69,211) | 102,141 | 32,930 |
| 2015 | 8,981 | 10,903 | 11,029 | (191,064) | 129,975 | (61,089) | 95,941 | 34,852 |
| 2016 | 5,593 | 10,709 | 9,054 | (197,464) | 142,488 | (54,976) | 94,944 | 39,968 |
| 2017 | 5,096 | 9,893 | 8,738 | (217,896) | 165,747 | (52,149) | 96,913 | 44,764 |
| 2018 | 5,789 | 7,250 | 17,808 | (191,190) | 145,968 | (45,222) | 91,448 | 46,226 |
| 2019 | 5,101 | 4,553 | 18,296 | (206,962) | 160,777 | (46,185) | 91,862 | 45,677 |
| 2020 | 5,988 | 4,567 | 15,689 | (220,287) | 172,551 | (47,736) | 91,991 | 44,255 |
| **Total** | **125,070** | **170,637** | **149,747** | | | | | |

[1] Source: Entergy Corp.'s Form 10-K reports to the SEC, *e.g.*, for 2020, see pp. 165 and 169.
[2] Value reflects the program's PBO less accumulated annual Pension Costs.

We note ENO's unusually high $43.6 million Employer Contribution in 2007, which happens to be a test year in the 2008 rate case. We further note the years in which ENO's contributions were much smaller than average, or even zero. The data are suggestive of a wide range of discretion as to ENO's Employer Contributions. Over the period 1992-2005, the period for which data are reasonably available without accessing specially archived files, ENO's Employer Contributions have not exceeded Net Pension Cost, although trust assets exceeded the Benefits Paid.

ENO refused to disclose how much of these Employer Contributions were above a mandatory minimum, except for the years 2018-2020.[61] Over this three year period, Employer Contributions totaled $16,370,139, which is $3,943,013 greater than ENO's stated Minimum Required Contribution totaling $12,427,126.[62] However, during two of these three years, ENO contributed less than what ENO characterizes as the minimum required contribution, and ENO made no contributions in 2006 and 2008, which casts doubt as to the actual minimum contribution ENO must make. As such, ENO's interpretation of the Advisors' requested "minimum required contribution" requires clarification.

The above table's arithmetic functions demonstrate that Employer Contributions directly increase the Fair Value of Assets in the trust, which in turn directly increase ENO's proposed rate base debit. By operation of ENO's proposed pension rate base debit formulae, ENO Employer Contributions to the trust result in a return to ENO's shareholders of ENO's before-tax Weighted Average Cost of Capital ("WACC"), presently 8.57%. However, ENO's present expected long-term rate of return on its qualified pension assets is 6.75%.[63] As ENO's contributions to the trust are merely deposits to fund future obligations, the benefit to ratepayers of such contributions is presently 6.75%, because the return on such contributions reduces future ratepayer costs to provide defined benefits,[64] and ratepayers are paying ENO 8.57% for having made these deposits. ENO's shareholders[65] profit by the difference between these rates (8.57%-6.75%=1.82%) with no benefit to ratepayers. As such, it is not appropriate for ENO's shareholders to earn a return greater than the trust's expected long-term rate of return on contributions in excess of mandated minimums.

As contributions to the trust have a benefit to ratepayers of a 6.75% annual rate of return, ENO should not be allowed a return greater than this rate on discretionary contributions to the trust. While the Advisors requested the amount of ENO's historical required trust contributions, ENO has refused to provide the requested information, and the very limited information ENO has provided is not internally consistent.

We recommend the Council direct ENO to provide this information with a detailed explanation of how ENO determined each year's mandated minimum contribution amount.

We further recommend the Council to consider whether it is appropriate for ENO to contribute to the pension trust in excess of mandated minimum amounts or alternately, why such discretionary contributions should be allowed a return in ENO's rate base at its WACC if that WACC is greater than the rate of benefit ratepayers would enjoy from such discretionary contributions. To indicate the potential magnitude of improper returns on discretionary contributions, consider ENO's 1992-2020 Employer Contribution total of $170,637 million. If, for the sake of illustration, all of these contributions were discretionary, at present annual rates, ENO is earning $3.1 million annually in excess of ratepayer benefit.

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61 See ENO's response to DR CNO 1-29.

62 *Id.*

63 See ENO's 2020 SEC 10-K report, pg. 33.

64 See ENO's response to DR CNO 1-29: "The prefunding balance is credited with interest equal to the trust fund's actual asset returns and is available to cover subsequent years' contribution requirements."

65 ENO is an LLC with membership interests, not shareholders. However, Entergy Corp., ENO's ultimate beneficial owner, is a C-corporation with shareholders. As such, for convenience, we refer to ENO's shareholders generally as those with ultimate beneficial ownership.

**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 B**
**FRP Revenue Change**
**Calculation by Rate Class**

| | 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 | (7,343,155) | 1,120,718,286 | 645,678,853 | 161,199,135 | 4,746,511 | 67,888,810 | 209,498,217 | 561,688 | 9,987,593 | 8,465,137 | 12,692,342 |
| ENO Required Rate Of Return On Rate Base Including Taxes | | 8.57% | 2.3% | 18.3% | 20.2% | 14.7% | 16.9% | 15.5% | 13.0% | 13.2% | 20.2% |
| Return On Rate Base Including Income Taxes | (629,125) | 96,017,539 | 15,049,782 | 29,531,681 | 959,313 | 10,005,173 | 35,405,234 | 86,975 | 1,302,965 | 1,117,736 | 2,558,776 |
| O&M Expense | (3,015,885) | 392,721,848 | 210,666,811 | 54,184,863 | 1,492,853 | 25,120,987 | 84,815,263 | 209,233 | 7,276,844 | 6,716,709 | 2,238,285 |
| Gains From Disposition Of Allowances | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Regulatory Debits & Credits | 0 | 5,025,340 | 2,920,547 | 738,260 | 21,339 | 300,164 | 919,712 | 2,547 | 36,223 | 22,832 | 63,716 |
| Interest On Customer Deposits | 0 | 757,290 | 437,756 | 109,154 | 3,211 | 45,938 | 141,752 | 380 | 6,777 | 3,767 | 8,555 |
| Other Credit Fees | (215,572) | 46,894 | 27,107 | 6,759 | 199 | 2,845 | 8,778 | 24 | 420 | 233 | 530 |
| Depreciation & Amortization Expense | (594,643) | 63,230,014 | 37,367,622 | 9,062,528 | 267,028 | 3,635,672 | 11,226,086 | 29,153 | 528,753 | 418,044 | 695,129 |
| Amortization Of Plant Acquisition Adjustment | 0 | 1,189,690 | 652,209 | 164,261 | 4,566 | 78,010 | 247,010 | 628 | 22,657 | 16,196 | 4,154 |
| Taxes Other Than Income | (1,315) | 20,049,544 | 11,796,378 | 2,891,854 | 82,308 | 1,165,438 | 3,613,734 | 9,655 | 180,053 | 107,725 | 202,400 |
| ENO ADJUSTMENT FOR TAX DIFFERENCE (memo) | | (1,232,503) | (504,965) | (273,284) | (7,464) | (101,553) | (324,220) | (800) | (15,942) | 13,359 | (17,635) |
| 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 | 44,053,656 | 19,854,555 | 6,227,991 | 178,711 | 3,197,420 | 11,931,571 | 27,971 | 1,024,688 | 1,232,300 | 378,450 |
| Total Cost Of Service | (4,456,540) | 533,752,000 | 258,558,692 | 90,188,085 | 2,644,641 | 37,055,252 | 124,121,778 | 309,823 | 8,314,062 | 7,184,302 | 5,375,461 |
| Less Present Revenue | 5,694,398 | 498,729,671 | 237,182,459 | 80,889,750 | 2,518,399 | 35,454,697 | 122,685,631 | 262,420 | 8,227,629 | 6,575,359 | 4,933,326 |
| FRP Revenue Change | ***(10,150,937)*** | ***35,022,329*** | ***21,376,232*** | ***9,298,335*** | ***126,242*** | ***1,600,555*** | ***1,436,146*** | ***47,403*** | ***86,433*** | ***608,943*** | ***442,135*** |
| | Percent Total Revenue Increase | 7.02% | 9.01% | 11.50% | 5.01% | 4.51% | 1.17% | 18.06% | 1.05% | 9.26% | 8.96% |

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

| ENO Account(s) | Electric Adjustment DR/(CR) | Gas Adjustment DR/(CR) |
|---|---|---|
| **ADV01 – BRAR Revenues** | | |
| RSRRT: 440-445 SALES-RETAIL REVOTH: Sales Revenue (2) | $ 394,867 | - |
| **ADV02 – OPEB Expense** | | |
| OMAG926: 926 PENSIONS & BENEFITS (LOMTOA) ASC 715 926NS1: ASC 715 NSC - Emp Pens & Ben | $ (1,486,328) | $ (1,012,727) |
| **ADV04 – AMI Meter Reading Expense** | | |
| OMCA902: 902 METER READING EXPENSE (CM-CC-TO) 902000: Meter Reading Expenses | $ (180,757) | $ (875,768) |
| **ADV05 – Test Year Revenues** | | |
| RSRR: 440-445 SALES-RETAIL 440000: Residential Sales | $ 2,614,804 | |
| RSRR: 440-445 SALES-RETAIL 442100: Commercial Sales | $ 1,104,511 | |
| RSRR: 440-445 SALES-RETAIL 442200: Industrial Sales | $ 1,084,096 | |
| RSRR: 440-445 SALES-RETAIL 444000: Public Street & Hwy Lighting | $ 56,344 | |
| RSRR: 440-445 SALES-RETAIL 445000: Other Sales To Pub. Authorit | $ 31,294 | |
| RSRRFRP: 440-445 SALES–RETAIL - FRP REVFRP: FRP Revenue | $ 408,480 | |
| RSRRT: 480 - 481 GAS SALES-RETAIL REVOTH: Sales Revenue | | $ 2,340,836 |
| **ADV06 – FIN48 Interest** | | |
| OCFBL: BANK LOANS - INTEREST EXP (RBTOA) | $ (215,572) | $ (16,822) |
| **ADV07 – GIRP Depreciation** | | |
| 870000: Operation Supervision & Eng | - | $ (863,348) |
| 887000: Maint. Of Mains | | $ (125,031) |
| 926000: Employee Pension & Benefits | | $ (7,387) |
| 926NS1: ASC 715 NSC - Emp Pens & Ben | | $ (2,146) |
| 4030AM: Depreciation Expense | | $ (486,285) |
| 408105: Taxes Other Than Inc-Util Op | | $ (2,087) |
| **ADV08 – NOPS Deferral** | | |
| OMP546: 546 OPERATION SUPVSN & ENGINEERING (PG-DD-TO) 546000: Operation Superv & Engineerin | $ (8,769) | |
| OMP548: 548 PROCESS CONTROL COSTS (PG-DD-TO) 548000: Generation Expenses | $ (9,751) | |
| OMP549: 549 MISC OTH POWER GENERATING EXP (PG-DD-TO) 549000: Misc Oth Pwr Generation Exps | $ (5,139) | |
| OMP551: 551 MAINT SUPVSN & ENGINEERING (PG-DD-TO) 551000: Maint Supv & Engineering | $ (1,816) | |
| OMP552: 552 OTH PWR MAINT-MAINT OF STRUCTURES (PG-DD-TO) 552000: Maintenance Of Structures | $ (4,792) | |
| OMP553: 553 MAINT - GENERATION & ELEC EQUIP (PG-DD-TO) INCLUDES Union LTSA EXP 6948810 553000: Maint-Gener & Elec Equipment | $ (5,207) | |
| OMP554: 554 OTH PWR MAINT- MAINT MISC OTH PWR GEN PLT (PG-DD-TO) 554000: Maint-Misc Other Pwr Gen Plt | $ (2,852) | |
| OMAG926: 926 PENSIONS & BENEFITS (LOMTOA) 926000: Employee Pension & Benefits | $ (5,103) | |
| 926NS1: ASC 715 NSC - Emp Pens & Ben | $ (1,516) | |

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

| ENO Account(s) | Electric Adjustment DR/(CR) | Gas Adjustment DR/(CR) |
|---|---|---|
| TOFE: 408.110 EMPLOYMENT TAXES (LOMTOA) 408110: Employment Taxes | $ (1,315) | |
| **ADV09 – Storm Proforma Costs** | | |
| PLD361: 361 STRUCTURES & IMPROVEMENTS (DS-DD-TO) 1010AM: Electric Plant In Service | $ (22,722) | |
| PLD362: 362 STATION EQUIPMENT (DS-DD-TO) 1010AM: Electric Plant In Service | $ (444,038) | |
| PLD364: 364 POLES, TOWERS, & FIXTURES (D2-DD-TO) 1010AM: Electric Plant In Service | $ (370,666) | |
| PLD365: 365 OVERHEAD CONDUCTORS & DEVICES (D2-DD-TO) 1010AM: Electric Plant In Service | $ (476,416) | |
| PLD368: 368 LINE TRANSFORMERS (DX-DD-TO) 1010AM: Electric Plant In Service | $ (571,950) | |
| PLD3691: 369.1 OVERHEAD SERVICES (DV-CC-TO) 1010AM: Electric Plant In Service | $ (260,165) | |
| DXD361: 361 STRUCTURES & IMPROVEMENTS (DS-DD-TO) 4030AM: Depreciation Expense | $ (192) | |
| DXD362: 362 STATION EQUIPMENT (DS-DD-TO) 4030AM: Depreciation Expense | $ (113,371) | |
| DXD364: 364 POLES, TOWERS, & FIXTURES (D2-DD-TO) 4030AM: Depreciation Expense | $ (71,262) | |
| DXD365: 365 OVERHEAD CONDUCTORS & DEVICES (D2-DD-TO) 4030AM: Depreciation Expense | $ (137,540) | |
| DXD368: 368 LINE TRANSFORMERS (DX-DD-TO) 4030AM: Depreciation Expense | $ (241,362) | |
| DXD3691: 369.1 OVERHEAD SERVICES (DV-CC-TO) 4030AM: Depreciation Expense | $ (30,916) | |
| **ADV10 – Union PB1 Outage** | | |
| 283345: Misc Cap Costs-Fed | 512,415 | |
| 283346: Misc Cap Costs-State | 167,676 | |
| 1823AC: 182 REGULATORY ASSET- OTHER 182000: Other Regulatory Assets | (2,607,711) | |
| OMP553: 553 MAINT - GENERATION & ELEC EQUIP (PG-DD-TO) INCLUDES Union LTSA EXP 6948810 553000: Maint-Gener & Elec Equipment | (1,303,855) | |
| **Adv11 – Utility Conflict Survey** | | |
| 1823GBD: 182 REGULATORY ASSET - GAS BORING DEFERRAL 1823GB: ENOL Gas Boring Deferral | - | $ (1,754,817) |
| **ADV12 – Proform Regulatory Assets** | | |
| 283307: ADIT Other - Reg Assets - Fed | 852,289 | $ 133,914 |
| 1823CM: 182 REGULATORY ASSET - ALGIERS CUST MIGRATION 1823CM: Reg Asset - Algiers Cust Migra | (1,078,956) | |
| 1823ERC: 182 REGULATORY ASSET - ENOL RATE CASE 2018 1823N8: Reg Asset ENOL Rate Case 2018 | (2,189,022_ | $ (513,474) |
| **ADV13 – UPITA** | | |
| 254SCT: 254 REGULATORY LIABILITY – TCJA -SMART CITY 254SCT: ENO Tax Liability - Smart City | (853,889) | |